Decision No. C21-0385

**BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF COLORADO**

PROCEEDING NO. 21R-0314G

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IN THE MATTER OF THE PROPOSED RULES ADDRESSING GAS COST ADJUSTMENT APPLICATIONS FILED PURSUANT TO THE RULES REGULATING GAS UTILITIES, 4 CODE OF COLORADO REGULATIONS (CCR) 723-4.

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# NOTICE OF PROPOSED RULEMAKING

Mailed Date: June 30, 2021
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# I. BY THE COMMISSION

## A. Statement

1. The Colorado Public Utilities Commission issues this Notice of Proposed Rulemaking (NOPR) to amend the Commission's Rules Regulating Gas Utilities, 4 *Code of Colorado Regulations* (CCR) 723-4 (Gas Rules). The proposed amendments revise provisions in the rules governing the filing of gas cost adjustment applications at 4 CCR 723-4-4600, *et seq*.

2. The purpose of this NOPR is to address, on a prospective basis, the recovery of gas costs incurred by Colorado natural gas utilities to address the potential for increased volatility in gas costs, especially in the wake of the extreme weather event that occurred in February 2021.

3. As explained below, we seek to ensure that the incurrence and recovery of natural gas costs are accomplished in a way that is equitable to both the utilities and their customers. We aim to reexamine the policies around how utilities buy natural gas, manage their supply operations, and experience the associated cost impacts along with their customers. We will engage with the gas utilities and other interested stakeholders in realigning the financial incentives faced by the Colorado gas utilities. We specifically examine potential modifications to the Gas Cost Adjustment (GCA) rate mechanism framework with the goals of opening up opportunities for the utilities to secure profits when achieving savings in gas costs and of

preventing utilities and their natural gas commodity suppliers from taking for granted dollar-for-dollar recovery of all incurred costs.

## B. Background

### 1. 21I-0076EG: Investigation into February 2021 Weather Event

The State of Colorado, as well as much of the central United States, experienced extremely cold weather beginning February 13, 2021. The natural gas commodity market reacted to the event by raising clearing prices to unprecedented levels on the order of $190 per MMBtu at the Rocky Mountain - Cheyenne Hub and $150 per MMBtu at the West Texas Permian Basin – Waha Hub.

4. On February 17, 202, in immediate response to the weather event and the ensuing high market prices, the Commission issued Decision No. |C21-0087 opening Proceeding No. 21I-0076EG and directing the state's investor-owned gas and electric utilities to file "Situation Reports."

5. By Decision No. C21-0101, issued on February 24, 2021, the Commission directed the utilities to file additional information in their Situation Reports as the magnitude of incurred natural gas costs came to light. For instance, the Commission noted that both Atmos Energy Corporation (Atmos) and Public Service Company of Colorado (Public Service) each made filings with the United States Securities and Exchange Commission (SEC) that addressed, in part, the extreme weather event of February 13-16, 2021. Atmos, in its SEC 8K filing, indicated that it had expended between $2.5 billion and $3.5 billion for the purchase of natural gas to serve its gas customers in Colorado, Texas, and Kansas during the extreme weather event. Public Service, in its SEC 10K filing, indicated that it had expended roughly $650 million for the purchase of natural gas to serve its electric and gas customers in Colorado.

6. The Commission again sought additional information for its investigation into the February 2021 weather event by Decision No. C21-0149, issued March 12, 2021. The Commission specifically requested updated financial figures to include the period from February 17-19, 2021 and sought the costs estimated to be attributable to the residential and commercial customers.

7. Below is a brief summary of each utility's situation report explaining the February 2021 event.

**a. Public Service Company of Colorado**

8. Public Service filed its Situation Report on March 5, 2021. Public Service explained that it serves actual customer demand on any given day using a mix of long-term (baseload) purchases, daily (spot) purchases, and gas held in underground storage. Baseload purchases are fixed volumes that flow every day for a term of one month or longer and settle at prices established on the first of every month. Spot market purchases vary by day based on forecast customer demand and settle at daily spot market prices on a day-ahead basis. Storage gas withdrawals also vary by day based on actual system requirements. Public Service stated that it plans to use a portion of the daily storage withdrawal capability each day to meet forecast customer demand, while reserving a portion of the withdrawal capability to manage forecast uncertainty, unforeseen supply curtailments, or other system contingencies.[1]

9. Public Service stated that it trades in natural gas primarily on the InterContinental Exchange (ICE) electronic trading platform where Gas Supply places bids to buy and lifts offers to sell based on trading volume and velocity of trades that are happening in real-time in the

[1] Public Service Situation Report, p. 20.

Rockies region and the Mid-Continent region.[2] Public Service stated that significant gas can leave the Colorado area for transportation to Minneapolis and Chicago, and that Colorado must frequently "out-bid" Mid-Continent prices to keep gas from leaving Colorado, as occurred during the price run-up the few days preceding the ICE designated trade day (February 12, 2021) for February 13-16, 2021. Public Service stated that, as is common industry practice, it traded on "Index + Premium" prices in the early morning on February 12, 2021, before fixed price bids were available. Public Service stated that the Cheyenne Hub index settled at $187.69 per Dth, with the maximum price offered $350 per Dth. Public Service stated that the average fixed-price that Public Service paid for natural gas was $157.16 per Dth, below the index settlement price and well below the high market bid.[3]

Public Service stated that, with respect to storage, its policy is to hold a minimum of 250,000 Dth of storage gas in reserve daily from November to March each year to cover forecast errors and other operational issues such as well freeze offs or pipeline mechanical failures. Public Service explained that, as the utility's load forecast approaches the design day temperature (an average of -10 degrees through the day), it anticipates that its reserve margins would be fully utilized and approach zero as the maximum upstream pipeline services contracts, both transportation and storage, are used. Public Service stated that it has not experienced the Design Day Peak

[2] Public Service purchases gas for delivery at the Colorado Interstate Gas (CIG) and Cheyenne market hubs.

[3] Public Service Situation Report, p. 31.

temperature mean of minus 10 degrees, nor has it experienced the Design Day Peak loads, since 2006. As such, the Company has not fully exhausted its reserve margins since 2006. Public Service further noted that reserves are not only exhausted on Design Day Peak days and that there have been many days when a portion or nearly all of the gas in reserve was needed to cover higher than anticipated load or supply disruptions.[4]

10. Public Service stated that it purchased enough natural gas to ensure sufficient reserves while forecasted and actual customer demand climbed higher throughout the bitterly cold February 2021 weekend.[5]

11. Public Service stated that unprecedented decreases of 25 to 33 percent in the nation’s natural gas supply availability, in combination with the substantial increase in demand for natural gas and electricity, caused a dramatic short-term increase in natural gas prices. For example, natural gas prices prior to the cold weather were running in the range of $2 to $3 per Dth, but, by Friday, February 12, 2021, Public Service experienced prices 100 times that price, with some running as high as $900 per Dth in Oklahoma.[6]

12. Public Service provided historic daily mid-point prices for natural gas in its situation report for the days coinciding with the February 2021 event.[7]

| | CIG Daily Mid-Point (Max) | | Cheyenne Daily Mid-Point (Max) | |
|---|---|---|---|---|
| | 2011-2020 | 2021 | 2011-2020 | 2021 |
| 9-Feb | $6.96 | $3.40 | $7.02 | $3.42 |
| 10-Feb | $6.96 | $3.46 | $7.02 | $3.48 |
| 11-Feb | $8.25 | $4.83 | $9.93 | $5.64 |
| 12-Feb | $6.07 | $13.29 | $6.67 | $14.84 |

[4] Public Service Situation Report, p. 28-29.

[5] Public Service Situation Report, p. 3.

