BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF NEBRASKA

In the Matter of the Application of	**)**	
Black Hills/Nebraska Gas Company, LLC	**)**	**Application No. NG-0086**
d/b/a Black Hills Energy for Approval of	**)**	
its Cost of Service Gas Hedge Agreement with	**)**	
Black Hills Utility Holdings, Inc.	**)**	

PUBLIC VERSION

REBUTTAL TESTIMONY OF

IVAN VANCAS

On Behalf of Black Hills/Nebraska Gas Utility Company, LLC, d/b/a Black Hills Energy
And
Black Hills Utility Holdings, Inc.

March 29, 2016

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Exhibits

I. INTRODUCTION AND QUALIFICATIONS

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. Ivan Vancas, 409 Deadwood Avenue, Rapid City, South Dakota 57702.

Q. FOR WHOM ARE YOU TESTIFYING?

A. I am testifying on behalf of Black Hills/Nebraska Gas Utility Company, LLC d.b.a. Black Hills Energy (the "Company").

Q. ARE YOU THE SAME IVAN VANCAS THAT PROVIDED DIRECT TESTIMONY IN THIS MATTER?

A. Yes.

II. PURPOSE OF REBUTTAL TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. In my rebuttal testimony, I respond to the Report prepared for the Commission by Christensen Associates Energy Consulting, LLC ("Christensen"), dated March 22, 2016 (the "Report"). In addition, I address in a general way the central concerns raised by the intervenors in this proceeding and offer the Company's reactions to those concerns. Finally, I respond in a specific way to certain matters raised in the direct testimony of Nebraska Public Advocate ("PA") witness Michael McGarry, Constellation NewEnergy - Gas Division, LLC ("CNEG") witnesses Stephen Bennett and Steve Sorenson, and Public Alliance for Community Energy ("ACE") witness Beth Ackland.

III. RESPONSES TO THE REPORT

Q. WHAT DID YOU FIND TO BE SIGNIFICANT IN THE REPORT?

A. While there are several aspects of the Report with which the Company disagrees, the Company and Christensen appear to agree on several fundamental issues related to the

COSG Program and the Company's Application. As an initial matter, the Report acknowledges the volatility of natural gas prices and notes that, due to that price variability, "there is good reason for distributors to hedge to natural gas prices, particularly beyond an annual timeframe."[1] Specifically, the Report concludes that, while short-term hedging practices can at times generate results that are less than expected due to various factors, hedging forward "can provide substantially more value, providing that metrics for measuring benefits of hedge programs are interpreted narrowly: to reduce the variation in costs, absent impacts on cost levels."[2] The Company agrees with these points. As noted in the Company's direct and rebuttal testimony, and in particular the rebuttal testimony of Ms. Ryan of Aether Advisors, spot market prices are highly volatile.[3] In addition, given the very low natural gas prices today, "prices are close to the break-even point" and "there is more potential for prices to rise than fall . . . ."[4] As such, "a strategy to hedge long-term gas prices would narrow the range of potential gas costs, thereby offering greater rate stability" and "the higher the percentage hedged, the more protection provided to the Company's customers against rising market prices."[5]

In addition, Christensen states that "BHC's proposed COSG Program is conceptually attractive, and worthy of serious consideration by the Commission."[6] The Company certainly agrees that the COSG Program, which has involved years of research, consideration, and consultation with Commissions, staff, and other stakeholders to develop,

[1] Christensen Associates Energy Consulting Report, March 22, 2016, Page 9.
[2] *Id.*, Page 10.
[3] Ryan Rebuttal Testimony, Pages 7-8.
[4] Ryan Direct Testimony, Page 19, Lines 14-16.
[5] Ryan Direct Testimony, Page 28, Lines 16-19.
[6] Christensen Associates Energy Consulting Report, March 22, 2016, Page 7.

is a program that will generate significant benefits for customers and, for that reason alone, is not only worthy of consideration, but should be approved.

