BEFORE THE NEBRASKA PUBLIC SERVICE COMMISSION

In the Matter of the Application of Black Hills/Nebraska Gas Utility Company, LLC, d/b/a Black Hills Energy, for Approval of Its Long Term Physical Gas Hedge Contract with Black Hills Utility Holdings, Inc.	)))))	Docket No. NG-0086

POST-HEARING BRIEF OF BLACK HILLS/NEBRASKA GAS UTILITY COMPANY, LLC, DBA BLACK HILLS ENERGY

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Black Hills/Nebraska Gas Utility Company, LLC, d/b/a Black Hills Energy ("Black Hills Energy" or "Company") submits this Post-Hearing Brief as permitted by the Commission in accordance with its Planning Conference Order issued in this proceeding and requested during the hearing in this matter on May 2-3, 2016 (the "Hearing").

I. EXECUTIVE SUMMARY

Black Hills Energy has an obligation to provide natural gas to its Nebraska customers at just and reasonable rates. *See, e.g.,* Neb. Rev. Stat. § 66-1825, § 66-1830. This obligation includes the responsibility to purchase natural gas supplies and manage gas price risk in a prudent manner, and gives the Commission discretion to approve mechanisms to minimize gas price volatility. *See, e.g.,* Neb. Rev. Stat. § 66-1854. Consistent with that statutory obligation, Black Hills Energy, through Black Hills Utility Holdings, Inc. ("BHUH"), has for a number of years prudently supplied natural gas for Nebraska customers using a diversified portfolio of spot market purchases, short-term fixed price contracts, seasonal storage agreements, and short-term financial hedges. This gas purchasing portfolio approach has been successful in providing short-term (*i.e.*, one to two years) price protection for Nebraska customers. However, it is simply not designed to provide protection against gas price volatility or increases over the long-term. The long-term hedging program presented by Black Hills Energy in this proceeding is designed to provide that protection for Black Hills Energy's Nebraska customers.

Even though Black Hills Energy and BHUH purchase natural gas supplies prudently, customer exposure to long-term natural gas price volatility and increases is a real and challenging problem. As is clear from the pre-filed testimony and Hearing testimony in this docket, gas prices (which have recently been at a historic low point) ***will rise***, spot market prices are volatile and ***will continue to be volatile*** in the future (as they have in the past), and hedging with long-term fixed price contracts ***is significantly more expensive*** than the cost of service gas program (the "COSG Program") that is now before the Commission.[1] In fact, the undisputed evidence in the record shows that current production costs are at or above spot gas market prices, which is an unsustainable condition that will force gas prices upward. It is well established that the cost of gas is the largest component of a customer's bill. As such, and as recognized in statute, efforts to stabilize gas costs are warranted. Unless the lack of long-term hedging is addressed, as Black Hills Energy's application in this proceeding does, Nebraska customers will continue to be exposed to 100% of these price risks over the long-term.

Intervenors acknowledge that it is prudent for the Company to pursue hedging efforts to minimize long-term price risk exposure for Nebraska customers. Furthermore, as discussed below, the Public Advocate has conceded that the Commission has the authority to consider and approve the hedging program presented in this proceeding. However, intervenors offer ***no suggested alternative*** and more importantly provide ***no evidence*** that another reasonable hedging option exists to protect against the long-term price risks that the COSG Program is designed to do.

In contrast, the Company has done its homework and looked into the existing market options. Through BHUH, the Company has for several years been investigating options that could provide long-term gas price protection for customers. That investigation has revealed that there is no market option to provide the needed stability and protection at a comparable cost to the COSG Program.

[1] *See, e.g.*, Hearing Ex. 102, Confidential Vancas Direct Testimony, Pages 9-11, 14-15, 17-18; Hearing Ex. 104, Confidential Loomis Direct Testimony, Pages 4-5, 7-8; Hearing Ex. 107, Benton Direct Testimony, Pages 10-11; Hearing Ex. 110, Confidential Ryan Direct Testimony, Pages 4-5, 7, 9-21; Hearing Ex. 111, Revised Confidential Aether Report (JR-1), Page 66; Hearing Ex. 116, Highly Confidential Vancas Rebuttal Testimony, Pages 2, 11, 17-20; Hearing Ex. 123, Ryan Rebuttal Testimony, Pages 4-6, 7-8; Hearing Tr., Page 395, Line 13, to Page 397, Line 19.

Fortunately, a confluence of market conditions has provided a unique and ideal opportunity to address long-term gas supply price volatility by implementing a cost of service gas program similar to those approved in other states, such as Montana, Oregon, Utah, and Wyoming. The similar program used in Wyoming and Utah for decades has saved customers in those states over $1 billion dollars. The fact that market conditions now are ideal to implement the COSG Program for the Company's customers is undisputed. No one disputes that, commensurate with the low-gas-price environment, bankruptcies, liquidations, and restructurings in the upstream oil and gas industry have created an unprecedented opportunity to acquire proven natural gas reserves at very low prices. Because the acquisition cost of these reserves is a significant portion of the costs associated with a cost of service gas program, current reserve prices are ideal for minimizing the cost of the COSG Program for Nebraska customers.

In addition, the undisputed evidence shows that the cost of producing proven reserves – which would effectively serve as Nebraska customers' gas price for that portion of their gas supply hedged under the COSG Program – is not only far more stable than spot market prices, but continues to be further reduced by technological advancements and other efficiencies in the natural gas industry. Thus, there is no dispute that a cost of service gas program would provide the desired price stability. Black Hills Energy's application provides the framework to capture that long-term cost stability at these historically low natural gas market prices.

Taken together, the uncontested evidence shows that the present gas market provides a unique and ideal opportunity to take the first step toward implementing a cost of service gas hedging program.

In this Phase I proceeding, the Company asks that the Commission to take the first step by establishing the scope, structure, and guidelines for the COSG Program, which would allow the

Company to identify the best possible natural gas reserve opportunity to bring to the Commission for review in a Phase II proceeding. Only after both Phase I and Phase II approvals are obtained could the COSG Program be implemented through the acquisition and development of proven reserves and effectively peg 50% of Nebraska customers' gas costs to more stable production costs at a very reasonable price. Indeed, given recent transactions, the Company believes that, if it can act quickly, an acquisition could be found and brought to the Commission in a Phase II proceeding that would have in an all-in COSG Program price for customers in the range of [redacted] per dekatherm ("Dth"). This possible price would be low and stable over the long-term relative to a well-recognized gas market center, the Henry Hub. In fact, the approximate [redacted] per Dth price would be lower than the historic Henry Hub natural gas prices for 83% of the months since January 2000.[2] Customers will save money relative to the market when gas prices rise above the COSG Program price, in addition to benefiting from the program's long-term natural gas price stability. At the same time, the remaining 50% of the Company's natural gas supply portfolio would be based on spot market purchases or shorter-term hedging arrangements that would allow the Company to take advantage of short-term natural gas pricing opportunities for customers.

Intervenors in this proceeding have incorrectly asserted that approval of this Phase I proceeding presents undue risks for customers. This assertion is unsupported and incorrect. As the Company's testimony has made absolutely clear, this Phase I application is a ***no-risk proposition*** for the Commission and customers. It provides a "free" look at what the specific costs and benefits of the COSG Program would be for a specific property through a Phase II proceeding, while preserving the absolute right for the Commission to decide not to move forward. The COSG Program ***cannot be implemented*** and customers would bear ***no costs*** as a

[2] Hearing Ex. 122, Highly Confidential White Rebuttal Testimony, Page 4, Lines 18-19.

result of a Commission approval in this Phase I proceeding. Moreover, this Phase I proceeding is necessary because of the multi-state nature of the COSG Program. Without knowing the structure, scope, or guidelines of the program, Black Hills will not have the necessary information to identify an appropriate proven reserve and develop a proposed drilling plan that could be properly sized for the participating Black Hills utilities. As such, questions about the actual costs (including acquisition costs, drilling and operating costs, and any other cost components), and Nebraska customers' specific allocation of those costs, while entirely appropriate and important, are not the subject of this proceeding, but would absolutely be the subject of the Phase II proceeding. At that time, the Company would also present detailed analyses regarding the anticipated benefits for customers.

The Company has addressed intervenors' concerns and demonstrated, through the evidence in this proceeding (much of which is undisputed), that the COSG Program is a reasonable and prudent approach to providing a long-term hedge against price volatility and price increases. The COSG Program is structured to provide reasonably anticipated cost savings for customers. Moreover, the Commission has the statutory authority not only to approve Phase I, but, if it has questions or concerns regarding the COSG Program, to condition its approval of Phase I on those concerns being addressed. For example, if the Commission believed the language in the COSG Agreement needed to be revised, it could approve the structure, guidelines, and scope of the COSG Program, but require a revised COSG Agreement to be presented as part of the Phase II proceeding.

Neither BHUH nor the Company has undertaken the COSG Program lightly. The program is the result of years of investigation, research, and discussions with commissions, consumer advocates, and other stakeholders in numerous states, and has been developed to address the matters raised in those discussions. If the Company's Application is approved in the Phase I proceeding, the Commission will have the opportunity in a Phase II proceeding to consider a specific proposed transaction, drilling plan, and all necessary cost and benefit data and analysis to determine whether or not the COSG Program should be implemented. If the Commission were to deny the Company's Application in this Phase I proceeding and not even consider a specific proven reserve, and its associated benefits and costs, in a Phase II proceeding, the Commission could miss the opportunity to protect Nebraska customers at a reasonable cost from gas supply cost risk over the long-term. The Company asks the Commission to approve its Application for Phase I of the COSG Program to enable consideration of an actual property in Phase II of the COSG Program.

II. SUMMARY OF PROPOSED FINDINGS OF FACT AND CONCLUSIONS OF LAW

The evidence presented in this proceeding supports the Commission making the following findings of fact and conclusions of law:

- The Commission may modify a jurisdictional utility's gas supply cost adjustment rate schedule under procedures specified for setting rates by order of the Commission pursuant to Neb. Rev. Stat. § 66-1854(3);

- The Commission possesses statutory authority to establish alternative rate mechanisms when such mechanisms modify a utility's recovery of gas supply costs pursuant to Neb. Rev. Stat. § 66-1854(6);

- Gas supply costs may include costs related to gas price volatility risk management activities, the costs of instruments utilized to hedge against gas price volatility, if prudent, and other relevant factors pursuant to Neb. Rev. Stat. § 66-1854(1);

- Approval of this Phase I application for Black Hills Energy's COSG Program does not obligate the Commission to approve a specific property or implementation of the COSG Program in a Phase II proceeding;

- The evidence in the record demonstrates that (i) market gas prices are volatile and are more likely to rise than decrease or stay the same over the long term, and (ii) production costs are far more stable than market gas prices;

- Black Hills Energy has met its burden of proof related to Phase I of the proposed COSG Program in this proceeding pursuant to Neb. Rev. Stat. § 66-1854(1), and it is prudent for Black Hills Energy to enter into the COSG Agreement, 50% of its gas supply should be hedged under the COSG Program, and the COSG Program does not violate any ring-fencing provisions applicable to Black Hills Energy; and

- The Commission authorizes Black Hills Energy to implement and thereafter modify gas supply cost adjustment rate schedules as proposed in its COSG Program where such costs reflect increases or decreases in the cost of the utility’s gas supply pursuant to Neb. Rev. Stat. § 66-1854(1), recognizing that the modified rate schedules will have no impact on customer rates unless and until the Commission approves implementation of the COSG Program in a Phase II proceeding.

III. APPLICABLE LEGAL STANDARDS

The legal standards applicable to the Company’s Application are clear and straight-forward. Neb. Rev. Stat. § 66-1854 provides the Commission with broad discretion to consider and approve measures to manage gas price volatility and to modify the Gas Cost Adjustment (“GCA”) schedules to incorporate gas supply costs that include hedging costs or costs associated with managing price volatility risk. That provision states, in relevant part:

> “(1) The commission shall allow jurisdictional utilities to implement and thereafter modify gas supply cost adjustment rate schedules that reflect increases or decreases in the cost of the utility's gas supply such as (a) federally regulated wholesale rates for energy delivered through interstate facilities, (b) direct costs for natural gas delivered, or (c) costs for fuel used in the manufacture of gas. ***Such costs may, in the discretion of the commission, include costs related to gas price volatility risk management activities, the costs of financial instruments purchased to hedge against gas price volatility, if prudent, and other relevant factors.*** Gas supply cost adjustment rate schedules in effect on May 31, 2003, shall continue in effect until changed pursuant to the provisions of the State Natural Gas Regulation Act. In each such proceeding the burden of proof shall be upon the utility.”