[6] Public Service Situation Report, p. 4.

[7] Public Service Situation Report, p. 20.

| | | | | |
|---|---|---|---|---|
| 13-Feb | $5.27 | $172.95 | $5.50 | $187.69 |
| 14-Feb | $5.14 | $172.95 | $5.24 | $187.69 |
| 15-Feb | $5.27 | $172.95 | $5.35 | $187.69 |
| 16-Feb | $5.27 | $172.95 | $5.35 | $187.69 |

13. Public Service stated that, consistent with market practices, it secured the estimated remaining natural gas needs, beyond base amounts and storage withdrawals, for its gas and system on Friday, February 12, 2021, to account for demand over the four-day holiday weekend and that, consistent with its pre-approved GPP, the price for the unhedged portion of the gas purchases was the market settled index prices at various local delivery points on its system. However, because of the unprecedented supply-demand imbalance in the natural gas markets, those index prices were around 100 times greater than the day prior. Public Service stated that purchasing the four-day block of gas nevertheless was critical to ensuring adequate gas supply over the holiday weekend and to maintaining reliable service; yet having to buy in a four-day block limited its ability to mitigate increases in fuel costs and impacts on its customers.[8]

14. Public Service stated that had the Company not made this four-day block purchase, it would have faced a substantial risk of having inadequate gas supply over the weekend and very likely could have compromised the ability to maintain gas service for its customers.[9]

15. Public Service stated that, with respect to the February extreme weather event, it purchased gas supply for its customers through a variety of sources including storage gas, monthly purchases, and in the day-ahead market. In determining the amount of gas necessary to acquire via daily purchases on Friday, February 12, 2021 for the holiday weekend, Public

[8] Public Service Situation Report, p. 4.
[9] Public Service Situation Report, p. 21.

Service considered the peak load needs plus reserves, less gas available from storage, less gas available from the monthly purchased baseload supplies. Public Service stated that, due to its Commission-approved Gas Purchase Plan,[10] it was able to source over 67 percent of its gas supply from baseload purchases and storage gas over the event, which limited the amount of day-ahead spot market purchases, significantly lowering exposure to extremely high gas prices. Based on preliminary estimates, the implementation of its GPP resulted in avoided costs of approximately $672 million dollars.[11]

16. Public Service explained that it did not implement reliability-based conservation appeals or public appeals in response to the February weather event, stating that such drastic steps are only for the purpose of maintaining system reliability when there is a significant risk of forced outages due to dire system emergencies, where system integrity is at risk. Public Service stated that it could not reasonably and responsibly have purchased materially lower amounts of natural gas going into Presidents' Day Weekend on the hope that its customers would respond to such appeals—particularly given the historically cold temperatures. Public Service argued that such appeals would not have given customers the optionality to avoid the high market prices, that conservation measures taken by customers would not have materially lowered their bills.[12]

17. As preliminary estimates, Public Service stated that for its GCA, the average cost of gas for the first quarter of 2021 was $2.47 per Dth. In contrast, the February event produced

[10] See Rules 4605 (Gas Purchase Plans) and 4606 (Contents of the GPP). GPPs for 2020-2021 heating season were filed by the utilities on May 29, 2020 through June 2, 2020 as follows: Atmos: Proceeding No. 20P-0241G; CNG: 20P-0293; Black Hills: Proceeding No. 20P-0232G; and Public Service: 20P-0240G.

[11] Public Service Situation Report, pp. 12-13.

[12] Public Service Situation Report, p. 36-37.

an average cost of gas of $58.20 per Dth and an estimated under-recovered balance of $327 million for the four-day event.[13]

18. Public Service stated that it settled a $750 million first-mortgage bond on March 1, 2021, a transaction already planned, but upsized by $350 million. In addition, Xcel Energy subsequently infused $250 million of equity to preserve the credit worthiness and capital structure of Public Service and to provide necessary liquidity to pay for the substantial costs incurred during the event.[14]

19. In its supplemental report filed on March 19, 2021, Public Service estimates that the total incremental costs of the February 2021 weather event was $338.5 million.[15]

**b. Atmos Energy Corporation**

20. Atmos also filed its Situation Report on March 5, 2021.

21. As a general matter, Atmos explained that it purchases both its first of the month and daily natural gas requirements based on multiple pipeline indices.[16] Atmos stated that gas over weekends and holidays is purchased the morning of the business day immediately prior.[17]

22. Atmos stated that it had contracted to provide 100 percent of its requirements for the February 13-16, 2021 time period prior to February 8, 2021. The contracts used a combination of baseload and day-ahead purchases to provide all gas required. Baseload amounts are priced at a first-of-the-month (FOM) index reference price. Day-ahead purchases are priced

[13] Public Service Situation Report, p. 33.
[14] Public Service Situation Report, pp. 38-39.
[15] Public Service Supplemental Report, p. 8.
[16] Atmos Situation Report, p. 2.
[17] Atmos Situation Report, p. 3.

at the Gas Daily index reference price. Atmos states that while the contracts were final, volumetric elections under those contracts still had to be made leading up to the event.[18]

23. Atmos stated the total estimated cost of the Company's purchases throughout the weather event was approximately $26 million, because of the unusually high market prices during this time. The preliminary estimates by GCA rate area were:[19]

| | North | Southeast | Southwest |
|---|---|---|---|
| Per Residential Customer | $180 | $104 | $28 |
| Per Commercial Customer | $1,120 | $410 | $149 |

24. Atmos stated that it had sufficient capacity to serve all customers during the period. Because curtailment under its tariffs refer to the inability of a customer to receive gas due to a shortage of gas, supply, Atmos' interruptible and curtailable customers were not directed to interrupt or curtail load in order to reduce consumption over the weekend of February 13-16, 2021.[20]

25. Atmos stated that it did not have excess or unconsumed gas from its purchases to serve load over the period February 13 to 16 that could be sold to other utilities.[21]

**c. Black Hills Colorado Gas**

26. Black Hills filed its Situation Report on March 8, 2021.

27. Black Hills explained that gas purchases in the daily market are generally for gas to flow the next business day, but that gas purchases made on Fridays are typically for delivery

[18] Atmos Situation Report, p. 2.
[19] Atmos Situation Report, p. 4.
[20] Atmos Situation Report, p. 4.
[21] Atmos Situation Report, p. 4.

on Saturdays, Sundays, and Mondays, and that in the case of three-day holiday weekends, gas trading on Friday will also cover Tuesday the following week.[22]

28. Black Hills explained that its daily gas purchases are made in two ways: firm peaking and daily index purchases. Firm peaking contracts are contracts in place with upstream suppliers in which the utility reserves a volume of gas that may be called upon if needed. Thus, in the event gas usage exceeds baseload volumes, Black Hills will call upon the firm peaking volumes. Black Hills stated that it entered into firm peaking contracts with upstream suppliers in August 2020 for the contract month February 2021 for volumes priced at daily index prices, if and when the firm peak volumes are called upon. Daily index purchases are gas purchases contracted the day before, or day of, gas delivery, priced at the daily index prices and are made after baseload and firm peaking volumes are exhausted. When consumption exceeds its baseload contract volumes, Black Hills uses its firm peaking contracts, followed by the procurement of gas through daily index purchases.[23]

29. With respect to storage, Black Hills contracts services with upstream pipelines. Generally speaking, Black Hills injects gas into the upstream supplier's storage field during warmer months (May – October) when natural gas prices are typically lower and it withdraws gas from the upstream supplier's storage fields during the cooler months (November – April) when spot prices are generally higher. Instead of customers paying the high spot prices during the cooler months.[24]

[22] Black Hills Situation Report, p. 8.
[23] Black Hills Situation Report, p. 14.
[24] Black Hills Situation Report, pp. 16-17.