Third, the Report acknowledges that the "[n]et present value (NPV) methods, utilized by Black Hills Nebraska in its filing before the Commission, constitutes the generally accepted analysis foundation underlying resource decisions."[7] While the NPV methodology and modeling presented in this Phase I proceeding has been submitted at this point for conceptual approval only, they are entirely consistent with the methodology generally used by the Company in making resources decisions. Moreover, they will be used to present a model to the Commission in the Phase II Proceeding, with actual costs and benefit calculations included, to allow the Commission to review and approve whether a specific reserve property should be included in the COSG Program.

Q. DO YOU AGREE WITH THE RECOMMENDATIONS OF THE REPORT AND, IF NOT, WHY NOT?

A. No, although my disagreement is as much with the process proposed in the recommendations as with their substance. In the Report, Christensen recommends that, while it finds "Black Hills Nebraska's COSG program conceptually viable, key empirical issues remain unresolved in the record."[8] Specifically, Christensen recommends that the Commission "set aside" the Company's Application "for the time being" pending subsequent proceedings to reach "resolution on two fundamental issues," namely (1) a quantitative analysis showing the benefits of the COSG Program, including "the methods

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[7] Christensen Associates Energy Consulting Report, March 22, 2016, Page 8.
[8] *Id.*, Page 18.

that would be employed for evaluating potential properties," "analytics to demonstrate how properties will be evaluated," and a quantitative analysis of costs and risks "using a set of relevant characteristics and attributes of sample properties"; and (2) an exploration of alternative arrangements for the sharing of risks and benefits, "measured in monetary terms."[9] This recommendation is not workable, as it would put the cart before the horse.

Christensen's desired quantitative analysis is essentially what the Company proposes to take place during the Phase II proceeding. That analysis cannot, as Christensen suggests, be conducted while the Phase I considerations of the scope, structure, level of participation, and other guidelines of the COSG Program are temporarily shelved. The only way to conduct an actual quantitative analysis "using a set of relevant characteristics and attributes," as Christensen seeks (which would in fact take place under the COSG Program as proposed) is to know the size, scope and guidelines of the COSG Program. This would include such things as how many utilities will be participating in the COSG Program and to what extent; the required characteristics, size and quality of the proposed reserve property; and what the program requirements and costs will be, etc. These are the very items the Company is asking the Commission to establish through this Phase I proceeding. Indeed, for this reason, Commissions and other stakeholders expressed the view that the COSG Program should be approached through the very two-stage process presented by the Company in its Application.

[9] *Id.*, Page 19.

IV. GENERAL RESPONSES TO INTERVENOR CONCERNS

Q. DO YOU HAVE ANY GENERAL RESPONSES TO THE RELEVANT CONCERNS RAISED BY THE PA WITNESS AND OTHER INTERVENORS?

A. Yes. I have carefully reviewed their direct testimony, which reflects certain common concerns Black Hills has heard from discussions with the intervenors in this proceeding and from the intervenors in the other five jurisdictions in which the COSG Program has been proposed. Those concerns relate to the following aspects of the proposed COSG Program: (i) hedging up to 50% of the Company's weather-normalized annual firm demand;[10] (ii) whether the 100 basis point deadband sufficiently balances risks between shareholders and customers;[11] (iii) the mechanism for calculating Allowed ROE;[12] (iv) the 60/40 equity to debt ratio;[13] (v) whether NYMEX Futures Contracts should be part of the Long-Term Market Price Forecast for Gas;[14] (vi) the risk that drilling and operating costs might increase;[15] (vii) whether 60 days is a sufficient period of time for Commission and stakeholder review of proposed acquisitions and Drilling Plans;[16] and (viii) intervenors' ability to timely retain outside support in connection with these reviews.[17] As described in the Company's rebuttal testimony, these concerns lack support and understanding of the COSG Program. The Company's application in this Phase I proceeding should be approved, in which case BHUH will work to implement the COSG Program, subject to