(Emphasis added). The Public Advocate has acknowledged in this proceeding that, under this provision, the Commission has the authority and discretion “to consider financial hedging management and hedge devices as part of the purchase gas adjustment clause," including the COSG Program.[3]

Furthermore, Neb. Rev. Stat. § 66-1804 emphasizes the Commission's broad powers under the State Natural Gas Regulation Act ("SNGRA") to consider and approve programs like the COSG Program:

> "(1) ***The commission shall have full power, authority, and jurisdiction to regulate natural gas public utilities and may do all things necessary and convenient for the exercise of such power, authority, and jurisdiction.*** Except as provided in the Nebraska Natural Gas Pipeline Safety Act of 1969, and notwithstanding any other provision of law, such power, authority, and jurisdiction shall extend to, but not be limited to, all matters encompassed within the State Natural Gas Regulation Act."
>
> "(2) The State Natural Gas Regulation Act and all grants of power, authority, and jurisdiction in the act made to the commission shall be liberally construed, ***and all incidental powers necessary to carry into effect the provisions of the act are expressly granted to and conferred upon the commission***."

(Emphases added). Neb. Rev. Stat. § 66-1807 also grants the Commission authority to approve the COSG Program:

> "Except as otherwise provided in the State Natural Gas Regulation Act, all orders, rules, regulations, practices, services, rates, charges, classifications, and tolls fixed by the commission shall be prima facie reasonable unless or until changed or modified by the commission or in pursuance of proceedings instituted in court as provided in the act."

Decisions in other states denying reserve acquisitions or programs that turn on those states' particular statutes and the particulars of those proceedings are irrelevant to this Nebraska proceeding.[4] Furthermore, other states have approved cost of service gas programs that are similar to the COSG Program.[5]

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[3] Hearing Tr., Page 424, Lines 1-5.

[4] Although the Florida Supreme Court acknowledged that Florida Power & Light's gas reserves program "may be a good idea," it held that a Florida electric utility's ***direct*** ownership of gas reserves fell "outside the purview of an electric utility as defined by the [Florida] Legislature" and that the utility itself could not earn a return on gas purchases. *Citizens of the State of Florida vs. Art Graham, et al.*, __ So. 3d __ (Fla. May 19, 2016). In contrast, the

Having conceded that the Commission has authority to review the COSG Program, the Public Advocate nevertheless argues that the Company's request for a prudence determination before implementation of the COSG Program should be of concern for two reasons. First, the Public Advocate argues that the Commission is being asked to determine the reasonableness of expenses in this matter. That is incorrect. As explained repeatedly by the Company and as discussed in this brief, this Phase I proceeding does not seek approval of any amounts or changes in rates. Rather, it seeks approval of the scope, structure and guidelines of a long-term hedging program. Approval of costs and rate changes will only occur in Phase II or thereafter.

Similarly, concern has been raised that this Commission cannot make a prudence determination on this Phase I Application. The Public Advocate has not cited to any legal authority to support its claim that a prudence determination on the structure, design and scope of a program is not appropriate.[6] Indeed, Neb. Rev. Stat. § 66-1808 specifically contemplates as much. It states, in pertinent part:

> "(2) Unless the commission otherwise orders, ***no jurisdictional utility shall make effective any changed rate or any term or condition of service pertaining to the service or rates of such utility, except by filing the same with the commission at least thirty days prior to the proposed effective date*** . . . . Any such proposed change shall be shown by filing with the commission a schedule showing the changes, and such changes shall be plainly indicated by proper reference marks in amendments or supplements to existing tariffs, schedules, or classifications, or in new issues thereof."

Company is not an electric utility, it will not directly own gas reserves, it will not earn a return, and Florida statutes are wholly irrelevant here.

The Virginia State Corporation Commission denied Washington Gas Light's cost of service gas program because customers would bear all the risks and the percentage of gas supply to be hedged exceeded the percentage authorized by the Virginia Legislature. Hearing Ex. 301, Exhibit SB-4, *Order on Application of Washington Gas Light Company for Approval of a Natural Gas Supply Investment Plan* (Case No. PUE-2015-00055). In contrast, Nebraska customers would not bear all the risks of the COSG Program, the Company is asking the Commission in this proceeding to determine the percentage of its gas supply to be hedged under the program, and Virginia statutes are wholly irrelevant here.

[5] Hearing Ex. 102, Confidential Vancas Direct Testimony, Page 12, Lines 7-19; Page 12, Lines 11-16.

[6] *See* Hearing Tr., Page 36, Line 22 to Page 41, Line 14; Page 419, Line 2 to Page 426, Line 24.

(Emphases added). Moreover, no case law has been found indicating otherwise. *KN Energy, Inc. v. Cities of Alliance and Oshkosh*, 266 Neb. 882, 607 N.W. 2d 319 (2003) is not to the contrary. That case addressed an after-the-fact prudence challenge to a ***contract that had already been implemented***. In that context, the Nebraska Supreme Court held that, in assessing the prudence of utility ***activities that have already occurred***, the analysis should not be made with the benefit of hindsight, but should look at the circumstances at the time the activity was undertaken. *Id.* at 325. In this case, the Company has brought the COSG Program for Commission approval and has asked the Commission to determine that, given current circumstances approval of this Phase I proceeding is prudent.

Constellation NewEnergy Gas ("CNEG") argued during the Hearing (albeit without any authority) that the Commission should apply a strict scrutiny standard to its review because there will be an allocation of costs between Black Hills' affiliates.[7] However, Nebraska law does not support this claim. The Commission and Nebraska Courts have already ruled on how cost allocations between affiliate entities of Black Hills Energy are to be assessed and under what standard. In addition, there will be a review in Phase II of all costs and, if Phase II is approved, any program costs will be reviewed on an annual basis by the Accounting Monitor and submitted to the Commission through GCA filings.[8] The Commission can and should reject any arguments that the COSG Program in this Phase I proceeding runs afoul of any affiliate cost allocation requirements.

The Company's Application is consistent with the SNGRA and Nebraska law, as they provide the Commission with authority to review and approve the scope, structure, and guidelines

[7] Hearing Tr., Page 48, Lines 14-16; Page 435, Lines 1-10.

[8] Furthermore, Commission Rules 001.01A1, 001.01A2, and 005.07 provide for exceptions as to the burden of proof for costs between "shared resources" affiliates, which would include the relationships presented by the Company under the COSG Program. 291 Neb. Admin. Code, Ch. 9, Rules 001.01A1, 001.01A2, and 005.07.

of the COSG Program, and the cost formulas like a GCA mechanism that will provide for "just and reasonable" rates upon approval of program implementation in a Phase II proceeding.[9]

IV. SUMMARY OF INTERVENORS' CONTENTIONS AND CASE

The following summary is a recitation of the primary arguments raised by intervenors. The Company does not agree with these arguments and addresses them in Section V of this brief.

A. Summary of the Public Advocate's Contentions and Case.

The Public Advocate has recommended that the Commission disapprove the Company's application in this Phase I proceeding. The Public Advocate's recommendation is based upon the following arguments:

- The COSG Program allegedly shifts the risk of excessive costs to customers and will allow an unregulated business affiliate of the Company ("COSGCO") to recover all of the associated program costs from customers, as well as earn a guaranteed return on equity ("ROE");[10]
- The COSG Program's use of the average ROE for all electric and gas utility rate cases in the Regulatory Research Associates ("RRA") report is unreasonable;[11]
- The requested 40/60 debt/equity ratio overstates the return to Black Hills;[12]
- Utilities participating in the COSG Program will "be left to shoulder the burden of the costs that would have been allocated to and paid for by the other operating company(ies) not receiving approval for the COSG program";[13]

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[9] For example, Neb. Rev. Stat. § 66-1855, provides that the Commission may set rates within bands even though the exact rate at the time of approval may not be known: "The commission may authorize, consistent with general regulatory principles, including, but not limited to (1) banded rates with a minimum and maximum rate that allows the jurisdictional utility to offer ratepayers rates within the rate band for the purpose of attracting additional natural gas service demand or to retain such demand, (2) mechanisms for the determination of rates by negotiation, and (3) customer choice and other programs to be offered by a natural gas public utility to unbundle one or more elements of the service provided by the utility."

[10] Hearing Ex. 200, McGarry Direct Testimony, Page 7, Lines 3-5; Hearing Tr., Page 420, Line 3 to Page 421, Line 11.

[11] Hearing Ex. 200, McGarry Direct Testimony, Page 7, Lines 6-11.

[12] *Id.*, Lines 12-13.

[13] *Id.*, Page 8, Lines 9-14.

- The COSG Program would lock customers into paying program costs for 20 to 30 years;[14]
- The termination provision of the COSG Agreement would not allow the Company to terminate its participation and sell its interest unless (i) the Commission orders the termination; (ii) all of the other participating utilities consent to the sale; and (iii) the interest can be sold;[15]
- The timeframes for the Hydrocarbon Monitor's review of proposed acquisitions, and the timeframes for Commission review of acquisition and drilling plans are insufficient; and[16]
- The Monitors would not be sufficiently independent.[17]

B. Summary of Marketer-Intervenors' Contentions and Case.

The real concern held by marketer-intervenors is that a successful COSG Program would affect their own bottom line profits from Nebraska customers. While the Commission granted the marketer-intervenors' motions to intervene in this proceeding, in doing so, the Commission noted that their involvement would only be given the weight to which it should properly be afforded given the fact that (i) they are competitors of the Company with a self-interest in the outcome of this proceeding, and (ii) it is undisputed that the COSG Program ***will not*** have any impact upon transportation customers in Nebraska or the Choice Gas Program. The Public Alliance for Community Energy ("ACE") has been candid about its motive. Although ACE acknowledges that "there would be no immediate impact to ACE or its customers from approval of this application," it nevertheless has stated in pre-filed testimony that:

> "[T]here is a concern that this transaction is a stepping stone for subsequent actions which could significantly impact the continuation of the Nebraska Choice Gas Program and cause harm to ACE, its municipal members and its customers."[18]

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[14] Hearing Tr., Page 425, Lines 14-16.
[15] *Id.*, Page 423, Lines 6-25; Hearing Ex. 200, McGarry Direct Testimony, Page 8, Lines 15-17.
[16] Hearing Ex. 200, McGarry Direct Testimony, Page 7, Lines 14-19.
[17] *Id.*, Page 7, Line 20 to Page 8, Line 3.
[18] Hearing Ex. 400, Ackland Direct Testimony, Page 8, Lines 9-12.

CNEG has expressed similar concerns.[19] CNEG's apparent motive is to kill consideration of the COSG Program before the governing commissions can consider a specific property and its associated benefits to customers in a Phase II proceeding. To accomplish their business goals, these intervenors make the following contentions:

1. ACE/Nebraska Municipal Power Pool ("NMPP")

ACE and the NMPP request disapproval of the Company's application in this Phase I proceeding. Their request is based upon the following arguments:

- The COSG Program could result in substantial costs that would be borne by customers;[20]
- The COSG Program is lengthy and could result in substantial exit costs if it is determined that termination of the program is in customers' best interests;[21] and
- While the COSG Program will have no immediate impact on the Nebraska Choice Gas Program, "there is a concern that this transaction is a stepping stone for subsequent actions which could significantly impact the continuation of the Nebraska Choice Gas Program and cause harm"[22] to municipal members of ACE or NMPP, because if customers chose the COSG Program over the Choice Gas Program, ACE or NMPP would have less earnings.

2. CNEG

CNEG also requests that the Commission disapprove the Company's application in this Phase I proceeding. That request is based upon the following arguments:

- The COSG Program will allow COSGCO, an unregulated business affiliate, to recover all of the associated program costs from customers;[23]
- The COSG Program transfers risk to customers;[24]
- If other states do not participate in the COSG Program, the burden on Nebraska customers

[19] Hearing Ex. 302, Sorenson Direct Testimony, Page 7, Lines 18-21.
[20] Hearing Ex. 400, Ackland Direct Testimony, Page 6, Lines 15-17.
[21] *Id.*, Page 8, Lines 3-6.
[22] *Id.*, Lines 9-12; Hearing Tr., Page 427, Lines 5-15.
[23] Hearing Tr., Page 47, Lines 20-22.
[24] Hearing Ex. 301, Bennett Direct Testimony, Pages 8-11.

will increase;[25]

- The COSG Program is an effort to salvage Black Hills' exploration and production business (Black Hills Exploration & Production ("BHEP"));[26]

- The COSG Program is unnecessary because BHEP could sell its gas long-term to Black Hills' utilities;[27]

- The Monitors are insufficient because they will not have access to adequate information and will not have the freedom to do the necessary work;[28]

- The termination provision of the COSG Agreement does not allow an exit from the COSG Program;[29]

- The COSG Program lacks definition on what customer classes will be included and customers' ability to transfer between groups; and[30]

- The COSG Program is anti-competitive in that it could restrict customer freedom to select a preferred provider and makes them captive to a monopoly service for years to come.[31]

Again, the Company does not agree with intervenors' arguments and, as described in this brief, the record does not support them.

V. ARGUMENT

A. Natural Gas Prices Are Volatile, and the Record Demonstrates That Prices Are at or Below Production Costs and Will Increase over the Long-Term.