30. Black Hills explained that, in general, it recovers its gas supply costs through the GCA as "a pass-through cost" with no utility mark-up. Black Hills revises its GCA annually through an application filed with the Commission with an effective date of November 1. Without citing a Commission rule, Commission order, or tariff requirement, Black Hills stated that it may make an interim GCA filing if the resulting change to the GCA equates to at least one cent ($0.01) per Dth.[25]

31. Black Hills explained that per Rule 4607(c), for purposes of GCA recovery, the standard of review to be used in assessing the utility's action (or lack of action) in a specific gas purchase year is: whether the action (or lack of action) of a utility was reasonable in light of the information known, or which should have been known, at the time of the action (or lack of action).[26]

32. Black Hills further explained that under Rule 4609(b), a utility shall monitor the net under- or over-recovery balance in Account No. 191 on a monthly basis. On a quarterly basis, or as otherwise established individually for a utility, a utility shall file, within 30 days of the end of the quarter, a report to the Commission stating the Account No. 191 balance calculation for each rate area. If the utility identifies a significant net under- or over-recovery balance during the gas purchase year, the utility shall initiate appropriate action to mitigate the significant under- or over- recovery balance.

33. Black Hills stated for the February 2021 event, it created a separate subaccount in Account No. 191.[27] Black Hills stated that it experienced a new system peak demand day on

[25] Black Hills Situation Report, pp. 32-33.
[26] Black Hills Situation Report, p. 33.
[27] Black Hills Situation Report, pp. 33-34.

February 14 of 210,911 Dth, as compared to the previous peak of 202,009 Dth.[28] Black Hills stated that not a single customer lost gas service because of the event.[29] Black Hills further reported that it experienced no material reductions in gas supply from February 13 through 16.[30]

34. Black Hills described the market conditions during the February 2021 weather event as "chaotic." Black Hills stated that the upstream pipeline operators started issuing cold weather alerts on February 9 issued critical notices with operational flow orders (OFOs) and assessments of potential penalties. Black Hills stated that it held storage withdrawals in reserve to help mitigate potential overrun penalties and to have an emergency source of supply on an intraday basis due to freeze offs or colder than forecasted weather.[31] For example, Black Hills stated that over the February 13-16 period, many upstream pipelines issued Under Delivery OFOs that mandated financial penalties against Black Hills in the event it took more gas off the system than contracted. As a result, Black Hills bought sufficient gas based on forecasted gas loads, taking into account storage withdrawals during the event to avoid OFO penalties, which were up to $25 per Dth of under-delivery for some GCA areas in addition to the index price of gas.[32]

35. Black Hills further described the event as "market based" because no one predicted the dramatic price spike that occurred when compared to previous cold weather events.[33]

[28] Black Hills Situation Report, p. 3.
[29] Black Hills Situation Report, p. 4.
[30] Black Hills Situation Report, p. 5.
[31] Black Hills Situation Report, p. 8.
[32] Black Hills Situation Report, p. 30.
[33] Black Hills Situation Report, p. 8.

36. Black Hills stated that the supply of natural gas for February 13-16, 2021 was served by a combination of baseload purchases, storage withdrawals, and daily gas purchases. The baseload supply contracts are priced at Inside FERC First of Month Index prices and do not fluctuate through the month, and thus, the mid-month price spike that occurred in February did not affect the cost of baseload purchases. Black Hills estimated the baseload supply purchases saved its customers $44.2 million of the $48.7 million in the total savings of gas purchased during the event.[34]

37. Black Hills stated that it subscribes to the Web ICE trading platform, which provides access to real-time trading activity and pricing and supports purchasing at market-based prices. With respect to the event, Black Hills stated that the anticipated demand for Rockies gas necessitated transacting Gas Daily index related supply packages as early in the morning of February 12 as possible. Black Hills stated that it agreed to the market-based premiums and completed its transactions for supply.[35]

38. Black Hills stated that based on discussions among its gas supply managers and suppliers of natural gas, it was confident that its system could perform safely and reliably in the face of the event and no mandatory customer curtailment action was necessary for supply availability and reliability.[36]

39. Black Hills stated that it offers interruptible service to a very limited number of commercial customers, but did not direct interruptible customers to curtail in order to reduce consumption over the February 13-16, 2001 timeframe, because interruption is defined as the

[34] Black Hills Situation Report, pp. 13-14.
[35] Black Hills Situation Report, p. 22.
[36] Black Hills Situation Report, p. 24.

inability of the Company to deliver gas supplies to a customer due to constraints on the system and curtailment, yet the utility had adequate gas supply using baseload purchases, daily gas purchases and storage services such that there were no supply constraints.[37]

40. Black Hills estimated that the incremental gas commodity costs to serve customers due to the event was approximately $75 million. Depending on the GCA rate area, and using a 24-month amortization period, the preliminary residential customer bill impact ranges from approximately $6.40 to $18.50.[38]

41. Black Hills stated that its parent company, Black Hills Corporation closed on an $800 million unsecured term loan maturing in nine-months on November 24, 2021 with an interest rate of LIBOR plus 75 basis points for proceeds to fund the natural gas purchases made in February 2021 (by its subsidiaries) and provide additional liquidity. Black Hills expects to repay a portion of this loan prior to maturity and refinance a portion with long-term debt or other options. Black Hills states that the term loan allows Black Hills Corporation to pay down a portion or all of the loan with no prepayment penalty prior to maturity.[39]

#### d. Colorado Natural Gas

42. CNG also filed its Situation Report on March 8, 2021. CNG stated that it has an obligation to ensure reliability of service and explains that its gas procurement activities are designed to ensure gas service to customers at periods of peak demand. CNG stated that, particularly during an extreme weather, its customers rely upon continuous natural gas service to ensure their health and welfare. CNG stated that it necessarily has to procure sufficient supplies

[37] Black Hills Situation Report, p. 26.
[38] Black Hills Situation Report, p. 25.
[39] Black Hills Situation Report, p. 32.

of natural gas to meet projected peak demand regardless of customer response to calls for conservation.[40]

43. CNG explained that it manages its natural gas supply through a combination of hedges, fixed price contracts, and gas purchased at index pricing. CNG stated that, in a wide range of weather and market conditions, CNG's procurement practices help it keep the cost of gas low. However, according to CNG, the historic spike in natural gas prices during the period of February 13-16, 2021 fell outside the typical range of forecastable market conditions with market prices in a period of less than 48 hours. CNG explained that it nonetheless followed its usual procurement practices in preparing for this winter event but also implemented additional measures, including reaching out through multiple channels to encourage customers to conserve energy and making daily nomination adjustments throughout the long weekend.[41]

44. CNG stated that in light of the weather advisories, pipeline notices, and increasing demand for regional gas supply, it purchased its weekend supply for the February 13-16, 2021 period on Thursday evening, February 11, 2021, to ensure sufficient natural gas for the upcoming 4-day weekend.[42] CNG claimed that it had severely limited options to acquire natural gas supplies necessary to meet customer demand during this weather event, and was forced to accept transactions at historically high prices in order to fulfill its obligation to ensure service reliability.[43]

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[40] CNG Situation Report, p. 6.

[41] CNG Situation Report, p. 2.

[42] CNG Situation Report, p. 8.

[43] CNG Situation Report, pp. 8-9.