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[10] McGarry Direct Testimony, Page MJM-6, Line 19 to Page MJM-7, Line 1; Harms Direct Testimony, Page 8, Lines 15-16.
[11] McGarry Direct Testimony, Page MJM-19.
[12] *Id*., Page MJM-21, Line 9.
[13] *Id.*, Page MJM-21, Line 17 to Page MJM-22, Line 4.
[14] Bennett Direct Testimony, Page 13, Lines 14-15. Although commonly referred to as NYMEX Futures, the current technical name is Henry Hub Natural Gas Futures Contracts.
[15] McGarry Direct Testimony, Page MJM-19, Lines 15-16.
[16] *Id*., Page MJM-25, Line 20; *Id.*, Page MJM-28, Lines 12-19.
[17] *Id*., Page MJM-25, Lines 21-22; *Id.*, Page MJM-29, Line 4 to Page MJM-30, Line 12.

Commission review and approval in Phase II proceedings, so that customers can realize the benefits of a long-term physical hedge.

That being said, because the Company strongly believes that a long-term physical hedge is in customers' best interest, it would not object if the Commission required certain adjustments to the Company's proposed COSG Program to respond to intervenors' concerns. For example, Aether Advisors recommended hedging at least 35% with a goal of up to 50% of the Company's supply with a long-term physical hedge.[18] The Company has proposed the 50% level, but would not object if the Commission decided in this Phase I proceeding that a lower percentage, even down to 35%, was appropriate.

Q. IS THE COMPANY PROPOSING THAT LESS THAN 50% OF ITS SUPPLY BE HEDGED THROUGH THE COSG PROGRAM?

A. No. The Company continues to recommend that 50% be approved based on its analysis of the reserve prices, market conditions and the benefits of the COSG Program. However, in light of the stakeholders' concerns, particularly as they relate to the early years of the COSG Program, the Company would not object if the Commission decided that between 35% and 50% of the Company's weather-normalized annual firm demand should be hedged under the COSG Program.

Q. PLEASE CONTINUE.

A. With regard to the question of risk-sharing under the COSG Program, because the Company strongly believes that a long-term physical hedge is in customers' best interest and that customers will save money under the COSG Program over its term, it also would

[18] Ryan Direct Testimony, Page 31, Lines 6-7.

not object if the Commission decided that Black Hills should have more "skin in the game" and doubled the 100-basis point deadband to 200 basis points on either side of the Allowed ROE. Although this would decrease the risk of customers bearing Hedge Costs, in practice it will more likely decrease the Hedge Credits that customers receive. For that reason, the Company is not recommending this change. However, if the Commission decided it was in customers' best interest, the Company would not object.

Similarly, although the Company believes that its proposed mechanism for calculating the Allowed ROE is appropriate, the Company would not object if the Commission determined that only the average of gas utility rate cases reported by Regulatory Research Associates should be used to calculate the Allowed ROE (i.e., no use of electric utility rate cases).

In addition, concerning the capital structure, intervenors have suggested that the proposed capital structure should be closer to a 50/50 capital structure. While the Company believes its proposed structure is appropriate and justified, if the Commission decided that a 50/50 capital structure should be used rather than the proposed 60/40, the Company would not object.

Q. YOU ALSO MENTIONED INTERVENORS' CONCERNS ABOUT THE FORECASTS INCORPORATED INTO THE LONG-TERM MARKET PRICE FORECAST FOR GAS. PLEASE EXPLAIN.