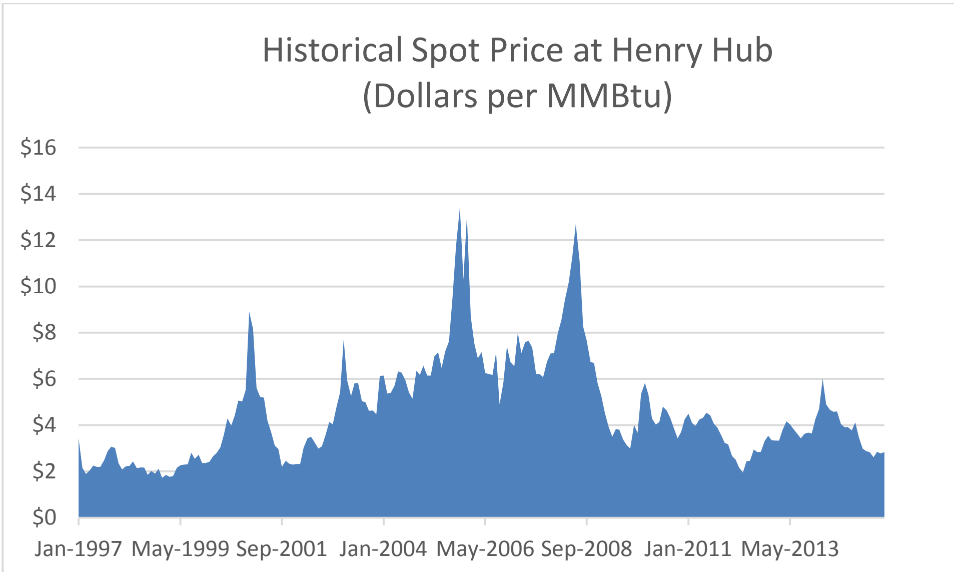
There is no disagreement between the parties on two essential points: (1) gas prices are volatile, and (2) current prices are at or below the production cost and, as such, will increase.

1. Gas Prices Are Volatile.

The undisputed evidence shows that spot market gas prices are subject to significant change and, in that respect, are volatile. The Company was the only party to offer any evidence

[25] Hearing Tr., Page 430, Lines 23-24.
[26] Hearing Ex. 301, Bennett Direct Testimony, Page 16, Line 8 to Page 19, Line 3; Hearing Tr., Page 46, Line 4 to Page 47, Line 12.
[27] Hearing Tr., Page 432, Lines 14-23.
[28] *Id.*, Page 48, Line 19 to Page 49, Line 13.
[29] *Id.*, Page 49, Line 14 to Page 50, Line 17.
[30] Hearing Ex. 302, Sorenson Direct Testimony, Page 5, Lines 5-8.
[31] *Id.*, Lines 14-19.

concerning the volatility of gas prices. For example, in Figure 1 to his direct testimony, Mr. Loomis provided an 18-year historical gas price summary showing the spot market prices at the Henry Hub trading point from 1997 to 2015 (depicted below).



This summary demonstrates significant volatility in natural gas prices, including during the period since the shale revolution began. When questioned about this figure, Mr. McGarry agreed that natural gas prices are volatile and that the volatility has continued despite the shale revolution.[32] In addition, Ms. Ryan of Aether Advisors, the only natural gas hedging expert in this proceeding, assessed historical gas prices and looked at gas price forecasts to show that gas prices have been volatile and are expected to continue to be so in the future.[33] Indeed, intervenor witnesses agree with Ms. Ryan.[34] While intervenors tried to claim during the Hearing that gas prices have become more stable in recent years, they did not submit any actual evidence demonstrating this and, in fact, they could not have because that assertion is not borne out in the data. As the figure

[32] Hearing Tr., Page 395, Line 13, to Page 397, Line 19.
[33] Hearing Ex. 111, Revised Confidential Aether Report (JR-1), Page 66; Hearing Ex. 123, Ryan Rebuttal Testimony, Pages 7-8.
[34] Hearing Tr., Page 397, Lines 9-13 (McGarry Cross-Examination); Hearing Ex. 500, Harms Direct Testimony, Page 6, Lines 5-9.

above demonstrates, prices from 2011 to 2014 were far ***more volatile*** than during the period from 1997 to 2000 before the shale revolution. Any claim that natural gas prices will be less volatile in the future than they have been in the past is purely speculative.

2. Market Fundamentals Indicate that Gas Prices Are Far More Likely to Rise.

While no one in the proceeding is claiming to have foreknowledge regarding precisely when natural gas prices will change in the future and by how much, all of the available evidence in the record demonstrates that gas prices are far more likely to rise over the long-term than to fall or remain constant. As Ms. Ryan noted after her extensive review of the market, natural gas prices are currently "below producers' full cost of production . . . ."[35] Indeed, in her report, she demonstrates that, even in some of the lowest-cost shale gas resources, break-even prices in 2014 ranged between [redacted] which is above the level of current natural gas prices.[36] Simple economics tells us that producers cannot produce gas at a loss for very long. This is, in substantial part, why an unprecedented number of gas producers have declared bankruptcy, liquidated assets, and/or restructured their businesses in the past two years.[37] For that reason, and others that Ms. Ryan considered as part of her comprehensive review of the market (*e.g.*, demand drivers, production economics, etc.), she concluded that market prices are far more likely to rise than to fall or remain constant.[38] The Public Advocate and its witness Mr. McGarry agreed that they also expect gas prices to rise, and no other intervenor challenged that viewpoint.[39] Indeed, this is reflected in the long-term price forecasts prepared by independent third parties.[40] Such

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[35] Hearing Ex. 123, Ryan Rebuttal Testimony, Page 5, Lines 1-2.
[36] Hearing Ex. 111, Revised Confidential Aether Report (JR-1), Page 72.
[37] Hearing Ex. 123, Ryan Rebuttal Testimony, Page 5, Lines 6-18; Hearing Ex. 136, Response to Request No. PA-60, Attachment 60l.
[38] Hearing Ex. 110, Confidential Ryan Direct Testimony, Page 19, Line 14; Hearing Ex. 123, Ryan Rebuttal Testimony, Page 5, Line 4.
[39] Hearing Tr., Page 38, Lines 4-8; Page 39, Lines 4-5; Page 406, Lines 4-8.
[40] Hearing Ex. 104, Confidential Loomis Direct Testimony, Page 12, Line 17 to Page 15, Line 2.

forecasts are regularly used in the utility industry to make long-term resource decisions.[41] Therefore, the record before the Commission demonstrates not only that are gas prices volatile and expected to continue to be so, but also that gas prices are far more likely to rise than to fall or remain where they are today.

B. Customers Are Exposed to 100% of the Risk of Long-Term Gas Price Increases and Volatility, and the Implementation of a Long-Term Hedging Strategy to Minimize That Risk Is Prudent.

The evidence of the long-term gas price risks borne by Nebraska customers is undisputed in this proceeding. Even though the Company is presently and will continue purchasing its gas supply prudently, its current natural gas portfolio and prudent purchase plan is designed to address gas price risks in the short-term. It does not protect against price volatility that extends out beyond the near-term. Currently, customers bear 100% of all the natural gas price risk. Outside of the current hedging window of one or two winters, customers are entirely exposed to rate volatility associated with gas market price volatility. Even though gas will be purchased in the future in a prudent manner, if natural gas market prices increase over the long-term, customers will pay for those increases. Presently, those prudently incurred prices are simply passed through the GCA to customers, who are then required to pay the prudently incurred cost of gas.[42] Those customer costs, over the long-term, reflect all of the production, processing, transportation, and marketing costs to produce the gas and bring it to market, including an unregulated rate of return for the market participants available in the oil and gas industry.[43]

Because of this risk exposure, no party disputes that the implementation of a long-term hedging strategy to provide price stability and to mitigate the effects of price increases is

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[41] Hearing Tr., Page 297, Line 4 to Page 298, Line 6.
[42] Hearing Ex. 110, Confidential Ryan Direct Testimony, Page 4, Lines 7-16; Hearing Ex. 116, Highly Confidential Vancas Rebuttal Testimony, Page 15, Lines 14-17.
[43] Hearing Ex. 116, Highly Confidential Vancas Rebuttal Testimony, Page 15, Line 21 to Page 16, Line 11.

reasonable and prudent. Ms. Ryan conducted a complete assessment of BHUH's hedging strategy for each of its utilities and provided recommendations based on that assessment. Ms. Ryan's analysis was not challenged by the other parties at the Hearing. She concluded that, while BHUH's current hedging strategy is "well-structured and very transparent" and provides short-term protection, it does not address long-term risks, and BHUH should "expand the time horizon of the hedging program and increase the percentage hedged."[44] Specifically, she recommended "an integrated approach to incorporate long-term hedging with BHUH's current hedging strategy."[45] By doing so, she stated, "the commodity cost of gas would be smoother over time, offering more rate stability for customers."[46] Furthermore, she concluded that "[t]he two gas supply objectives to provide reasonably priced natural gas and mitigate price volatility would be well met through the acquisition and production of reserves."[47] Finally, as it relates to the COSG Program, Ms. Ryan concluded that the program is consistent with her recommendations and that the "COSG Program offers greater rate stability over the long term" than the Company's current short-term hedging practices.[48]

To assess potential alternatives, BHUH sent out requests for proposal for long-term fixed-price hedging contracts.[49] BHUH only received one response for a 20-year proposal, and the proposed cost exceeded [redacted] per Dth.[50] The pricing for other options was also unreasonable in that it was non-binding and dependent upon terms and conditions that could alter the price, [redacted]

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[44] Hearing Ex. 110, Confidential Ryan Direct Testimony, Page 6, Line 6; Page 7, Lines 1-2.
[45] *Id.*, Page 30, Lines 16-17.
[46] *Id.*, Page 7, Lines 7-9.
[47] *Id.*, Page 30, Lines 20-22.
[48] *Id.*, Page 7, Lines 18-20.
[49] Hearing Ex. 102, Confidential Vancas Direct Testimony, Page 9, Lines 15-20; Hearing Ex. 104, Confidential Loomis Direct Testimony, Page 8, Lines 1-4.
[50] Hearing Ex. 104, Confidential Loomis Direct Testimony, Page 8, Lines 4-6.

[redacted][51] and would have carried material counterparty default risk, no volumetric flexibility, and potentially large collateral posting requirements.

Neither the Public Advocate nor the marketer-intervenors challenged Ms. Ryan's assessment or conclusions and none of them provided evidence of other, reasonable options to provide long-term hedging. Mr. McGarry conceded that a prudent utility should undertake measures to avoid or help customers minimize exposure to price volatility and increases.[52] He also conceded that he conducted no hedging analysis and had no basis to contest Ms. Ryan's analysis, conclusions, or recommendations.[53] Mr. McGarry further acknowledged that implementing a longer-term hedging approach is prudent.[54] He also (i) admitted that he had no evidence that there are other hedging options offering similar long-term protection or what the prices of those options, if any, would be, and (ii) confirmed that he had no evidence "that a medium-term or longer-term hedging available in the market is better" than the COSG Program.[55]

Thus, the undisputed evidence shows that the implementation of a long-term hedging strategy for the Company is prudent. It also establishes that there are no other comparable long-term hedging options available in the market within a reasonable price range. Finally, the evidence shows that the acquisition and development of reserves, particularly in the absence of any evidence of better alternatives, is a reasonable and prudent mechanism for providing needed long-term price stability.

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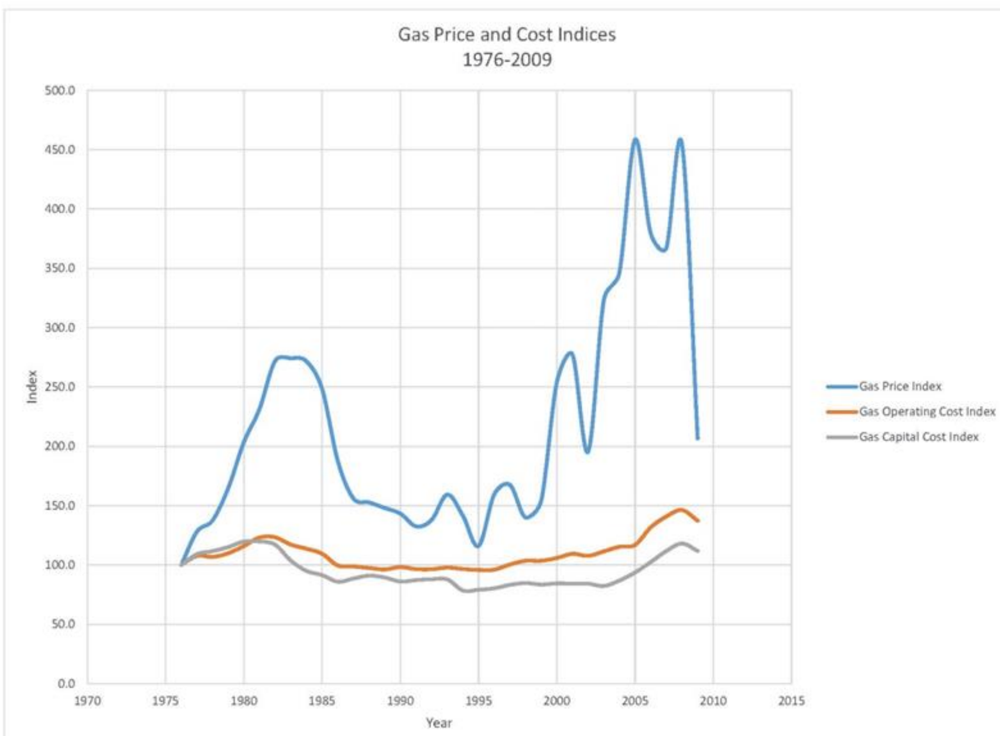
[51] *Id.*, Page 8, Lines 7-12.
[52] Hearing Tr., Page 402, Lines 8-11; Page 422, Lines 17-20.
[53] *Id.*, Page 400, Lines 1-18; Page 401, Lines 8-22.
[54] *Id.*, Page 402, Lines 8-11.
[55] *Id.*, Page 400, Lines 6-18.