45. CNG stated that the most dramatic price spikes began on Saturday, when the gas for the long weekend had necessarily already been procured.[44]

46. CNG stated that it had no gas in storage prior to February 8, 2021 to serve load over the period of the weather event.[45]

47. CNG explained that, pursuant to its General Rules and Regulations for Natural Gas Service, the utility may only curtail service to customers in cases of supply shortages. CNG curtailed one customers in Pueblo, Colorado beginning February 13, 2021 and ending on February 15, 2021 due to a curtailment of supply. CNG stated that no other orders of curtailment were issued because supply remained available on transmission lines feeding its associated distribution systems.[46]

48. In a supplemental report filing dated March 19, 2021, CNG stated that the estimated total cost of incremental gas purchases for February 2021 is approximately $7.0 million and that there were $1.9 million of potential penalties from Public Service for transportation service but had not received a bill yet for those amounts.[47]

### 2. 21M-0130EG: Initial Actions on Cost Recovery

49. On March 23, 2021, by Decision No. C21-0179, the Commission opened Proceeding No. 21M-0130EG to commence its consideration of the impacts of the February 2021 weather event on the revenue requirements and rates of Colorado's investor-owned electric and natural gas utilities.

[44] CNG Situation Report, p. 3.
[45] CNG Situation Report, p. 4.
[46] CNG Situation Report, p. 5.
[47] CNG Supplemental Report, pp. 2-3.

50. The Commission prohibited the natural gas utilities from addressing the recovery of the extraordinary costs of the February extreme weather event through the normal course of the implementation of the GCA rate mechanisms and instead directed them to isolate the extraordinary costs associated with the February extreme weather for the purpose of proposing discrete methods for cost recovery in separate, utility-specific proceedings.

51. The Commission also sought to establish certain guidelines and timelines for the Colorado gas utilities to make their individual filings addressing the recovery of the extraordinary costs associated with the February extreme weather event to ensure efficient and timely consideration of their specific requests. In establishing such guidelines and timelines, the Commission took administrative notice of the information filed by the utilities in their Situation Reports described above.

52. By Decision No. C21-0261, issued on April 30, 2021, the Commission permitted the gas utilities to file applications to address the recovery of the costs incurred as a result of the February 2021 weather event from their customers through rates. The Commission directed those application filings to contain certain information, including:

- A detailed timeline of events and when information was available to the utility, covering weather forecasts, load forecasts, gas hub pricing, actual gas purchases, gas supply offers received, actual gas usage, storage withdrawals, customer communication, curtailments, contract price settlement, etc.
- A detailed accounting of timing, volumes, and pricing of all gas supplies used to serve customer load over the period including long and short-term purchases, storage withdrawals, and pipeline balancing volumes and charges by rate area.
- A detailed accounting of gas storage including volumes in storage prior to the event, withdrawal limits, volumes used over the course of the event, etc., by rate area.
- A detailed accounting of actual gas demand by rate area and customer class.
- All customer communications with details on the timing and distribution of the communications and estimated impact on customer behavior.

- Information regarding baseline February gas forecasts for the implementation of the utility's GCA including: expected gas demand, volume, and pricing of purchases, storage volume and pricing, and any other costs included in the GCA.
- A detailed description of the management review process for the gas supply and demand decisions over the event period, including details regarding when and how decisions were made as to gas supplies (both purchased and in storage), what and when to communicate with customers, what other actions were discussed or taken to address the extraordinary event, etc.

53. The Commission's actions in Proceeding No. 21M-0130EG supported the ability of the Colorado utilities to assure their customers that bills in the near-term would not include any of the unusually high gas prices from the February event. They likewise supported the utilities in their efforts to secure any additional financing required to cover the extraordinary gas costs at a reasonable cost.

54. The Commission actions further enabled the utilities to report solid financial results for the three months January through March 2021.

55. Atmos' financial presentations in May 2021, for example, make little mention of the February event; instead, Atmos presents strong financial results with an emphasis on ongoing capital expenditures supported with favorable cost recovery mechanisms such as its System Safety and Integrity Rider (SSIR).[48]

56. In contrast to Atmos' presentations, the presentations made by Black Hills Corporation, the parent of Black Hills, highlighted the significant regulatory asset (approximately $559 million) associated with what was unofficially dubbed "Winter Storm Uri." Black Hills Corporation also noted that the cost recovery filings planned for the second quarter

[48] Atmos Energy Corporation Analyst Update May 2021:
ttps://www.atmosenergy.com/company/financial-news

of 2021 and an assumption of favorable regulatory outcomes supported its earnings estimates for 2022.[49]

57. Xcel Energy, the parent of Public Service, also identified impacts from the February weather event in its recent financial presentations, citing both the need for Xcel Energy to secure incremental debt for the assumed lag in gas cost recovery from ratepayers and calculating $308 million of costs for its Colorado gas operations.[50] Nevertheless, Xcel Energy also announced an increase in first quarter earnings-per-share results for Public Service to $0.31 in 2021 as compared to $0.24 in 2020.[51]

58. Each of the Colorado gas utilities have subsequently filed applications for approval of cost recovery mechanisms to address the costs they incurred during the February 2021 event in response to Decision No. C21-0261:

- Public Service filed an application covering both its electric and gas utility operations in Proceeding No. 21A-0192EG. For its gas utility, Public Service proposes to recover $287 million from ratepayers over two years with no carrying charge. Alternatively, Public Service proposes a 5-year recovery period with carrying charges calculated at its long-term cost of debt of 3.93 percent.
- Atmos filed an application in Proceeding No. 21A-0186G. Atmos seeks to recover approximately $23.55 million, proportioned across its GCA areas as follows: North—$19,347,269, recovered over 36 months with a carrying cost of Atmos' weighted average cost of capital (WACC); Southeast—$3,120,070, recovered over 36 months with a carrying cost of Atmos' WACC; and Southwest—$1,082,270 recovered over 12 months through the GCA "consistent with normal GCA rules." Atmos further proposes that, should the Commission decline to authorize a carrying cost for the North and Southeast recovery, those amounts could be recovered over 12 months through the GCA.

[49] Black Hills Corporation Investor Presentation May 2021. https://s21.q4cdn.com/494657442/files/doc_events/2021/BKH-May-Investor-Presentation.pdf

[50] Xcel Energy "Future In Sight: AGA Financial Forum, May 19-20, 201." https://s25.q4cdn.com/680186029/files/doc_presentations/2021/05/AGA-Conference-05-19-21.pdf

[51] Xcel Energy First Quarter 2021 Earning Report Presentation, April 29, 2021. https://s25.q4cdn.com/680186029/files/doc_presentations/2021/Xcel-Energy-Earnings-Presentation-2021-Q1-Final.pdf

- Black Hills filed an application in Proceeding No. 21A-0196G. For its gas utility operations, Black Hills proposes to recover $72.7 million, proportioned across its GCA regions as follows: Central and North/Southwest—three years at short and at BHC's long-term cost of debt of 3.91 percent; Western Slope—short term cost of debt for 8 months (covering a term loan from February to November 2021, set at LIBOR plus 75 basis points), and then on additional year at no carrying charge. Black Hills proposes a separate rider that mirrors the GCA, the "Extraordinary Cost Recovery Rider."
- CNG filed an application in Proceeding No. 21A-0188G. CNG proposes to recover $7.1 million over 5 years with a carrying charge equal to its WACC.

### C. Discussion

59. Several states in addition to Colorado are continuing their investigations into the impacts of the February 2021 event. However, much of their focus appears to be on the reliability and resilience of electric utility operations and the organized electric markets in Texas and elsewhere in the Eastern Interconnection. Some attention is also being paid to the interdependence on the electricity supplies and natural gas supply operations within certain regions of the central United States.