A. NYMEX Futures Contracts do not offer good visibility to the direction of long-term market prices due to lack of trades beyond a few years.[19] For that reason, the Company does not

[19] Aether Report, Exhibit JMR-1, Pages 50-53.

believe that substituting NYMEX Futures Contracts for the Long-Term Market Price Forecasts for Gas under the COSG Program would be beneficial. However, because the Company believes the consideration of NYMEX Futures Contracts in the short-term can be helpful, the Company would not object if NYMEX Futures Contracts were averaged into the Long-Term Market Price Forecast for Gas in the following way: (i) for each of the first five years of a given Long-Term Market Price Forecast for Gas, the average of the then most recent NYMEX Futures Contracts, long-term [redacted] base case, and long-term EIA reference case were used; and (ii) the remainder of the Long-Term Market Price Forecast for Gas for years 5-20 would consist of the average of the then most recent long-term [redacted] base case and long-term EIA reference case.

Q. WHAT ABOUT THE RISK THAT DRILLING AND OPERATING COSTS MIGHT INCREASE FROM WHAT WAS ANTICIPATED, AS MR. MCGARRY TESTIFIED?[20]

A. As described in Mr. Benton's rebuttal testimony, within fields containing significant proven reserves, which the Acquisition Criteria of the COSG Program requires, drilling and operating costs are relatively predictable and stable.[21] However, assuming the Commission adopted a 200-basis point deadband, Black Hills would not be opposed to the Commission requiring in Phase II that BHUH consider mechanisms that would further minimize risks associated with these costs for customers' benefit. For example, BHUH would be amenable, for purposes of calculating Hedge Credits and Hedge Costs during the first three years of the first Drilling Plan, to proposing a cap on aggregate drilling costs to

[20] McGarry Direct Testimony, Page MJM-19, Lines 15-16.
[21] Benton Rebuttal Testimony, Page 2, Lines 8-9.

an average $/foot to be determined in the Phase II proceeding for that first property with typical industry adjustments like fuel-related costs. In that situation, Black Hills rather than customers would take on the risk that actual drilling costs exceed the agreed-to cap. In addition, the Company would not object to a limitation requiring that corporate general and administrative costs for that Drilling Plan be fixed in the Phase II proceeding with an inflation escalator. Furthermore, to address intervenors' concerns, the Company would not object to the Commission requiring three-year Drilling Plans rather than the proposed five-year Drilling Plans.

Q. WHAT ABOUT THE 60-DAY REVIEW PERIOD AND INTERVENORS' ABILITY TO TIMELY RETAIN OUTSIDE SUPPORT IN CONNECTION WITH THESE REVIEWS?

A. The Company continues to believe that these issues are appropriately addressed by the independent Hydrocarbon Monitor's role in the review process. Indeed, as noted below and in other direct and rebuttal testimony supporting the Company's positions, this timeframe has worked successfully for other cost of service gas programs. However, recognizing that expanding this timeframe may result is certain reserve opportunities being lost, the Company believes the following timeframes could allow some reserve opportunities to be pursued under the COSG Program: a 180-day review period for any proposed acquisition of a BHEP property, a 120-day review period for any proposed acquisition from an unrelated third-party provided that the third-party has agreed to such an extended review period [redacted] and a 120-day review period for updated Drilling Plans. Furthermore, BHUH would be willing to establish an escrow-like fund consisting of $250,000 that statutory customer advocates, such as the PA, could cooperatively utilize to timely retain or have on retainer additional outside support in connection with these reviews, to the extent they determined that such additional support were necessary. If these funds were not reimbursed by customer advocates, the Company would expect that they would be recovered through the COSG Program.

Q. HAS BLACK HILLS ALREADY MADE A DECISION TO PROPOSE INCLUDING ITS MANCOS SHALE ASSET IN THE COSG PROGRAM, AS MR. BENNETT ALLEGES?[22]

A. No. As the Company has reiterated both in its direct testimony and in its responses to a substantial number of data requests, no final decision has yet been made on any reserve opportunity. Furthermore, as explained above, no such decision could be made before this Phase I proceeding has been approved. Only then will the Company know the parameters and guidelines of the COSG Program and be able to assess whether any potential reserve property satisfies the Acquisition Criteria or will satisfy the other requirements of the approved program. It is true that, in discussions with analysts, Black Hills management has expressed a desire to consider BHEP assets for the COSG Program. Before any BHEP assets could be seriously considered, the parameters, requirements and economics of any such transaction would have to be determined under the COSG Program criteria as approved by the Commission.