C. Production Costs Are Far More Stable Than Volatile Market Prices.

The primary benefit of a cost of service gas program is its ability to provide greater rate stability than market prices by pegging customer gas costs to stable production costs instead of being tied to ever-changing market prices. In this proceeding, the Company has clearly established, and intervenors have not challenged, the fact that production costs under the COSG Program would be far more stable than spot market prices. Specifically, Mr. Benton, who has more than 35 years' experience in the oil and gas industry, testified that production costs are markedly more stable than market prices, particularly over the long-term.[56] He emphasized the magnitude of the difference by comparing EIA data from 1976 through 2009 (the last year when the information is available) for both market prices and production costs in the following figure:[57]



[56] Hearing Ex. 107, Benton Direct Testimony, Page 10, Line 2 to Page 11, Line 1; Hearing Tr., Page 182, Line 23 to Page 183, Line 1 ("I've worked in this industry for 35 years and can state from experience that costs will be stable and predictable in [a] developed field with proven reserves.").

[57] Hearing Ex. 107, Benton Direct Testimony, Page 10, Line 2 to Page 11, Line 1.

In discussing this figure during the Hearing, Mr. Benton explained that the production cost line in the graph above includes exploratory wells and, if those wells were removed from the data (as exploration wells would not be included in the COSG Program), production costs would be even more stable.[58] Furthermore, addressing proved developed producing reserves, he added that, because of the nature of those reserves, production costs are easy to predict because you have existing wells, an established drilling history, and existing infrastructure.[59] The record demonstrates that gas prices have been and continue to be far more volatile than production costs, which have moved only minimally within a narrow band.

While intervenors made a half-hearted effort to press on this issue by noting the obvious point that there will always be some amount of variability in costs, Mr. Benton testified:

> "[T]he COSG Program requires properties considered for inclusion in the program to have significant proven reserves. Drilling and operating costs within a field containing significant proven reserves tend to be relatively predictable and stable. . . . . [W]hile drilling and operating costs could vary some, from forecasted estimates, it would be unlikely that the variance would be material."[60]

For example, he explained that, absent inflation, any variability would be "no more than plus or minus 10 percent."[61] Because operating expenses for proved producing reserves range between approximately $0.50 and $1.00 per MCF (depending on the field), Mr. Benton calculated the potential variance to be ***between five to ten cents*** per MCF – a very small number indeed.[62] Because of Black Hills Energy's confidence that production costs will vary only minimally, it has indicated in its rebuttal testimony that it would not be opposed to establish a cap on certain

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[58] Hearing Tr., Page 238, Lines 3-8.
[59] *Id.*, Page 238, Line 14 to Page 239, Line 6.
[60] Hearing Ex. 119, Benton Rebuttal Testimony, Page 2, Lines 6-9, 12-13.
[61] Hearing Tr., Page 239, Line 25 to Page 240, Line 1.
[62] *Id.*, Page 241, Lines 11-21.

production costs in the Phase II proceeding.[63]

Intervenors have presented no evidence to contradict Mr. Benton's testimony. In fact, Mr. McGarry acknowledged that he does not challenge Mr. Benton's evidence that production costs are far more stable than market prices and, for proven reserves, are highly predictable.[64] Therefore, while intervenors have tried to play the alarmist about potential cost variations in production costs under the COSG Program, their unsupported arguments are simply a baseless exaggeration for effect, attempt to invoke the Commission's fears, and should be given no weight. The only evidence in the record relating to the stability or predictability of production costs is Mr. Benton's unchallenged testimony and the Public Advocate's acknowledgement of that fact.

D. The Undisputed Evidence Demonstrates That Now Is an Ideal Time to Implement a Cost of Service Gas Hedging Program.

Also critical to the Commission's assessment of the Company's Application is the convergence of a set of market factors that make now an ideal time to implement the COSG Program. The evidence in the record irrefutably establishes that reserve acquisition costs are at an historic low point, providing the COSG Program, if implemented soon, with the opportunity to acquire proven reserves in a range that would provide customers with a stable price for the long-term at or very near [redacted] per Dth. Furthermore, as described below, even a conservative estimate assuming an all-in cost above [redacted] per Dth demonstrates that the cost of hedging under the COSG Program is more than reasonable.

1. <u>Reserves Can Be Acquired at Historically Low Prices and Make Possible Cost of Service Rates at or Near [redacted] Per Dekatherm</u>.

It is well established that the cost of gas is the largest component of a customer's bill. As such, and as recognized in statute, efforts to stabilize gas costs are warranted. As noted above, a

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63 Hearing Ex. 116, Highly Confidential Vancas Rebuttal Testimony, Page 8, Line 16 to Page 9, Line 2.

64 Hearing Tr., Page 395, Line 8 to Page 397, Line 13; Page 402, Lines 12-21.

significant expense associated with the COSG Program is the cost of acquiring proven reserves. Accordingly, if this acquisition cost can be minimized, the overall cost of gas under the COSG Program will be similarly minimized, which benefits Nebraska customers. In this proceeding, the Company has provided substantial (and again unrefuted) evidence that gas reserves can be acquired in the present market at some of the lowest prices (adjusted for inflation) in the modern era of gas production. For example, in his rebuttal testimony, Mr. Vancas testified:

> "The E&P industry is experiencing a profound, prolonged disruption due to the current, unsustainably low price environment. This is causing many E&P companies severe financial distress, and distressed companies are selling assets at below market rates. This may create a great opportunity for COSGCO to purchase gas reserves from distressed third-party sellers, willing to sell properties at prices lower than what BHEP would sell its Mancos asset. The Company's rebuttal witness Mr. White addresses the Company's anticipated plans for pursuing producing assets and related proven reserves at a cost of approximately [redacted]/ dekatherm or better (based on current market prices for natural gas) for implementing the COSG Program in a Phase II application."[65]

The Company also produced dozens of publications, reports, and market studies confirming the rise in bankruptcies and the resulting liquidations of reserves by distressed companies at very favorable prices.[66] In his rebuttal testimony, Mr. White stated:

> "With the current financial stress being experienced by the oil and gas industry, Black Hills believes that it is possible to acquire gas production and related proven reserves at short and long-run costs that would be attractive to our retail natural gas customers. If the Commission approves this Phase I application, Black Hills intends, based on current market conditions, to pursue an acquisition to initiate the COSG Program that meets the approved criteria and that has an expected short and long-run total cost of service price for customers of [redacted] per dekatherm or better. Considering relevant historical prices for natural gas, this should be attractive and beneficial to customers."[67]

Mr. Vancas and Mr. Benton also reiterated during the Hearing how the present market conditions

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[65] Hearing Ex. 116, Highly Confidential Vancas Rebuttal Testimony, Page 11, Lines 5-14.

[66] Hearing Ex. 136, Response to Request No. PA-60, Attachments 60a to 60oo; Hearing Ex. 140, Response to Request No. PA-75, Attachments 75a to 75c.

[67] Hearing Ex. 122, Highly Confidential White Rebuttal Testimony, Page 3, Line 20 to Page 4, Line 5.

are causing producers to sell proven reserves at very attractive prices.[68] No intervenor challenged that testimony, and the record is devoid of any evidence to the contrary.

The estimated [redacted] per Dth all-in price under the COSG Program is important because it demonstrates the benefit of the COSG Program and explains the urgency to implement the COSG Program by establishing the parameters and guidelines for Phase II. As noted in Mr. White's rebuttal testimony, and in particular his Exhibit KDW-1, the average gas market price from 2009 to 2015 (during the shale revolution) was $3.69 per Dth.[69] Had the COSG Program been in effect during that timeframe at [redacted] per Dth, customers would not only have benefitted from price stability, they would have saved money. This benefit is even larger if one expands the timeframe of the analysis to include the years 2000 to 2015. During that 15-year period, the [redacted] per Dth cost would have been lower than market prices 83% of the time.[70] In fact, for the majority of that period, gas prices were substantially above the [redacted] per Dth cost the Company believes is possible under the COSG Program.[71]

2. <u>The Likely Cost of the COSG Program Is Very Reasonable</u>.

Certainly, at the anticipated price identified by Mr. White, even if gas prices remain low for a time, the cost of the COSG Program for Nebraska customers relative to spot market purchases would be extremely small and the stability benefits substantial. But the same would be true even with a higher all-in COSG Program cost. As noted in Mr. Carr's rebuttal and Hearing testimony, and his Exhibit AC-3, if one assumes a higher all-in cost of production ($5.26 per Dth in year one), the monthly cost of the COSG Program to a typical Nebraska customer would only

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[68] Hearing Tr., Page 53, Line 23 to Page 54, Line 9; Page 181, Lines 14-22.
[69] Hearing Ex. 122, Highly Confidential White Rebuttal Testimony, Page 4, Lines 12-14.
[70] *Id.*, Lines 18-19.
[71] *Id.*, Page 4, Line 19 to Page 5, Line 2.

be $1.82.[72] That is in the most expensive illustrative year and does not account for the years when actual market prices are higher than the all-in production cost under the COSG Program and customers receive Hedge Credits. Put otherwise, in the worst years of the Company's illustrative model, Nebraska customers would receive the hedging benefits of the COSG Program for less than $2.00 per month, and in the best years, they would also save money. Under any analysis, such a minimal expense to create stable prices is clearly reasonable and prudent, particularly where there is a strong prospect that in other years the COSG Program will save customers money over the market.

While intervenors want to force the discussion in this proceeding to be about the alleged uncertainty of whether customers will save money or not, that argument is misplaced. The COSG Program is structured to provide customers with reasonably anticipated savings over the course of the program. However, customer savings are a bonus benefit, and not the primary benefit. As Ms. Ryan noted in her testimony, the purpose of hedging is not to try to outperform the market:

> "'[H]edging' refers to strategies to manage the cost of natural gas, providing rate stability and reducing the risk of rising natural gas costs for the utility's customers. When a utility can fix or cap the price in a forward contract, it is hedging. This is a deliberate action to manage costs and is not speculative. Instead, utilities' hedging is the act of reducing price risk exposure in a portfolio ***and is not related to profit and gain or trying to 'beat the market.'*** The act of locking into a price means the utility has accepted that price on behalf of its customers. It is willing to forego further opportunity in exchange for protecting against prices moving disadvantageously for customers."[73]

Furthermore, intervenors' claim that the COSG Program will expose customers to counterparty or bad debt risk is unsupported. As Mr. Kilpatrick noted during the Hearing, such risks would be

[72] Hearing Ex. 118, Carr Rebuttal Testimony, Page 6, Lines 7-13; *id.*, Exhibit AC-3; Hearing Ex. 106, Revised Carr Direct Testimony, Exhibit AC-2; Hearing Tr., Page 329, Lines 13-22.
[73] Hearing Ex. 110, Confidential Ryan Direct Testimony, Page 5, Lines 1-9 (emphasis added).

minimal or non-existent under the COSG Program because COSGCO would confirm the creditworthiness of any counterparties purchasing gas and, at most, any risk exposure would only exist for a 30-day payment period after the gas is sold.[74] Therefore, given the above evidence, the Commission can easily approve the Company's COSG Program as a reasonable and prudent way to minimize price instability for customers.

E. This Phase I Proceeding Will Not Result in Implementation of the COSG Program and Will Not Have Any Impact on Customer Rates.

Despite intervenors' attempts to muddy the water on this issue, approval of this Phase I proceeding will not result in the implementation of the COSG Program and will not result in any immediate impact on customer rates. Rates will only be impacted if the Commission approves the Company's Phase II application or approves cost recovery in another proceeding. Phase I gives the Commission a non-binding free look at a potential property in a Phase II proceeding based on the structure, scope, and guidelines approved in Phase I. The Company has made this point absolutely clear. The COSG Agreement states as much,[75] the Company's pre-filed testimony makes that point clear,[76] as do Black Hills Energy's responses to data requests,[77] and witness testimony at the Hearing drives this point home even further.[78] As Mr. Vancas reiterated in response to a question by the Commission at the Hearing, this Phase I proceeding does not commit the Commission to finalize implementation of the COSG Program.[79] Rather, approval simply provides the Company with information concerning the scope, structure, and guidelines it needs to appropriately size any acquisition for the COSG Program, so as to minimize the overall

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[74] Hearing Tr., Page 278, Lines 3-17.
[75] Hearing Ex. 101, Vancas Direct Testimony, Exhibit IV-1 (COSG Agreement), Section 4.3(ii).
[76] Hearing Ex. 102, Confidential Vancas Direct Testimony, Pages 5-6, 20-21, 24, 32-33; Hearing Ex. 116, Highly Confidential Vancas Rebuttal Testimony, Pages 12-13.
[77] *See, e.g.*, Hearing Ex. 260, Response to DR Request from Nebraska Public Advocate PA-57.
[78] Hearing Tr., Page 53, Lines 13-22; Page 331, Lines 6-23.
[79] *Id.*, Page 56, Lines 8-24.

cost of the program.[80] Specifically, without knowing the percentage at which utilities will participate, the acquisition and drilling criteria, and the other guidelines required by the COSG Program, Black Hills would not be able to find an appropriate reserve property or create a reasonable drilling plan for the Commission to consider.[81]

Intervenors have attempted to argue, wrongly, that even without a subsequent Commission approval, the Company could recover some costs incurred in Phase I or prior to Phase II. That is incorrect. In point of fact, because the COSG Agreement only allows costs to be passed through the GCA ***after*** a property acquisition is approved in Phase II, by extension, if there is no Phase II approval, any Phase I or pre-Phase II-related costs ***could not be recovered*** unless (i) the Company filed a separate action to collect those costs, ***and*** (ii) the Commission approved recovery of those costs in that proceeding.[82]

F. The COSG Program Addresses the Substantive Considerations Identified in the Consultant Report Prepared for the Commission.