60. However, potential shortcomings of the natural gas market may be an area overlooked in the ongoing investigations into the February weather event. For instance, the analysis of "Natural Gas Market Performance During the February 2021 Cold Weather Event" by the American Gas Association, the national trade group representing more than 200 local utilities, only confirms that: (1) the severe cold wave drove U.S. natural gas consumption to a two-day record from February 14 and 15 for primarily heating needs; (2) natural gas storage played a critical role in meeting natural gas demand during the cold wave; (3) conditions led to a significant increase in the spot price of natural gas in many areas; (4) natural gas utilities provided safe and reliable natural gas service to customers during this event with few interruptions; (5) natural gas utilities do not set the market pricing for natural gas; and (6) these

market pricing in the aftermath of severe weather events can be very high and "Utilities may work with their state regulators to mitigate rate shocks to customers resulting from these events through special regulatory treatments, including regulatory assets, deferred purchase gas costs, or securitization.[52]

61. Likewise, in its recently released report titled *The February Artic Event—February 14-18, 2021: Event Details, Lessons Learned and Implications for MISO's Reliability Imperative,* MISO simply resigns itself to the conclusion that: "Since natural gas markets do not operate on weekends or holidays, there was added complication because forward commitments were being made earlier for less certain forecasts farther in the future. Resources were lining up natural gas fuel based on Thursday forecasts of anticipated needs for Tuesday."[53]

62. The Energy Information Association reported in March that while natural gas spot prices at several trading hubs approached record highs during the week of February 14, 2021 due to cold weather and demand imbalances, the elevated spot prices were short lived. EIA stated: "As temperatures rose, alleviating supply constraints and tempering demand, natural gas spot prices at the Henry Hub quickly began to decline to pre-cold snap levels, reaching $2.84/MMBtu on February 22."[54]

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[52] American Gas Association, Energy Analysis EA 2021-01, "Natural Gas Market Performance During the February 2021 Cold Weather Event," April 5, 2021. https://www.aga.org/globalassets/research--insights/reports/energy-analysis-2021-01-natural-gas-market-performance-during-the-february-2021-cold-weather-event.pdf.

[53] MISO. The February Artic Event—February 14-18, 2021: Event Details, Lessons Learned and Implications for MISO's Reliability Imperative. https://cdn.misoenergy.org/2021%20Arctic%20Event%20Report554429.pdf

[54] U.S. Energy Information Administration. Cold Weather Brings Near Record-High Natural Gas Spot Prices. *Today in Energy*, March 5, 2021. https://www.eia.gov/todayinenergy/detail.php?id=47016#:~:text=Natural%20gas%20spot%20prices%20at,of%20the%20Lower%2048%20states.

63. Notwithstanding the “short-lived” nature of the record high market prices, the magnitude of the costs incurred by the Colorado gas utilities were substantial, and, as noted above, their customers will not likely experience them as a weeklong phenomenon. The February event has revealed how retail gas utility customers have no control over the pricing of the gas they receive as the utilities make all of the purchasing decisions. In most cases, ratepayers are not even given a warning of the high costs the natural gas market will impose upon them. We thus find it necessary to assess the proposition that the price of natural gas is out of the control of utilities due to of the magnitude of the cost impacts on Colorado gas utility customers. We are further interested in examining: (1) whether those entities who the utilities claim to have substantial control over the price of natural gas offer the necessary products and services to help them (the utilities) manage gas costs and mitigate price risk and, relatedly, (2) whether the expectation of the full recovery of actual, prudently incurred expenditures from the utility’s customers through the GCA mechanism has resulted in the potential for recurring windfalls to the utilities’ gas suppliers because the utilities have insufficient motivation to prevent them. While we do not dispute that Colorado gas utility customers have benefitted from declining cost of natural gas being passed through quickly through the GCA in recent years, those benefits do not appear to justify periodic yet opportune inflexibility in the natural gas market that serves the interests of certain savvy market participants at the expense of the GCA ratepayers.

64. Furthermore, in a letter to the Commissioners, AGA joined the Edison Electric Institute, the parallel electric utility trade organization, in a response to Colorado Governor Jared Polis[55] by pointing out that, like many other states across the nation, Colorado regulation allows

[55] Governor Polis Letter, February 23, 2021, filed in Proceeding No. 21I-0076EG.

natural gas utilities to recover in rates the price of natural gas costs set by the market and passed through directly to customers. AGA and EEI note, as the Colorado utilities stated in their filings in both Proceeding Nos. 21I-0076EG and 21M-0130EG, that regulated utility companies do not profit if natural gas costs increase. AGA and EEI further point out that in recent years, natural gas prices have been historically low, but that during February's extreme weather event, market prices for natural gas "skyrocketed." They suggest that (1) existing cost-recovery policies should not be changed retroactively[56] and (2) the Commission should work with the Colorado utilities to determine how best to recover natural gas costs in ways that are fair to customers and companies.

65. We agree with AGA and EEI regarding the need to examine the recovery of natural gas costs in a way that is fair to both the utilities and their customers. As suggested in their letter, the Commission will re-examine policies around how utilities buy natural gas and how they then recoup the associated costs. While we concur with AGA and EEI that hedging can help utilities secure a certain portion of their natural gas supply in a manner that limits ratepayers' overall exposure to unforeseen and extraordinary market prices, we are not prepared to conclude that more long-term contracts and other forms of hedging prescribed by Commission rules and orders are themselves sufficient to protect customers during events such as the one experienced in February 2021.

66. Public Service states it did not like the market prices that resulted from the event and their subsequent impacts on its customers. It acknowledges that the unexpected and record-breaking market prices experienced on Friday, February 12 and applicable to the natural gas secured for the four-day holiday weekend, were exceptionally high and resulted in significant

[56] As explained above, the Commission is examining the recovery of costs as a result of the February 2021 weather event in separate application proceedings.

increases in natural gas costs.[57] Public Service further states that it has been the practice and procedure of the Colorado Commission, as well as the vast majority of the regulatory bodies across the country, to allow for the recovery of actual, prudently incurred expenditures for gas at cost from the utility's customers. Public Service states that the price of gas is out of the control of utilities and that its customers have greatly benefitted in the more recent past with the declining cost of gas being passed through quickly.[58]

67. Black Hills concludes that "[w]hile the industry was fully aware of the impending cold weather, the uncertainty of pipeline constraints, supply availability, severity of the weather, and price settlement made the prospect of purchasing fixed price gas highly unlikely at best. Ultimately, had [Black Hills] been able to transact supply purchases ahead of time, those purchases would very likely have been tied to a daily index to mitigate seller's price risk and would not have decreased the overall cost of gas."[59]

68. In contrast to the dissatisfaction with the gas supply market expressed by Public Service and Black Hills, Kinder Morgan, the Houston-based energy infrastructure corporation, reported a nearly $1 billion increase in first quarter 2021 net income attributable primarily related to the February winter storm.[60] Kinder Morgan owns and operates the Colorado Interstate Gas Pipeline (CIG) that transports natural gas from production areas to Colorado utilities other customers in Colorado and Wyoming, owns interests in five storage facilities located in Colorado and Kansas, and operates the High Plains pipeline and Totem Gas Storage

[57] Public Service Situation Report, p. 40.

[58] Public Service Situation Report, p. 40.

[59] Black Hills Situation Report, p. 9.