[22] Bennett Direct Testimony, Page 18, Lines 6-7.

Black Hills believes its Mancos Shale asset in the Colorado Piceance Basin is a world-class asset that is ideally suited to realize customer benefits under the COSG Program. However, Black Hills is also mindful that the Acquisition Criteria in the COSG Agreement require that any sale from BHEP to COSGCO must be "fair based on other deals with unrelated third parties that are known in the market."[23] 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.

Black Hills could conceivably come back to the Commission in a Phase II proceeding with an option from BHEP under which the Company, subject to Commission approval, could cause COSGCO to acquire BHEP's existing Mancos wells and elect to start drilling additional wells within a certain period of time. In such a situation, customers would in effect purchase an option to secure drilling rights that could be exercised if prices increase (as the Company anticipates). If prices did not rise, the option would remain unexercised, and the Mancos properties would not be developed for the Company. Regardless of

[23] COSG Agreement, Exhibit A.

whether this or any other alternative would ultimately be pursued, the current environment offers COSGCO the opportunity to look to acquire properties from unrelated third parties to take advantage of the favorable price environment.

V. RESPONSES TO SPECIFIC MATTERS RAISED BY MR. MCGARRY, MR. BENNETT, MR. SORENSON, AND MS. ACKLAND

Q. IS MR. BENNETT CORRECT THAT THE COMPANY IS ASKING THE COMMISSION TO AUTHORIZE THE COSG PROGRAM "WITHOUT KNOWING WHICH RESERVE ASSET WILL BE SELECTED AND WITHOUT RECEIVING ANY INDICATIVE COST/BENEFIT MODEL FROM THE COMPANY?"[24]

A. No. Implementation of the COSG Program, as proposed, would involve a two-phase process. The first phase or filing, which we are currently engaged in, involves the approval of the general parameters of the COSG Program, which would include (a) permitting the Company to enter into the COSG Agreement, which would include an analysis of the capital structure and ROE (in the event the property is approved and the Program implemented); (b) approval of revised tariff sheets establishing the recovery mechanism for costs that would be incurred only after a property and Drilling Plan are approved in Phase II; (c) approval of the participation level of the Company in the COSG Program (in the event a property and Drilling Plan are approved and the COSG Program implemented); and (d) granting any waivers necessary to maintain compliance with affiliate rules and ring-fencing requirements. The Company is not requesting the recovery of any costs in this Phase I proceeding. This proceeding is merely to establish the mechanism, terms, and

[24] Bennett Direct Testimony, Page 6, Lines 2-3.

guidelines for a long-term cost of service gas hedging program. Cost recovery will be addressed in the Phase II proceeding.

Assuming the Commission approves the Company's Application in this first phase, the second phase filing will be made when the Company proposes a property and Drilling Plan that comply with the requirements of the COSG Agreement. At that time, the Company will provide the cost/benefit model based on the specifics of the proposed property and the then-current Long-Term Market Price Forecast. All stakeholders will be able to review the proposed property, the proposed drilling program, and the costs associated with the COSG Program. The Commission will determine if the Company will participate in the acquisition and Drilling Plan based upon the evidence presented in the Phase II proceeding. No costs or benefits will flow through the PGA based alone on the outcome of this Phase I proceeding.