The report prepared for the Commission by Christensen Associates Energy Consulting, LLC acknowledged the volatility of natural gas prices, noted that, due to that price variability, "there is good reason for distributors to hedge to natural gas prices, particularly beyond an annual timeframe,"[83] and found that the "COSG Program is conceptually attractive, and worthy of serious consideration by the Commission."[84] The COSG Program also addresses the report's three substantive considerations. First, the COSG Program accounts for risks and uncertainty in candidate properties by focusing solely on proven reserves in fields with low dry hole risk and

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[80] Hearing Ex. 102, Confidential Vancas Direct Testimony, Pages 5-6, 20-22, 24, 32-33; Hearing Ex. 116, Highly Confidential Vancas Rebuttal Testimony, Pages 3-4, 12-13, 25-26.
[81] Hearing Tr., Page 56, Line 8 to Page 57, Line 15; Hearing Ex. 116, Highly Confidential Vancas Rebuttal Testimony, Pages 3-4, 25-26.
[82] Hearing Ex. 101, Vancas Direct Testimony, Exhibit IV-1 (COSG Agreement), Section 4.3(ii); Hearing Ex. 260, Response to DR Request from Nebraska Public Advocate PA-57.
[83] Hearing Ex. 4, Report of Commission Consultant Christensen Associates Energy Consulting, Page 9.
[84] *Id.*, Page 7.

established costs and by requiring that acquired properties contain on a value basis primarily existing producing wells (*i.e.*, PDPs). Second, the COSG Program shares benefits and losses between customers and shareholders. In its rebuttal testimony, Black Hills also agreed to cap certain costs under the program. Third, the intensive analytics in the COSG Program model (Exhibit AC-2) will be used to assess benefits and risks associated with specific properties. Mr. McGarry agreed that it is a "very detailed and interrogated model" and a "useful economic tool" to assess specific properties.[85] As the COSG Program addresses these substantive considerations, the report supports approval of the Application before the Commission in this Phase I proceeding.

G. The Concerns Raised by Intervenors Either Have Been Addressed or Are Not a Proper Basis on Which to Deny the Company's Phase I Application.

In the face of all of the foregoing evidence (nearly all of which is uncontested), and supporting legal authority, intervenors have raised a series of issues in an attempt to dissuade the Commission from approving the Company's Application and allowing a Phase II proceeding to take place. As noted above, underlying the marketer-intervenors' concerns is the fear that the COSG Program could affect their own bottom line.

To the extent the Company has not addressed intervenors' issues and concerns above, Black Hills Energy addresses them in the material that follows.

1. <u>The COSG Program Is Not a BHEP Bailout, and Does Not Present Vertical Integration Concerns</u>.

Throughout the testimony, and in particular CNEG's testimony and its counsel's opening and closing statements, intervenors have alleged that the COSG Program was devised somehow as a means of bailing out BHEP. This claim is simply unsupported. Mr. Benton made clear that BHEP is not a distressed company, is not on the verge of bankruptcy, and does not need the

[85] Hearing Ex. 200, McGarry Direct Testimony, Page 32, Lines 1-3

COSG Program for its business.[86] In addition, he also made clear that, no matter whether BHEP acts only in a consulting role or in any other capacity, the uncontroverted evidence is that BHEP would not be making any profit, but would simply be recovering the costs it incurs.[87] Thus, if the COSG Program were a "bailout" (and it is not), it would be a very poor one indeed. It is a benefit, not a detriment, to utilize BHEP's expertise in the acquisition and development of gas reserves under the COSG Program because its motives will be aligned with Black Hills and its utility focus.[88]

Nor has Black Hills proposed that BHEP's Mancos reserves be used in the COSG Program. The Company has reiterated numerous times in this proceeding, and others, that no decision has been made about what reserves would be proposed to the Commission if Phase I approval were granted. Fundamentally, whatever property is proposed, and whatever role BHEP might serve with respect to that property, would have to be presented to the Commission in the Phase II proceeding, would have to be justified and shown to be prudent, and would have to be approved by the Commission.

During the Hearing, CNEG's counsel raised the hypothetical scenario of BHEP somehow retaining liquids associated with reserves COSGCO acquired.[89] This hypothetical was premised on CNEG's counsel's express assumption that "there's nothing in the COSG agreement that says BHEP cannot monetize the other assets at the well head."[90] Of course, that hypothetical ignores the COSG Agreement and the Company's testimony, in both of which it is made clear that ***all*** liquids associated with the reserves acquired will be retained in the COSG Program, and then

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[86] Hearing Ex. 107, Benton Direct Testimony, Page 20, Line 8 to Page 23, Line 6; Hearing Tr., Page 228, Line 20 to Page 229, Line 2.
[87] Hearing Tr., Page 229, Line 3 to Page 233, Line 22.
[88] *Id*.
[89] *Id.*, Page 220, Line 10 to Page 221, Line 4.
[90] *Id.*, Page 220, Line 23 to Page 221, Line 3.

developed and sold for the customers' benefit.[91] This is yet another example of CNEG using scare tactics, which is not altogether surprising given that the facts do not support CNEG.

CNEG also mused in its closing argument that BHEP could sell gas from its Piceance Mancos shale assets to the Company at an attractive price for customers over the long-term since "they don't have to go drill for it."[92] However, the record shows that BHEP would, in fact, need to drill many more wells, as BHEP's existing production from the Piceance Basin, which includes but is not limited to existing production from the Mancos shale, would be insufficient for the COSG Program as proposed.[93] And, as Mr. Benton testified, because production from wells naturally declines over time, particularly early in their producing life, "producers must continue to drill new wells each year to maintain the same amount of production in a field."[94] Clearly, BHEP's existing Mancos production (even after accounting for the four wells that have been drilled but not completed) is not sufficient and additional drilling would be needed. CNEG's suggestion, like its other arguments, is simply without basis and distorts the evidence before the Commission.[95]

Intervenors also argue that the COSG Program presents "vertical integration concerns," although they do not identify any actual (as opposed to purely hypothetical) issues with it. As noted, and as confirmed by the Company repeatedly, Black Hills Energy would not be profiting

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[91] Hearing Ex. 101, Vancas Direct Testimony, Exhibit IV-1 (COSG Agreement), Sections 1, 4.1, 4.2(xiv); Hearing Ex. 106, Revised Carr Direct Testimony, Page 12, Lines 16-21, Page 22, Lines 17-20 ("The Company proposes that COSGCO will sell to the market 100% of all associated oil and NGLs (after the cost of processing, transportation, marketing, etc.) as a credit to the production cost of natural gas under the COSG Program.").

[92] Hearing Tr., Page 432, Lines 22-23.

[93] *See*, Hearing Ex. 272, Response to DR Request from Nebraska Public Advocate PA-73, HIGHLY SENSITIVE CONFIDENTIAL Attachment (AC-2 with Mancos), "Financial Model" worksheet, Row 5, Column I (projecting just 12.4 dekatherms of production in the first full year of the COSG Program assuming additional wells are drilled and completed).

[94] Hearing Tr., Page 200, Line 17 to Page 201, Line 14; Hearing Ex. 107, Benton Direct Testimony, Page 11, Lines 8-10.

[95] CNEG may claim that Mr. Benton testified at the Hearing that BHEP could provide a long-term hedge. Mr. Benton actually testified that BHEP would like to sell more gas (Hearing Tr., Page 211, Lines 8-22), which is not the same as being able to provide a long-term hedge. As noted above, BHEP's existing wells would not be sufficient for a long-term hedging program; further drilling would be necessary.

from the COSG Program.[96] The opportunity to realize an ROE on the capital invested in the COSG Program is consistent with capital expenditures made in the utility context. For instance, if the Company itself approached the Commission to purchase the reserves directly and the purchase were approved by the Commission, the Company would have the opportunity to realize an ROE on that invested capital.[97] The primary reasons that a direct utility-ownership structure is not being proposed for the COSG Program are that (i) tax benefits can be maximized under the proposed structure and those tax benefits would flow through to customers and (ii) the proposed structure allows the COSG Program to function efficiently on a multi-jurisdiction basis.[98] There is no unwarranted benefit that would be provided to the Company or its affiliates under the COSG Program. Indeed, a nearly identical structure has thrived for decades in Utah and Wyoming under the Wexpro program, generating over $1 billion in historical savings for customers.[99]

2. <u>The COSG Program Is Fully Transparent; There Are No Restrictions That Prevent the Commission from Having Full Visibility into the COSG Program</u>.

In a plainly unsupported attack on the COSG Program, intervenors, and in particular CNEG, have alleged that, in some way, the COSG Program does not afford the Commission full visibility into the inner workings of the program's operations. For example, during the Hearing, CNEG attempted to argue that the COSG Agreement does not expressly provide the Commission with full access to all of the information regarding operations related to the COSG Program.[100] This argument has no merit. In fact, lack of visibility is precisely what the Commission currently

[96] Hearing Tr., Page 229, Line 3 to Page 233, Line 22; Hearing Ex. 106, Revised Carr Direct Testimony, Page 13, Lines 1-10, Page 16, Line 12 to Page 17, Line 3; Hearing Ex. 116, Highly Confidential Vancas Rebuttal Testimony, Page 14, Line 8 to Page 15, Line 7, Page 36, Line 13 to Page 38, Line 9.
[97] Hearing Ex. 116, Highly Confidential Vancas Rebuttal Testimony, Page 17, Lines 1-13.
[98] Hearing Ex. 106, Revised Carr Direct Testimony, Page 17, Line 4 to Page 19, Line 2.
[99] Hearing Ex. 102, Confidential Vancas Direct Testimony, Page 12, Line 3 to Page 13, Line 16.
[100] Hearing Tr., Page 106, Line 22 to Page 107, Line 18, Page 246, Line 18 to Page 247, Line 23, Page 299, Line 25 to Page 300, Line 24, Page 434, Line 24 to Page 435, Line 16, Page 437, Line 5 to Page 438, Line 1.

has with respect to gas supply, in that it cannot see any of the elements of the pricing of natural gas by CNEG and other marketers. The converse is true relative to the COSG Program.

First, Sections 2.2 and 2.3 of the COSG Agreement expressly provide the Commission with unfettered access to all of BHUH's and COSGCO's "books, accounts, and records regarding the Properties and this COSG Agreement" and to any information in the possession of the Monitors. As BHUH would be the parent company of COSGCO, and COSGCO would have all of the documents (or access to such documents under the audit provision of a joint operating agreement) of any dealings with any suppliers, contractors, or other service providers under the COSG Program, those sections give the Commission complete access to all information or documents regarding the COSG Program. And that would be on top of the Commission's already broad access to the Company's records. The Company has also made clear that this access to information would include access to BHEP's information regarding the COSG Program, if any.[101] Finally, as the Company's witnesses confirmed during the Hearing, there is no provision in the COSG Agreement that would limit access to any information concerning the COSG Program, and intervenors have identified none.[102]

Intervenors' claimed lack of transparency or access to information is nonsensical. The COSG Program involves this Phase I proceeding, Phase II reviews by the Commission of proposed acquisitions and drilling plans, and annual reports from the Monitors. Moreover, as Mr. Kilpatrick confirmed during the Hearing, costs passed through the GCA would be addressed in the same way they always have been, with the Commission having the statutory right to audit

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[101] Hearing Ex. 116, Highly Confidential Vancas Rebuttal Testimony, Page 37, Lines 11-16, Page 38, Lines 1-9; Responses to DR Requests from Nebraska CNEG 1-10, 1-11.
[102] Hearing Tr., Page 106, Line 22 to Page 107, Line 18, Page 299, Line 25 to Page 300, Line 24.

and review all costs and the information underlying those costs.[103] Each of these stages requires the Company to make disclosures of information to the Commission and, if the Commission does not believe it has adequate disclosure, it can withhold approval, replace the Monitors, order proceedings to audit costs, and take other authorized actions. The COSG Program is fully transparent.

3. The Hydrocarbon and Accounting Monitors Provide Significant and Independent Oversight to Safeguard the COSG Program's Proper Operation.