[60] Kinder Morgan press release, April 21, 2021. https://ir.kindermorgan.com/news/news-details/2021/Kinder-Morgan-Increases-Dividend-3-Percent-and-Raises-2021-Guidance/default.aspx

facility through a 50 percent ownership interest in a joint venture with an affiliate of Xcel Energy.[61]

69. Kinder Morgan's CEO Steve Kean explained that during the February 2021 event: "Our storage assets performed exceptionally well, allowing us to deliver gas into the market throughout the storm. These storage withdrawals, along with gas we purchased before and during the event, enabled us to deliver significant volumes of gas at contractual or prevailing prices. These volumes were directed primarily to serve gas utilities and power plants, including some customers who traditionally find their gas supplies elsewhere."[62] Financial analysts later explained in early June 2021 that the "$1 billion boon to Kinder Morgan Inc.'s balance sheet from February's severe weather enabled the natural gas pipeline giant to offer to buy Stagecoach Gas Services LLC from Crestwood Equity Partners LP and Consolidated Edison Inc."[63]

70. Based on foregoing, we conclude that it is necessary to engage with the gas utilities and other interested stakeholders in a rulemaking proceeding to realign incentives for Colorado gas utilities with respect to dollar-for-dollar recovery of natural gas costs through the GCA rate mechanism. We seek to examine whether a modified GCA framework is required, where utilities are guaranteed less than full recovery of incurred gas costs in exchange for potential profits when savings in gas costs are achieved. A better alignment of incentives appears to be necessary because the guarantee of full cost recovery may have resulted in market

[61] Kinder Morgan website.

[62] Kinder Morgan press release, April 21, 2021: https://ir.kindermorgan.com/news/news-details/2021/Kinder-Morgan-Increases-Dividend-3-Percent-and-Raises-2021-Guidance/default.aspx

[63] "Winter storm windfall put Kinder Morgan in position for Stagecoach purchase," June 2, 2021, S&P Global Market Intelligence.

conditions where the natural gas commodity industry was allowed to fail to deliver natural gas at a reasonable price in part because the utilities lacked sufficient motivation to demand from that industry more responsive pricing products and market mechanisms due to the long-standing assurance that state utility regulators would allow for full cost recovery regardless the price set by the market. An improved alignment in incentives may further cause nation's gas utilities to re-examine the need for capping natural gas commodity prices so that impacts of market failures, such as was experienced in Texas during the same weather event in February 2021, do not cause unnecessary hardship to utility customers in neighboring regions.

71. Accordingly, the Commission proposes modifying the Gas Rules as outlined in Attachments A (in legislative format) and B (without redlining).

**D. Areas of Inquiry**

72. The gas utilities' filings in Proceeding No. 21I-0076EG raise multiple questions surrounding their gas purchasing activities (*i.e.*, how and when they purchase gas for their customers), their management of storage including injections and withdrawals, and their demand side activities (*e.g.*, interruptible services, conservation messages). We seek additional information to reassess the current degree of control the utilities have regarding the incurrence of gas costs.

73. In their comments filed in response to the NOPR and prior to the hearing scheduled by this Decision, we request that that the Colorado gas utilities address the products, market mechanisms, and pricing tools made available to them by the natural gas market and financial institutions. For example, we are concerned that the market fails to provide products that are appropriately "shaped" so that utilities are not forced into acquiring the same amount of

gas for each day of the 4-day weekend even though substantially less gas was known to be required on certain days.

74. As AGA points out and the utilities note in their Situation Reports, storage played an important role in providing service to Colorado customers during the February event and served to mitigate, at least to some extent, the associated price impacts. We therefore request the Colorado gas utilities address in their pre-hearing comments the role of storage relative to their ability to control the costs recovered from ratepayers through the GCA mechanism through storage purchases and withdrawal volumes. We further seek clarification regarding the utility's use of line pack as distinct from the role of storage.

### E. Alternative Forms of Gas Cost Recovery in Other States

75. Utility regulators in other states have established GCA-style rate mechanisms that incorporate cost sharing features and financial performance incentives intended to better align utility and customer interests. The examination of these alternative approaches used in other states may assist Colorado in transitioning to the implementation of modified GCAs that reapportion cost responsibility between the gas utilities and their customers.

76. We seek comment on the potential applicability of the approaches for gas cost recovery described below.

#### 1. Kentucky

77. In Kentucky, state utility regulators permit Louisville Gas and Electric, Columbia Gas, and Atmos to flow less than 100 percent of savings to ratepayers through their gas cost adjustment mechanisms as a gas cost incentive. Atmos' and Columbia Gas' incentive plans provide for sharing, to varying degrees, of gas commodity costs, gas transportation costs, off-system sales margins and capacity release revenues that vary from established benchmarks.

Variances of up to 2 percent are to be allocated 70 percent to ratepayers and 30 percent to shareholders, whereas variances of 2 percent or more are to be shared equally.[64] Louisville Gas and Electric also shares gas commodity cost savings, gas transportation cost savings, and off-system sales margins that vary from established benchmarks. Variances of up to 3 percent are allocated 75 percent to ratepayers and 25 percent to shareholders, whereas variances of 3 percent or more are shared equally. The utility is allowed to retain one-half of capacity release revenues that exceed a certain threshold.[65]

### 2. Maryland

78. Baltimore Gas and Electric Company (BG&E) and Columbia Gas of Maryland (CGM) are subject to incentive mechanisms approved by Maryland state regulators. Under these mechanisms, gas costs above or below benchmark levels are shared with customers. The utility's gas cost adjustments provide for any over- or under-recovery of gas costs for a 12-month period to be credited or charged to customers over the ensuing 12-month period. The gas cost adjustments further recover an administrative charge for the recovery of uncollectible expense related to gas commodity charges.

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[64] Atmos Energy Corporation Gas Cost Adjustment Filing, Case No. 2021-00142, Kentucky Public Service Commission:

https://psc.ky.gov/pscecf/2021-00142/anthony.croissant%40atmosenergy.com/03312021103834/Atmos_Kentucky_GCA_Filing_2021_05.pdf; https://psc.ky.govpscecf/2021-00142/anthony.croissant%40atmosenergy.com/03312021103834/Atmos_Kentucky_GCA_Filing_2021_05_PSC.xlsx

[65] Louisville Gas and Electric Company Electronic Purchased Gas Adjustment Filing, Case No. 2021-00130, Kentucky Public Service Commission:

https://psc.ky.gov/pscecf/2021-00130/andrea.fackler%40lge-ku.com/03312021043613/1_-_LGE_Read_First_Filing_Letter_CN_2021-00130.pdf and supporting calculations spreadsheet https://psc.ky.gov/pscecf/2021-00130/andrea.fackler%40lge-ku.com/03312021043613/4_-_2021_May_GSC_Filing_Exhibits_CN_2021-00130.xlsx .

79. For BG&E, a gas price benchmark is established monthly based on an index of gas prices. Deviations from the benchmark are shared equally with ratepayers. The BG&E mechanism also includes the sharing gains from capacity release and off-system sales. The mechanism further allows for the recovery of costs related to a fixed price gas contract.[66] CGM has a similar provision limited to spot gas purchases in certain months.[67]

### 3. Tennessee

80. Tennessee utility regulators allow that state's gas utilities to recover natural gas commodity costs through automatic adjustment clauses and have weather normalization adjustment clauses in place. These rate mechanisms also include incentives related to gas procurement, capacity release, and off-system sales.