In a related critique of the COSG Program, intervenors claim the Monitors would not be truly independent, would lack sufficient time or information to properly perform the functions expected of them, and would not provide adequate oversight. Their arguments are unsupported and contrary to the undisputed facts.

First, while Mr. McGarry acknowledges that the Commission has regularly used independent advisors to provide expert assistance in Commission activities, he attempts to argue the Monitors would not be truly independent because BHUH retains them and writes the checks to pay them.[104] This argument can be dismissed easily. Section 2.1 of the COSG Agreement requires the Monitors to be "mutually agreeable to BHUH and the PUCs."[105] Hence, they cannot be retained without Commission agreement, and if at any point they ceased to be "agreeable" to the Commission, the Commission could have them replaced, which the Company confirmed in its testimony at the Hearing.[106] In addition, Section 2.2 of the COSG Agreement guarantees the Commission the right to participate in any discussion with the Monitors and prevents any *ex parte*

[103] *Id.*, Page 298, Line 20 to Page 300, Line 24.
[104] Hearing Ex. 200, McGarry Direct Testimony, Page 7, Line 20 to Page 21, Line 3, Page 29, Line 19 to Page 30, Line 7.
[105] *See also* Hearing Ex. 102, Confidential Vancas Direct Testimony, Page 5, Lines 11-16; Hearing Ex. 106, Revised Carr Direct Testimony, Page 7, Lines 14-16; Hearing Tr., Page 81, Lines 1-21.
[106] Hearing Tr., Page 165, Line 12 to Page 166, Line 23.

communications by the Company with the Monitors. Finally, the Company noted in the Hearing that it has no objection to having the Commission write the check for the Monitors.[107] Given these facts, there is no basis for concern about the independence of the Monitors.

Second, intervenors' claim that the Monitors would have insufficient time to perform their duties refers to the 10-day timeframe for the Hydrocarbon Monitor to issue its report under Section 4.3 of the COSG Agreement.[108] This argument, however, misrepresents both the language of Section 4.3 and the practical realities of how that provision would function.

Section 4.3 does not require the Hydrocarbon Monitor to issue its written report within 10 days of its becoming aware of a potential acquisition or of receiving information regarding the proposed acquisition. Rather, the report is to issue 10 days "following receipt ***of all the information*** described in Section 4.2 . . . ."[109] As Mr. Carr and Mr. Vancas explained at the Hearing, because of the expansive nature of the information that would have to be provided to the Hydrocarbon Monitor under Section 4.2, the Hydrocarbon Monitor will have much more time than 10 days to do an analysis of the information and to provide the report referenced in Section 4.3.[110] Furthermore, the Hydrocarbon Monitor will be an expert in the field, and no intervenor submitted any actual evidence indicating that the timeframe in the COSG Agreement is insufficient.

Finally, the claim that the Monitors would not provide adequate oversight is not based on any evidence. Instead, it is premised upon intervenors' own incorrect interpretation of the COSG Agreement. With regard to the Hydrocarbon Monitor, CNEG attempted to show that, because the language of Section 4.2 does not expressly state that the Hydrocarbon Monitor could consider

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[107] *Id*., Page 415, Lines 12-15.

[108] There has been no claim by intervenors that the Accounting Monitor would not have sufficient time to perform the duties expected of it.

[109] Hearing Ex. 101, Vancas Direct Testimony, Exhibit IV-1 (COSG Agreement), Section 4.3 (emphasis added); *see also* Hearing Tr., Page 83, Lines 12-22, Page 350, Lines 1-14.

[110] Hearing Tr., Page 83, Lines 2-23, Page 158, Line 9 to Page 159, Line 8, Page 350, Lines 1-14.

information beyond what is referenced in that section, it is precluded from doing so and must simply accept as correct the information provided by BHUH.[111] This argument failed. Mr. Carr clarified that the COSG Agreement ***does not contain*** any provision preventing the Hydrocarbon Monitor from reviewing any information it believed was necessary, nor does it contain any provision requiring the Hydrocarbon Monitor to accept the information provided by BHUH.[112] Furthermore, intervenors did not provide any evidence challenging the adequacy of the information that would be provided to the Hydrocarbon Monitor pursuant to Section 4.2. Indeed, Mr. McGarry in both his pre-filed and Hearing testimony stated that he does not take issue with the adequacy of the information the Hydrocarbon Monitor would assess.[113] As a final point, if the Hydrocarbon Monitor were not satisfied with the information provided or did not have sufficient time to review the information, it could simply reject the proposed acquisition and the property could not be proposed to the Commission.[114]

The situation is no different for the Accounting Monitor. The COSG Agreement states that it will provide an assurance report, assessing the accuracy of the calculations under the COSG Program.[115] There is no provision in the COSG Agreement that restricts what financial information the Accounting Monitor could review in the course of this duty, and as Mr. Kilpatrick explained, the assurance report can be shaped to address Commission interests and concerns.[116] Mr. Vancas testified that the Accounting Monitor and the Commission will be able to review "the costs that BHEP charges COSGCO, and you'll be able to determine that they are indeed at cost

[111] *Id*., Page 347, Line 9 to Page 350, Line 14.
[112] *Id*.
[113] Hearing Ex. 200, McGarry Direct Testimony, Page 25, Lines 19-20; Hearing Tr., Page 404, Lines 11-25.
[114] *See* Hearing Ex. 101, Vancas Direct Testimony, Exhibit IV-1 (COSG Agreement), Section 4.3.
[115] *Id.*, Section 2.1.
[116] Hearing Tr., Page 283, Lines 6-24.

and not with a profit."[117] Finally, as Mr. Kilpatrick further explained, the Commission retains its full authority to audit the COSG Program and disallow any imprudent costs.[118]

4. <u>The COSG Program Does Not Transfer Gas Supply Cost Risks to Customers; It Transfers Risk to Shareholders Who Would Take on Risks They Currently Do Not Have and Costs They Currently Do Not Pay</u>.

As noted above, Nebraska customers currently bear 100% of the gas supply cost risk associated with prudent gas purchases and hedges, including the built-in unregulated returns producers and marketers charge, which are passed through to customers in the GCA.[119] Black Hills' shareholders currently do not bear any of those gas supply cost risks; customers bear the risk of volatile and increasing gas supply costs. Under the COSG Program, though, shareholders would bear some of the gas supply cost risks currently borne by Nebraska customers. [120]

The COSG Program incorporates a 100-basis-point deadband around the Allowed ROE.[121] Under this approach, costs would continue to be passed through the GCA as they always have, but where the Actual ROE of the COSG Program is up to 100 basis points below the Allowed ROE, Black Hills' shareholders, not customers, would cover the shortfall.[122] Black Hills has also indicated that it would not be opposed to the Commission ordering the deadband to be expanded to +/- 200 basis points around the Allowed ROE.[123] During the Hearing, Mr. Kilpatrick explained the risk that would be borne by shareholders in this way:

"Q. Okay. Under the program, would the shareholders take on any risk if there was a market change and prices either dropped to a point where -- let's just say, use Mr. Austin's example: If market prices were below

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[117] *Id.*, Page 107, Lines 16-18.
[118] *Id.*, Page 295, Line 8 to Page 296, Line 17; Page 300, Lines 19-24.
[119] Hearing Ex. 116, Highly Confidential Vancas Rebuttal Testimony, Page 15, Lines 12-17, Page 17, Line 17 to Page 20, Line 10.
[120] *Id.*, Page 17, Line 17 to Page 19, Line 1, Page 18, Lines 10-11, Page 19, Lines 15-17.
[121] *Id.*, Page 18, Lines 13-14, Page 19, Lines 4-6; Hearing Ex. 101, Vancas Direct Testimony, Exhibit IV-1 (COSG Agreement), Section 5.1; Hearing Ex. 106, Revised Carr Direct Testimony, Page 16, Line 14 to Page 17, Line 3.
[122] *Id.*
[123] Hearing Ex. 116, Highly Confidential Vancas Rebuttal Testimony, Page 6, Line 20 to Page 7, Line 3.

what you had anticipated and there's a potential for a hedge cost, would shareholders be taking on risk?

A. Yes, they are.

Q. And what kind of risk are they taking on?

A. At a minimum, the hundred basis points as outlined in our original application, and the 200 basis points we outlined in our rebuttal testimony.

Q. And that's not a risk that shareholders would pay today?

A. That is correct."[124]

Black Hills is not seeking to foist onto customers through the COSG Program an existing drilling operation for which its shareholders bear responsibility. Rather, the COSG Program proposes that COSGCO produce gas from developing acquired proven reserves solely and exclusively for Black Hills' utilities that participate in the program. COSGCO would not have any function other than operating the COSG Program ***for the participating Black Hills utilities***. It would not have any other purpose or goal.[125] Because Black Hills shareholders bear no risk for prudently incurred gas supply costs today, the implementation of the COSG Program cannot ***transfer*** any such risk from Black Hills or its shareholders to customers.

Over the long-term, market gas prices will contain all of the costs incurred by producers and marketers, including drilling costs, operating costs, insurance costs, royalties paid to reserve owners, return on equity, etc.[126] Those same costs would be incorporated into the cost of gas under the COSG Program. The major difference, however, is that, under the COSG Program, the utility (through COSGCO) would have a measure of control over those costs, which does not exist today, and the ROE would be a utility-like rate, which is not the case with supplies purchased in

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124 Hearing Tr., Page 299, Lines 6-20.
125 Hearing Ex. 101, Vancas Direct Testimony, Exhibit IV-1 (COSG Agreement), Section 4.1(ii).
126 Hearing Ex. 116, Highly Confidential Vancas Rebuttal Testimony, Page 16, Lines 8-11.

the market.[127] The cost of gas supply charged by the marketers (including CNEG) contains an unregulated profit margin and is not simply the cost and a utility-like regulated return.

The COSG Program, by its design, protects customers from undue risk in multiple ways.[128] To highlight just a few examples of the ways in which the COSG Program mitigates risk, it focuses on ***proven reserves*** that have "(i) an established history of Gas production, (ii) low dry hole risk, and (iii) an established history of reserves per well and costs per well."[129] The acquired reserves must be primarily proved developed producing reserves (PDPs) on a value basis,[130] must be located in the Rockies or Mid-Continent,[131] and produce primarily methane.[132] All revenues from liquids associated with the acquired reserve interest will benefit customers.[133] The program can accommodate decreasing utility demand.[134] The independent Hydrocarbon Monitor must conclude that the Acquisition Criteria are satisfied before a proposed acquisition is brought to the Commission for consideration.[135] Both the magnitude and probability of risk have been minimized by the COSG Program structure.

5. Nebraska Customers Would Not Bear More Than Their Share of the COSG Program Costs.

A concern raised in this proceeding is whether Nebraska customers could be responsible for program costs of utilities that do not participate in the COSG Program. There are two components to this issue: (i) whether Nebraska customers would have to bear any costs incurred by other utilities; and (ii) whether Nebraska customers could bear an inappropriately larger

[127] *Id.*, Page 14, Line 18 to Page 15, Line 7, Page 16, Lines 8-11, Page 18, Lines 7-17.
[128] *See generally* Hearing Ex. 106, Revised Carr Direct Testimony.
[129] Hearing Ex. 101, Vancas Direct Testimony, Exhibit IV-1 (COSG Agreement), Exhibit A.
[130] *Id.*
[131] *Id.*
[132] *Id.*
[133] Hearing Ex. 106, Revised Carr Direct Testimony, Page 12, Lines 14-21.
[134] Hearing Ex. 101, Vancas Direct Testimony, Exhibit IV-1 (COSG Agreement), Section 3.4.
[135] *Id.*, Section 4.3

percentage share of certain fixed administrative or other costs if some utilities do not participate in the COSG Program.

With regard to the first question, under the COSG Program, Nebraska customers would not bear, under any circumstance, costs incurred by or for the benefit of another utility. For example, if the Colorado commission did not ultimately permit Black Hills/Colorado Gas Utility Company, LLC ("Black Hills Colorado") to participate in the COSG Program, any costs incurred for Colorado-specific actions would be the responsibility of Black Hills Colorado, not the Company or Nebraska customers. Similarly, if Black Hills Colorado did not participate in the COSG Program, the percentage share of the program Black Hills Colorado customers would have otherwise taken ***would not be reallocated to the Company or Nebraska customers***.[136] Instead, the reserves would be sized to correspond to the demand of those utilities that obtain Phase I and Phase II approvals.