81. Atmos operates in Tennessee subject to a gas procurement incentive and capacity-release incentive related to transportation and storage capacity on upstream pipelines. Under the gas procurement incentive mechanism, commodity costs are compared to a benchmark price index. Net benefits or costs are allocated 75 percent/25percent to customers and shareholders, respectively. Under the capacity management incentive mechanism, Atmos may retain 25 percent of the net benefits associated with the release or utilization of the utility's transportation and storage assets by third parties. In addition, Atmos utilizes a capacity assignment credit rider through which the utility allocates to its customers 90 percent of revenues associated with the

[66] Baltimore Gas and Electric Company June 2021 Gas Commodity Price Filing, June 2, 2021. Maryland Public Service Commission. https://webapp.psc.state.md.us/newIntranet/Maillog/content.cfm?filepath=//Coldfusion/Admin%20Filings/200000-249999/235585/June2021BGEGasCommodity.pdf

[67] Columbia Gas of Maryland Quarterly Purchased Gas Adjustment Filing, March 22, 2021. Maryland Public Service Commission. https://webapp.psc.state.md.us/newIntranet/Maillog/content.cfm?filepath=//Coldfusion/Admin%20Filings/200000-249999/234281/April2021QuarterlyPGA(Filed).pdf

temporary assignment and release of capacity, where the other 10 percent is retained by shareholders.[68]

82. Piedmont Natural Gas (PNG) also operates under a plan that contains incentives related to capacity-management and off-system sales. The net benefits of such activities that vary from a predetermined benchmark are allocated 75 percent to ratepayers and 25 percent to shareholders. PNG's overall incentive gains or losses related to the plan are capped at $1.6 million annually. The plan is reviewed every three years by an independent consultant.[69]

83. Chattanooga Gas is exempt from prudence audits related to its gas procurement activities if the utility's gas commodity costs during a given evaluation period do not exceed a pre-approved benchmark by more than 1 percent.[70]

### 4. Oregon

84. State utility regulators in Oregon instituted an arrangement between the utilities and their customers under which natural gas costs above or below a projected monthly cost per-therm are shared, either 80 percent/20 percent or 90 percent/10 percent customer/utility.[71] After application of the sharing mechanism, a portion of the utility's revenues are credited to a deferred account and returned to ratepayers as part of the utility's subsequent gas cost adjustment filing when earnings are above a specified benchmark return on equity (ROE). The benchmark is set at 150 basis points above the utility's authorized ROE for the 80 percent/20 percent sharing

[68] Atmos Energy Corporation Actual Cost Account (ACA) Filing. Docket 2000105. Tennessee Public Utility Commission. Atmos Energy Corporation Performance Base Ratemaking Filing (PBR). Docket 2100063. Tennessee Public Utility Commission.

[69] See their latest ACA (Actual Cost Adjustment) http://share.tn.gov/tra/orders/2020/2000107.pdf and Annual Incentive Plan http://share.tn.gov/tra/orders/2020/2000106.pdf filings.

[70] http://share.tn.gov/tra/orders/2020/2000112.pdf and PBR http://share.tn.gov/tra/orders/2020/2000113.pdf filings.

[71] See Oregon Public Utilities Commission Order 08-504. https://apps.puc.state.or.us/orders/2008ords/08-504.pdf

provision and 100 basis points above the authorized ROE for the 90 percent/10 percent sharing provision. Out-of-cycle adjustments are permitted if an LDC's gas costs change by 10 percent or more.[72]

85. Oregon's gas cost sharing mechanism is intended to provide an incentive to gas utility to minimize both gas cost and gas cost variability. In addition, the Oregon regulators limit overall gas cost increases are limited to 3 percent of the utility's gross revenues from the previous calendar year and perform annual gas costs prudency reviews.[73]

**5. California**

86. California's investor-owned gas utilities procure natural gas commodity pursuant to a gas cost incentive mechanism (GCIM). In general, the incentive mechanism splits the responsibility of gas costs in varying degrees between ratepayers and the utilities' shareholders above or below a tolerance band around a defined benchmark level. The benchmark is, in simple terms, the average price of 30-day firm spot supplies corresponding to the appropriate supply basins and pipelines as reported in industry publications.[74]

87. As an example, Southern California Gas Company's GCIM dates back to 1994.[75] In June of each year, SoCalGas files an application covering the previous April 1 through Mar 31 "GCIM year." The GCIM program originally consisted of two separate elements: one that measured performance for gas procurement efforts, and the other that measured performance and efficiency of gas storage operations. The GCIM established a benchmark against which to

[72] https://platform.marketintelligence.spglobal.com/web/client?auth=inherit#industry/commissiondetails?ID=4081516&Type=1&State=OR

[73] https://www.oregon.gov/puc/utilities/Documents/What-is-PGA.docx.pdf

[74] https://platform.marketintelligence.spglobal.com/web/client?auth=inherit#industry/commissiondetails?ID=4081517&Type=1&State=CA

[75] https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M340/K159/340159325.PDF

measure the price SoCalGas pays for core and core subscription gas supply. The benchmark was based on a combination of monthly gas price indices published in Natural Gas Intelligence, Inside FERC Gas Market Report, and a New York Mercantile Exchange (NYMEX) component for gas futures. The GCIM included a "tolerance band" to allow SoCalGas to meet objectives related to service reliability and supply security. The approved tolerance band was initially established at 4.5 percent during the first year of the GCIM and 4 percent for the subsequent two years.

88. When establishing the GCIM, the California Public Utilities Commission ordered its Commission Advisory and Compliance Division to conduct an evaluation of the program and to provide regarding the success or failure of the program.[76] The Public Advocates Office of the California Public Utilities Commission (Cal PA), formerly the Office of Ratepayer Advocates (RA), also was given the task of auditing SoCalGas' annual reports on the GCIM. Further, the California commission conducted an analysis of SoCalGas' GCIM in 2001, concluding that gas purchases made by the utility under the GCIM were "definitely far more favorable to rate payers than those made when reasonableness reviews were in effect." The commission's Energy Division further noted that "the GCIM has achieved the Commission's goals for the GCIM," and recommended that the GCIM be continued, explaining that "the GCIM is superior to various alternatives, such as traditional reasonableness reviews, elimination of SoCalGas from the gas procurement function, or inclusion of gas procurement costs in an overall performance based ratemaking mechanism." The GCIM has since been modified and extended. Examples of the changes made through its 26-year evolution included: (1) the elimination of NYMEX as a benchmark index, beginning in Year 8; (2) shareholder rewards were capped at 1.5 percent of the

[76] California Public Utilities Commission D.9403076.

actual annual gas commodity cost; and (3) the sharing bands between ratepayers and shareholders were further modified.[77]

### F. Proposed Rule Changes

89. In this NOPR, we propose to introduce an incentive mechanism within the calculation of the deferred gas costs recovered through the GCA. If the gas utility achieves savings relative to forecast natural gas costs, it would be permitted to retain as earnings a portion of the difference. The responsibility of addressing the payment of costs in excess of forecasts would be shared between ratepayers and utility shareholders.

90. Proposed Rule 4605 (Calculation of Costs Eligible for GCA Recovery) in the rules attached to this Decision:

- Retains the calculation of "current gas cost" in the currently effective rules.
- Retains the provisions governing price volatility risk management costs.
- Retains the existing features of the Account No. 191 with respect to deviations in actual sales versus forecast sales.
- Introduces a means to isolate the difference between actual and forecast gas costs to define cost savings and excess costs.
- Allows credits to Account No. 191 representing savings retained by the utility as earnings (*i.e.*, the positive financial incentive afforded to the utilities).
- Requires debits to Account No. 191 paid for by the utility's shareholders pursuant to an allocation of costs in excess of forecasts (*i.e.*, the negative financial incentive to the utilities). The proposed 90 percent/10 percent allocation of costs between ratepayers and the utility's shareholders derives from financial incentives in place for certain Colorado electric utilities that have developed years of experience in trading in mature markets (*e.g.*, short-term electric energy trades and trading for Renewable Energy Credits). The Colorado gas utilities have engaged in gas commodity purchase and sales transaction for many years.[78]
- Differentiates the share of costs in excess of forecasts borne by the utility by GCA rate area depending on the utility's use of storage in the GCA rate area.

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[77] Application of Southern California Gas Company (U 904 G) Regarding Year 26 (2019-2020) of its Gas Cost Incentive Mechanism, filed June 15, 2020. California Public Utilities Commission. https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M340/K159/340159325.PDF

[78] Decision No. R13-1544, issued December 16, 2013, Proceeding No. 13A-0689E.