Mr. Vancas made these points clear during the Hearing: "Any costs that we incurred pulling together the testimony for Colorado, filing in Colorado, answering their data requests, et cetera. Those are all costs that Black Hills will bear and will not be recoverable in the program, should it not proceed in Colorado."[137] He also explained:

> "[A]gain, the reason for the Phase 1 proceeding is to know how much gas each state wants to hedge so we know what size of property to buy. You don't want to buy a five-bedroom house and have two bedrooms vacant. Likewise, you don't want to buy a three-bedroom house and you need five bedrooms, so we need to size that property. And when you size that property, you're only buying for the participating states. . . . We're not going to pass [other state's] costs on to Nebraska or any other state participating. . . ."[138]

Commissioner Schram also questioned Mr. Carr about this issue, leading to the following

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[136] Hearing Tr., Page 154, Lines 9-14.
[137] *Id*., Page 56, Lines 18-24.
[138] *Id*., Page 153, Line 20 to Page 154, Line 3; Page 154, Lines 12-14.

exchange:

> "COMMISSIONER SCHRAM: Okay. Then on the table, it's [page] 5 of 13 of AC-2. We had a discussion yesterday of the multi-states and discussion of Colorado. How does that impact this chart as presented if the Colorado order is not to participate?
>
> MR. CARR: Sure.
>
> COMMISSIONER SCHRAM: What impact would it show?
>
> MR. CARR: I appreciate that. The property would -- the search for a property would be sized to meet the volumetric requirements desired by those participating jurisdictions. So in this instance when we show the total volumes and percentage breakouts, if Colorado were not to be a participant in the future, we would remove those volumes and size and search for a property that would be a better fit for the remaining jurisdictions.
>
> COMMISSIONER SCHRAM: It would change these numbers accordingly?
>
> MR. CARR: Yes . . . ."[139]

The second question – regarding how fixed administrative and other fixed costs would be allocated if some utilities do not participate – is more nuanced. There clearly are certain costs that would be incurred to operate the COSG Program whether it was for one utility or multiple utilities. For instance, if a Monitor charged $10,000 for work and that charge would have been the same no matter the number of utilities participating, the participating utilities would allocate that cost between them based on each utility's respective share of the collective COSG Program or a specific property, as the case may be. When Mr. Vancas was asked about this allocation issue, he explained it this way:

> "Q. If Colorado doesn't participate, have you -- has your company made any calculations as to whether additional administrative costs will be shifted to the other jurisdictions?
>
> A. We don't believe that there will be additional administrative costs

[139] *Id.*, Page 360, Line 19 to Page 361, Line 21.

> incurred, ***there would be some level of administration required for a program of any size***.
>
> Q. Okay. To the extent that would otherwise have been shared with Colorado, that option is out for the time being; is that correct?
>
> A. ***I think it's fair to say that the more states that participate, the more of the costs they absorb for administrating the program, so they help you***.
>
> Q. Okay.
>
> A. Which is part of the reason we file it as a multi-state program.
>
> Q. Okay."[140]

In addition, as Mr. Carr noted in response to Ms. Mulcahy's questions on this point, some fixed administrative or other costs could be reduced if fewer utilities participate in the COSG Program:

> "So clearly, if we have everyone participate, we can look for a larger size property, if it's just one-or-two jurisdiction[s]. Certainly, we have to look for different size properties. And quite honestly, a lot of the operating expenses are going to be variable, right? I would expect that we could even offer that some of the fixed costs to manage the program would be less 'cause you have fewer wells to drill, et cetera."[141]

Consequently, if some utilities approved the COSG Program, but others did not, the participating utilities would share those fixed costs that may not be capable of being reduced proportionally to the number of utilities participating.

Even though, as Mr. Carr acknowledged, the Company cannot in this Phase I proceeding enumerate the allocation of fixed costs in dollars and cents,[142] it is clear that Nebraska customers will never be responsible for an inappropriately larger percentage share of any fixed costs as a result of another utility's non-participation. If, for example, Nebraska was the only participating state, all of the $10,000 example in the preceding paragraph would be allocated to Nebraska

[140] *Id*., Page 108, Line 15 to Page 109, Line 7 (emphases added).
[141] *Id*., Page 366, Lines 12-22.
[142] Hearing Tr., Page 364, Line 23 to Page 365, Lines 12.

customers. This would be entirely appropriate and justified. If other states participate, less than $10,000 would be allocated to Nebraska customers. Nebraska customers would never be responsible for more than $10,000. Clearly, it is a benefit if other utilities participate, but non-participation does not result in Nebraska customers bearing more than their appropriate share of COSG Program costs.[143]

6. <u>The COSG Program Does Not Guarantee Cost Recovery or an ROE, the Mechanism for Establishing the ROE Is Lawful, Prudent and Reasonable</u>.

Intervenors argue that the COSG Program is problematic because it "guarantees" both cost recovery and an ROE to an unregulated affiliate of the Company. They also argue that the mechanism for establishing the ROE in the COSG Program deprives the Commission of the ability to set the ROE under the COSG Program and is not justified. Both arguments are incorrect and not supported by the record.[144]

Cost recovery and the earning of the Allowed ROE is not guaranteed. Just as the Commission authorizes an ROE for the Company in its general rate cases (that may or may not actually be earned), under the COSG Program, the Commission would authorize an Allowed ROE (which, in the same way, may or may not be earned).[145] Similarly, just as the Commission allows recovery of prudently incurred costs, the same is proposed for the COSG Program. Mr. Vancas explained it this way in cross-examination by the Public Advocate at the Hearing:

> "Q. [M]y understanding of this agreement is that you will get a guaranteed return of equity, correct?

[143] During closing arguments, CNEG's counsel claimed that Mr. Vancas' and Mr. Carr's responses concerning the allocation of costs in the event some utilities do not participate were inconsistent. That is incorrect. CNEG's counsel failed to note the distinctions made by Mr. Vancas in the testimony cited above relating to differences between how acquisition and variable costs are addressed in the COSG Program, and fixed administrative costs, to the extent they could not be reduced based on the size of the COSG Program.

[144] The Company enters into all sorts of contracts with unregulated entities, including for gas supply, in the normal course of business.

[145] Hearing Ex. 124, McKenzie Rebuttal Testimony, Page 3, Lines 11-19, Page 5, Lines 7-19, Page 15, Line 13 to Page 16, Line 7.

A. No. And, you know, you've said that in your [opening statement]. I mean, look at the way Nebraska gas works today. We put pipe in the ground and the Commission says if that pipe was prudent, we get to earn a return on the equity portion of the capital it took to pay for that pipe. Plus we get to recover prudently incurred operating expenses. That's today's formula. That's the formula that we're applying to cost-of-service gas.

. . . .

Q. (BY MR. AUSTIN) Would you agree with me that the authorized rate of return approved in a general rate case does not guarantee that rate of return to the utility?

A. That it will be earned?

Q. No.

A. Correct.

Q. Did it -- that it is not guaranteed.

A. Mr. Austin, you're going to have to define what "guaranteed" means. I -- the Commission authoriz[es] me to take that -- authorized ROE and multiply it by my rate base. That's what I'm doing in cost-of-service gas. I don't see how this is any different."[146]

In other words, if the Actual ROE under the COSG Program is less than the Allowed ROE, BHUH will not recover the Allowed ROE, in the same way the Company, as noted by Mr. McKenzie, is not guaranteed to earn its authorized ROE for its utility operations.[147] In addition, if there are costs that the Commission has not authorized that are later determined to be imprudent, those costs would not be recoverable. The COSG Program affords an opportunity to earn the Allowed ROE but there is no guarantee that the Allowed ROE will be earned. These points were repeatedly made in the Company's pre-filed direct and rebuttal testimony and, as shown above, during the

[146] Hearing Tr., Page 75, Lines 4-14, Page 76, Line 19 to Page 77, Line 7.
[147] Hearing Ex. 124, McKenzie Rebuttal Testimony, Page 3, Lines 11-19, Page 5, Lines 7-19, Page 15, Line 13 to Page 16, Line 7.

Hearing.[148] Significantly, intervenors did not submit any evidence establishing the contrary.

Furthermore, the manner in which the Allowed ROE would be established under the COSG Program is within the Commission's authority, and the methodology for setting it is justified. The multi-state COSG Program would, ***if approved by the Commission***, use the average ROE of all utility rate cases as reported by the RRA to set the ROE under the COSG Program.[149] As Mr. Kilpatrick noted, this approach could only be pursued if approved by the Commission and, like other formula mechanisms in the utility industry, is not unusual.[150] Also, Mr. McKenzie explained this issue in his pre-filed rebuttal testimony:

> "Mr. McGarry suggests that reliance on an "external source" would undermine the PSC's regulatory jurisdiction. As discussed in my direct testimony, the customers already pay a return on equity capital to gas producers/suppliers through existing gas supply costs. This return is determined based on competitive market forces and the PSC has no ability to influence or constrain the returns earned by unregulated natural gas suppliers. Meanwhile, the COSG Program offers the opportunity to insulate customers from price risk while limiting the ROE to a reasonable level, predicated on an objective benchmark for regulated utilities. In contrast to Mr. McGarry's portrayal, the COSG Program expands rather than limits the PSC's ability to influence the returns on capital associated with the Company's gas supplies."[151]

Any suggestion by intervenors that a third-party benchmark cannot be used to establish a return willfully ignores that the Commission would be approving the use of the RRA benchmark in this very proceeding. Approving the use of this mechanism is fully within the Commission's lawful authority and implementation of this mechanism does not deprive the Commission of its authority.

In addition, intervenors contend that the RRA benchmark establishes an inappropriate Allowed ROE for the COSG Program because it is not the same as the Company's current

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[148] *Id.*; Hearing Ex. 116, Highly Confidential Vancas Rebuttal Testimony, Page 14, Line 8 to Page 15, Line 7; Hearing Tr., Page 75, Lines 4-14, Page 76, Line 19 to Page 77, Line 7, Page 273, Lines 17-20.
[149] Hearing Ex. 113, McKenzie Direct Testimony, Page 8, Line 14 to Page 9, Line 2, Page 15, Line 17 to Page 16, Line 26.
[150] Hearing Tr., Page 274, Line 24 to Page 275, Line 4.
[151] Hearing Ex. 124, McKenzie Rebuttal Testimony, Page 5, Lines 9-19.

authorized ROE and is not static.[152] However, intervenors never conducted a market study to assess whether the RRA benchmark is reasonable and justified for the COSG Program. In contrast, Mr. McKenzie performed a thorough market study and concluded that it is reasonable and justified. In this regard, he noted that the benchmark is both "predicated on authorized returns reported by a well-recognized, independent research organization, which provides the most comprehensive and objective source of authorized returns available in the industry," and is "an objective reference point that is straightforward, based on readily available historical data, insulated from abrupt or extreme changes, and offers administrative advantages by avoiding unneeded controversy, which can be protracted and costly to all stakeholders."[153] Indeed, Mr. McKenzie noted that, because it is based on "historical allowed returns," the RRA benchmark is likely to "understate investors' current required return and lag behind the cost of equity."[154] The record demonstrates that the RRA benchmark establishes a reasonable and justified Allowed ROE for the COSG Program.

7. <u>The Proposed 40/60 Debt/Equity Ratio Is Reasonable and Justified</u>.

Intervenors claim that the proposed 40/60 debt/equity ratio will result in overstated returns to Black Hills.[155] Apart from intervenors' incorrect ROE argument, noted above, intervenors' evidence on this point essentially consists of the fact that the Company's current authorized capital structure is 48/52 debt/equity.[156] Mr. McKenzie's pre-filed testimony fully supports the proposed capital structure for the COSG Program, but if the Commission had any doubts, the Company has indicated that it would accept a 50/50 debt/equity structure.

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[152] Hearing Ex. 200, McGarry Direct Testimony, Page 20, Lines 14-17; Hearing Ex. 301, Bennett Direct Testimony, Page 7, Lines 5-18.
[153] Hearing Ex. 113, McKenzie Direct Testimony, Page 2, Lines 24-27, Page 3, Lines 4-8.
[154] *Id.*, Page 3, Lines 11-12.
[155] Hearing Ex. 200, McGarry Direct Testimony, Page 7, Lines 12-13.
[156] *Id.*, Page 21, Line 18 to Page 22, Line 4.

8. The 60-Day Timeframe for Acquisition and Drilling Plan Review Is Appropriate.

Intervenors have criticized the COSG Program for the proposed 60-day review timeframe for proposed acquisitions and drilling plans. While the Company agrees that ensuring that the review timeframe is adequate is a legitimate concern, the proposed 60-day timeframe properly balances the market opportunities, costs, and time needed for review, particularly given the pre-qualification requirement that the Hydrocarbon Monitor conclude that the Acquisition Criteria are satisfied.[157]

As the Company explained, the 60-day time frame is not an arbitrary deadline. It stems from industry practice that most reserve deals close within 60 days, or sellers either pull out or require some termination fee if a longer period is used.[158] Thus, the 60-day period has been included to avoid losing out on potential acquisition opportunities while avoiding unnecessary fees that would make the acquisition more expensive.[159] Furthermore, a similar 60-day review period has been approved and used for cost of service gas programs in other jurisdictions.[160]

In addition, as noted, the 60-day timeframe would be adequate, particularly where, before any proposed acquisition could be presented to the Commission, it would first have to be approved by the Hydrocarbon Monitor as satisfying the Acquisition Criteria.[161] If the Commission determined that it needed additional time, it could either (i) have the Company request additional time (if that was possible), which the Company has offered to attempt to do,[162] or (ii) simply deny

[157] It is worth noting as an aside that it is not anticipated that the COSG Program would involve numerous acquisitions. Rather, the concept would be to find one or more reserve properties now at a favorable price that would satisfy the needs of the COSG Program, without the need to constantly be searching for more properties in a market that may be less favorable.