- Retains the formula for the calculation of deferred gas costs for inclusion in the GCA except as modified by the credits for savings and debits for costs to Account No. 191.
- Retains the established method for calculating interest on the Account No. 191 deferred balance.

91. We seek comment on the following questions:

- What factors should the Commission consider when establishing a framework for sharing the savings in natural gas costs between the utility and its customers?
- Based on experiences with similar rate incentive mechanisms implemented in Colorado and other states, have there been unintended consequences and how could those be mitigated? For example, is there a concern about the potential for over-investment as a result of the financial incentives? And are there concerns about the dependency of the incentives on forecasts?
- Should uniform savings sharing provisions be adopted by rule in this rulemaking proceeding or should the Commission instead allow for the filing of utility-specific applications for the purpose of establishing the allocation of savings between the utility and its customers?
- What factors should the Commission consider when establishing a framework for sharing costs in excess of forecasts between the utility and its customers?
- Should the calculation of the recoverable deferred gas cost employ one or more "deadbands," or ranges of deviation above or below a baseline such that there is no change from the existing approach to calculating deferred gas cost?
- What details regarding the implementation of these new rules need to be addressed in language set forth in the utility's specific GCA tariff sheets?

92. In addition to the changes proposed in Proposed Rule 4605, we propose other complementary modifications to these GCA-related rules.

93. In Rule 4601 (Definitions), we propose to define a "GCA rate area" to implement different cost sharing provisions in the sections of the utility's service area that are served with storage relative to those section that are not.

94. We also seek comment on whether the definition of "Forecasted gas commodity costs" should be standardized by rule with no or minimal variations in each utility's GCA tariff. The utilities tariffs are presently not standardized as demonstrated below:

- Public Service: Gas Commodity Cost. The total cost of the natural gas commodity that includes each of the following costs, as determined for each month within the GCA Effective Period: (1) the NYMEX Settlement Price as of the first business day of the month prior to the GCA Effective Period, adjusted for the basis differentials between the monthly NYMEX Settlement Price, which is based upon deliveries at the Henry Hub, and the respective indexes applicable to the various areas where the Company purchases its gas supplies, multiplied by the purchase volumes for each corresponding month within the GCA Effective Period; (2) the monthly reservation fees or demand charges payable to gas sellers for making firm quantities of gas available for sale to Company irrespective of the commodity volume actually delivered (gas demand costs); (3) the physical fixed price purchases; (4) appropriate adjustments for storage gas injections and withdrawals; and (5) the gas price management costs.

- Atmos: Current Gas Cost shall be calculated to the nearest Mil ($0.001) per Mcf using the following formula: Current Gas Cost = (Forecasted Gas Commodity Cost + Forecasted Upstream Service

- Black Hills: The Forecasted Gas Commodity Cost Component shall be the system wide average composite unit cost to the Company for purchasing, gathering, treating, and processing of gas or any other services, fees and taxes assessed, under contract or otherwise, multiplied by the Forecasted Gas Purchase Quantity received or to be received as applicable by the Company during the effective GCA period.

- CNG: Forecasted Gas Commodity Cost – The cost of gas commodity, including appropriate adjustments for storage gas injections and withdrawals and exchange gas imbalances, projected to be incurred by the Company during the GCA Effective Period.

95. In Rule 4602 (Schedule of Filings by Utilities), we propose to move all Colorado gas utilities to a quarterly GCA framework for the purpose of more regular reconciliation of Account No. 191 deferred balances and to allow for more responsiveness to unanticipated changes in market prices for natural gas. We also propose to require quarterly GCA changes to be accomplished through advice letter filings made on not less than 30-days' notice.

96. We also introduce into Rule 4602 a new application filing to address the determination of the utility's deferred GCA balance in Account No. 191. We propose this change so that there is a procedural separation between the regular quarterly changes in the GCA so that rates may go into effect generally without disruption while more detailed reviews of "recoverable deferred gas cost" and Account No. 191 balances may be afforded more time and can accommodate potential litigation without impairing GCA cost recovery on a going forward basis.

97. Related modifications are proposed in Rule 4603 (Gas Cost Adjustments) and Rule 4604 (Contents of GCA Applications) to further define the annual and quarterly GCA applications and the new deferred GCA balance applications.

98. We propose no modifications to the rules addressing Gas Purchase Plans, Gas Purchase Reports, and Prudence Reviews.

## G. Conclusion

99. The statutory authority for the rules proposed here is found at §§ 24-4-101 *et seq*.

100. Prior to our issuance of this NOPR, consistent with § 24-4-103(2), C.R.S., the Commission opened Proceeding No. 21M-0130EG for the purpose of commencing its consideration of the impacts of the February 2021 weather event on the revenue requirements and rates of Colorado's investor-owned natural gas utilities. As set forth *supra*, that Proceeding also identified and engaged representative groups that informed the basis for these proposed rules. The participants in Proceeding No. 21M-0130EG are included on the list of persons who receive notification of the NOPR.[79]

[79] Service of this NOPR will be provided to parties in Proceeding No. 21M-0130EG and to filing recipients in Proceeding No. 17R-0569G, the most recent rulemaking addressing the Commission's Gas Rules.

101. The proposed rules in legislative (*i.e.*, strikeout/underline) format (Attachment A) and final format (Attachment B) are available through the Commission's Electronic Filings (E-Filings) System at:

https://www.dora.state.co.us/pls/efi/EFI.Show_Docket?p_session_id=&p_docket_id=21R-0314G

102. The Commission will conduct a remote hearing *en banc* on the proposed rules and related issues on August 26, 2021. The remote public comment will be held using the web-hosted video conferencing service Zoom. Instructions for accessing the remote public comment hearing will be provided in a separate Decision.

103. The Commission encourages interested persons to submit written comments before the hearing scheduled in this matter. In the event interested persons wish to file comments before the hearing, the Commission requests that comments be filed no later than July 23, 2021, that any pre-filed comments responsive to the initial comments be submitted no later than August 6, 2021, and that any changes are proposed in legislative redline format.

104. The Commission prefers comments to be filed in this Proceeding using its E-Filings System at https://www.dora.state.co.us/pls/efi/EFI.homepage. The Commission will consider all submissions, whether oral or written.

105. Interested persons may provide oral comments at the public hearing unless the Commission deems oral presentations unnecessary.

## II. ORDER

### A. The Commission Orders That:

1. This Notice of Proposed Rulemaking including Attachments A and B shall be filed with the Colorado Secretary of State for publication in the July 10, 2021, edition of *The Colorado Register*.

2. A remote hearing on the proposed rules and related matters shall be held as follows:

DATE: August 26, 2021

TIME: 9:00 a.m. until no later than 5:00 p.m.

PLACE: By video conference using Zoom.

3. At the time set for hearing in this matter, interested persons may present comments orally unless the Commission deems oral presentation unnecessary. The Commission prefers and encourages interested persons to pre-file comments in this proceeding (21R-0314G) through its E-Filings System at:

https://www.dora.state.co.us/pls/efi/EFI.homepage.

4. The Commission requests that initial pre-filed comments be submitted no later than July 23, 2021, and that any pre-filed comments responsive to the initial comments be submitted no later than August 6, 2021. The Commission will consider all submissions, whether oral or written.

5. This Decision is effective upon its Mailed Date.

**B. ADOPTED IN COMMISSIONERS' WEEKLY MEETING June 16, 2021.**

(S E A L)

ATTEST: A TRUE COPY

Doug Dean

Doug Dean,
Director

THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF COLORADO

ERIC BLANK

JOHN GAVAN

MEGAN M. GILMAN

Commissioners