[158] Hearing Ex. 116, Highly Confidential Vancas Rebuttal Testimony, Page 9, Lines 13-22, Page 24, Lines 1-3; Hearing Tr. Page 91, Line 11 to Page 92, Line 8, Page 138, Lines 3-16.

[159] *Id*.

[160] Hearing Ex. 116, Highly Confidential Vancas Rebuttal Testimony, Page 24, Lines 3-5.

[161] Hearing Ex. 101, Vancas Direct Testimony, Exhibit IV-1 (COSG Agreement), Section 4.3.

[162] Hearing Ex. 116, Highly Confidential Vancas Rebuttal Testimony, Page 9, Line 9 to Page 10, Line 1, Page 24,

the Phase II application.[163] Finally, the Company has indicated that it would not be opposed to the Commission extending these timeframes as described in Mr. Vancas' rebuttal testimony, or to providing a fund with which the Public Advocate could have another expert, if necessary, on retainer to expeditiously review proposed acquisitions.[164]

9. The Termination Provision of the COSG Agreement Is Reasonable.

An oft-repeated but misguided refrain from intervenors in this proceeding has been their claim that Section 6.2 of the COSG Agreement (the termination provision) is not reasonable because it does not allow participating utilities to get out of the COSG Program without having to pay for their then-existing obligations.[165] In addition, they have incorrectly claimed that, even if the Commission ordered the Company to terminate its participation under Section 6.2, the Company's ability to terminate could be prevented by other utilities participating in the program. Both claims are incorrect.

Intervenors' contention that the termination provision is unreasonable because it requires participating utilities to fulfill existing obligations as part of the termination ignores industry realities and fails to properly assess the provision in context. For example, if Black Hills prudently entered into a contract to have a third party construct a generation facility, there would be no question that the utility should have to pay (and would have the right to recover from customers) any amounts required to fulfill its obligations under the contract, even if the builder allowed the Company to terminate midstream.

Lines 1-15.

[163] Hearing Tr., Page 331, Lines 6-22.

[164] Hearing Ex. 116, Highly Confidential Vancas Rebuttal Testimony, Page 9, Line 15 to Page 10, Line 5.

[165] Hearing Tr., Page 93, Line 19 to Page 96, Line 24, Page 162, Line 8 to Page 165, Line 11, Page 374, Lines 14-20, Page 423, Lines 6-25.

Despite the foregoing reality, intervenors seem to think that, even if Black Hills' shareholders invested millions of dollars to purchase a reserve interest for customers' benefit under the COSG Program, the termination provision should allow the Company to terminate its participation without having to pay its share of the outstanding investment cost (net of the proceeds from the sale of the interest), even though the investment would have been approved by the Commission in a Phase II proceeding. In point of fact, most contracts, and in particular hedging contracts, do not allow early termination and certainly not at zero cost to the terminating entity. Section 6.2 not only allows termination, but it provides for the sale of the Company's associated interest to offset and reduce any amounts then owing.

Furthermore, if Phase II approval were given, the Company would not be required to make continual expenditures for 20 to 30 years under the COSG Program with no way out, as intervenors claim.[166] After an initial acquisition, the COSG Agreement provides for a new drilling plan to be prepared and presented to the Commission every five years.[167] If the Commission did not approve a drilling plan, the Company would not participate in further drilling or costs associated with it. Put otherwise, this program is a series of five-year drilling plans, which the Commission can elect not to pursue each time a new plan is presented for review. And, as Mr. Benton noted, in addition to the right not to continue to participate in future drilling, existing drilling plans can be adjusted up or down as necessary.[168]

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[166] *Id*., Page 37, Lines 20-25, Page 43, Line 16 to Page 44, Line 1, Page 438, Line 21 to Page 439, Line 10.
[167] Hearing Ex. 101, Vancas Direct Testimony, Exhibit IV-1 (COSG Agreement), Section 4.4.
[168] Hearing Tr., Page 160, Line 13 to Page 161, Line 6, Page 226, Line 23 to Page 227, Line 9.

Intervenors are also incorrect in their assertion that Section 6.2 allows other participating utilities to essentially veto a decision to terminate the Company's participation in the COSG Program.[169] Section 6.2 does not state this. Rather, it provides, in relevant part:

> "Upon receipt of a termination notice, BHUH shall cause COSGCO to sell, as soon as practical, an interest in the Properties (but excluding any Property and/or wells for which the terminating Utility is a Non-Participating Utility) that is functionally equivalent to the terminating Utility's Percentage Share for the calendar year in which such sale(s) closes, *provided* that no sale(s) shall occur until the remaining Utilities ***have approved the <u>interest</u> to be sold*** and the terminating Utility has approved the sale price(s)."

(Emphasis added.) This provision requires that the remaining utilities "have approved the interest to be sold" not the sale itself, and the Company made clear in testimony and responses to discovery requests that this provision ***does not*** allow other participating utilities to veto any sale.[170] Rather, it simply recognizes that the remaining utilities are to affirm that "the interest to be sold" is appropriately sized to reflect the terminating company's participation in the COSG Program. In the face of this evidence from Black Hills (which drafted the COSG Agreement), intervenors cannot simply adopt their own interpretation and say that interpretation controls, particularly where they had no role in its drafting. If there was any doubt, Mr. Vancas made clear what Black Hills meant by the above provision and committed that it would not claim otherwise in the future.[171] This is not a legitimate objection to the Application, and should be disregarded.

10. <u>The Application Would Not Impact the Choice Gas Program, and if Black Hills Wanted to Expand the COSG Program to Choice Gas Areas, It Would Have to Seek Commission Approval to Do So</u>.

[169] *Id*., Page 93, Line 19 to Page 96, Line 24, Page 162, Line 8 to Page 165, Line 11, Page 374, Lines 14-20, Page 423, Lines 6-25.

[170] Hearing Ex. 116, Highly Confidential Vancas Rebuttal Testimony, Page 28, Lines 2-19; Hearing Tr., Page 95, Line 15 to Page 96, Line 24, Page 162, Line 8 to Page 165, Line 11; Hearing Ex. 216, Response to DR Request from Nebraska Public Advocate PA-11; Hearing Ex. 217, Response to DR Request from Nebraska Public Advocate PA-12.

[171] Hearing Tr., Page 95, Line 15 to Page 96, Line 24, Page 162, Line 8 to Page 165, Line 11.

As noted above, ACE challenges the COSG Program because of the concern that, in the future, if the program were expanded, it could cause ACE to lose customers to Black Hills either because Black Hills would seek to terminate the Choice Gas Program or because customers would want to transition to from that short-term hedging program for the benefits of the COSG Program, a long-term hedging program. Mr. Sorenson, on behalf of CNEG expresses a similar concern, although he couches it in alleged anti-competitive terms. Specifically, he claims the COSG Program "lacks definition on the terms and conditions regarding . . . customers' ability to transfer between" rate classes.[172] He also states that:

> "[J]ust as critical of a consideration is the adverse consequences to the viability of competitive markets if the requirements of the COSG program result in restriction to customer's freedom to select their preferred commodity provider and instead become captive to monopoly service. . . . If the COSG program is implemented there could be a very strong incentive for Black Hills to preclude residential customers from having a choice of their natural gas suppliers for decades into the future. . . . While expansion [of residential customer choice] requires Commission approval at [this] juncture, I am concerned the COSG program may have a chilling impact on residential customer choice expansion within Black Hills service as well as provide an incentive for future limitations being placed on existing SourceGas Gas Choice customers."[173]

No matter how these concerns are characterized, they are unjustified. The COSG Program, the COSG Agreement, and the Application do not seek in any way to impact existing rights for customers to transfer between transportation service and tariff service. Nor do they seek to implement the COSG Program in Black Hills' "SourceGas" territories. As Mr. Kilpatrick explained:

> "The COSG Program is clear that it would only impact tariff-rate customers who receive natural gas from the Company under the proposed revised tariff attached to my direct testimony. . . . The COSG Program would not impact (and does not request any changes that would affect) transportation customers, nor does it contain any provision that would impact customers' ability to transfer between

[172] Hearing Ex. 302, Sorenson Direct Testimony, Page 5, Lines 5, 7-8.
[173] *Id.*, Page 5, Lines 14-17, 19-21; Page 7, Lines 18-21.

customer groups."[174]

Similarly, in response to questions regarding the COSG Program's impact on the former SourceGas utilities, Mr. Vancas explained:

> "Well, I would say two things. Number one is should the Commission approve Phase 1 and even, Phase 2, we would not have the authority in any way, shape or form to expand the program to the former SourceGas utilities. That would require a separate proceeding before the Commission. . . . [T]his is not a SourceGas docket. There's nothing that happens in this docket that has any impact on the Choice gas program or the SourceGas utilities."[175]

He also added that, in the SourceGas docket, Black Hills committed that it would not disturb the Choice Gas program for three years and that nothing in the Company's Application seeks to impact the former SourceGas territories in any way.[176]

11. SourceGas' P0802 Contract Is Irrelevant to this Proceeding.

While not an insubstantial consideration as a general matter for utility operations in Nebraska, SourceGas' P0802 contract ("P0802") is not relevant to this proceeding and should not factor into any decision on the COSG Program. As even ACE concedes, P0802 was significantly different from the COSG Agreement.[177] Indeed, P0802 was not a hedging contract and was not intended to stabilize customer gas costs.[178] Rather, it was a contract entered into in the 1970s to ensure gas supply at a time when a guaranteed gas supply was of real concern, it contained a price adjustment clause that guaranteed the supplier the highest price in a given region, it allowed the supplier to drill as many wells as it desired, and it provided no way for the utility to exit.[179] By contrast, the COSG Agreement is a hedging contract meant ***to stabilize*** gas prices and further

[174] Hearing Ex. 120, Kilpatrick Rebuttal Testimony, Page 3, Lines 4-6, 10-12.
[175] Hearing Tr., Page 115, Lines 9-14; Page 117, Line 25 to Page 118, Line 3.
[176] *Id.*, Page 174, Line 16 to Page 175, Line 6.
[177] Hearing Ex. 400, Ackland Direct Testimony, Page 8, Lines 3-4; Hearing Tr., Page 57, Line 18 to Page 59, Line 17, Page 146, Line 19 to Page 148, Line 23.
[178] *Id.*
[179] *Id.*

benefit customers by avoiding the consequences of future price increases.[180] Drilling under the COSG Agreement is limited to the Commission-approved drilling plan, and it contains express provisions that allow the Company to exit at any time. And the Company seeks to implement the COSG Program at essentially the bottom of the market. Despite these monumental differences, intervenors nevertheless attempt to draw a comparison between them to dissuade the Commission from approving this Phase I proceeding. This is unfair and should be seen for what it is. P0802 and the COSG Program are apples and oranges, and no fair comparison can be made of them. Doing so is akin to comparing a contract to guarantee food supply during a famine with a contract to secure a low and stable price for food over the long-term. Furthermore, this is a Phase I proceeding and approval ***will not result*** in any commitment to implement the COSG Program.

VI. CONCLUSION

Nebraska customers are currently exposed to 100% of the risk of gas price volatility and price increases over the long term. To address these risks the Company asks the Commission to establish the scope, structure, and guidelines for a fully-transparent COSG Program in this Phase I proceeding. The primary benefit of the COSG Program is its ability to provide, at a reasonable price, greater rate stability than market prices by pegging customer gas costs to the stable and predictable costs of producing proven reserves. The Company believes, based on current market conditions, that an acquisition of a proven reserve under the COSG Program would provide customers with a stable price for the long-term at or very near [redacted] per Dth. Historical prices and independent forecasts indicate that at this price, the COSG Program would also result in customer savings over the course of the program. Plus, under the COSG Program Black Hills shareholders would assume some of the gas supply cost risk that is currently entirely borne by

[180] *Id.*

Nebraska customers. Intervenors hope that the Commission will not carefully review the evidence presented, but instead be swayed by their hand waving and fear mongering divorced from the record in this proceeding. In advocating that the Commission deny the Company's Application, marketer-intervenors are simply seeking to protect their own bottom line.

The Company is not asking in this Phase I proceeding that the Commission approve implementation of the COSG Program. Instead, a Phase I approval would give the Commission a non-binding free look at implementation with a specific property in a Phase II proceeding. In contrast, the Commission could miss the opportunity to protect Nebraska customers at a reasonable cost from gas supply cost risk over the long-term if it were to deny this Application. The Commission's consultant concluded that the "COSG Program is conceptually attractive, and worthy of serious consideration by the Commission."[181] The Commission has authority to approve the Company's Application, and the evidence in the record supports approval of the Application. The Company respectfully requests that the Commission approve the Application (with conditions if necessary), so that the Company can pursue opportunities to provide natural gas to its Nebraska customers at just and reasonable rates over the long-term and bring such opportunities back the Commission for review in Phase II.

Dated this 6th day of June, 2016.

[181] Hearing Ex. 4, Report of Commission Consultant Christensen Associates Energy Consulting, Page 7.

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CERTIFICATE OF SERVICE

I certify the foregoing was served on this 6th day of June, 2016 and that copies were served electronically as follows:

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