Q. IS MR. MCGARRY CORRECT THAT THE ONLY RISK BORNE BY SHAREHOLDERS UNDER THE COSG PROGRAM IS THE RISK THAT THE ACTUAL RETURN ON EQUITY WILL FALL WITHIN 100 BASIS POINTS OF THE APPROVED ROE?[25]

A. No. While it is true that investors would bear 100% of the risk of any loss for the first 100 basis points below the Allowed ROE, in which case investors are not recovering their cost of capital, investors also have several additional risks: (1) As Mr. McKenzie discusses, because it is based on historical data, the Allowed ROE may fall below investors' required return on equity in an environment of rising capital costs; (2) if BHEP has a role as operator

[25] McGarry Direct Testimony, Page MJM-18, Lines 17-21.

for gas reserves owned by COSGCO, BHEP may have operational risks for which it will not be reimbursed under a joint operating agreement; (3) to the extent BHUH or COSGCO take actions that are not approved under the COSG Program, investors have the risk of being unable to recover the cost of such actions; and (4) Black Hills would be making long-term investments, and if regulators order utilities to cease participation in the COSG Program prematurely, Black Hills would bear significant financial and reputational risks flowing from that withdrawal.

Q. MR. BENNETT CLAIMS THAT IT WOULD BE ATYPICAL AND IMPROPER FOR THE COMPANY TO RECOVER ITS COSTS AND AN ROE FOR THE ACQUISITION OF NATURAL GAS RESERVES THROUGH THE PGA.[26] DO YOU HAVE A RESPONSE TO HIS CLAIM?

A. Yes. First, Mr. Bennett's characterization of the COSG Program is incorrect. Under the COSG Program, the Company (i.e., the regulated utility) ***would not be acquiring reserves***. Rather, BHUH, through COSGCO, would purchase and develop gas reserves with the gas produced being sold on the market. The proceeds from those sales will hedge the price exposure of the natural gas supply costs for the Company's customers. In addition, the ROE included in the calculation of Hedge Credits and Hedge Costs would not be an ROE paid to the Company. As discussed below, in the same way that third-party market producers receive a return on their invested capital through the gas they sell, Black Hills would receive a return on the equity it invests through COSGCO in purchasing the reserves for the COSG Program. Unlike those third-party market producers that receive an unregulated return, the return under the COSG Program would be regulated.

[26] Bennett Direct Testimony, Page 8, Lines 1-21.

Second, Mr. Bennett's analysis wholly ignores how gas purchased in the market includes un-capped profits for gas producers. While those profits are low or non-existent today because of low market prices, these profits can be very significant in higher-priced gas markets. His analysis fails to recognize that those costs are passed through directly to customers under the Company's current gas procurement approach. The COSG Program offers customers gas at a stable price with lower utility rates of return embedded in that price for up to half of the Company's gas portfolio.

Q. WHAT GAS COSTS FLOW THROUGH THE COMPANY'S PGA UNDER ITS CURRENT GAS PROCUREMENT APPROACH, AND WOULD INCLUDING HEDGE COST AND HEDGE CREDITS UNDER THE COSG PROGRAM MATERIALLY CHANGE THAT AS MR. MCGARRY ALLEGES?[27]

A. Under the current gas purchasing approach, the Company, through BHUH, meets its customers' gas needs by purchasing gas and managing gas price volatility through a mix of spot market purchases and short-term financial and physical fixed-price hedges. One-hundred percent of the commodity costs (including spot market purchases, hedging contracts, transportation costs, and storage costs) are passed through to customers through the Company's PGA. Because of this, the Company already routinely conducts hedge settlements that result in hedge costs and hedge credits being passed along to customers.

Q. DOES THE PRICE OF GAS THAT THE COMPANY CURRENTLY FLOWS THROUGH ITS PGA INCLUDE A RETURN TO UPSTREAM PARTICIPANTS?

A. Yes. When a producer sells gas in the market, the producer receives a return on capital invested for producing gas. The amount of the return depends upon the embedded costs

[27] McGarry Direct Testimony, Page MJM-19, Line 3.

relative to the price received. As noted by Mr. McKenzie, due to the risks assumed by gas reserve owners and producers, this ROE will typically be higher than utility ROEs. Consequently, when the Company purchases gas from the market, customers are, in reality, already paying a rate of return.

Q. WHAT ARE ALL OF THE COST COMPONENTS THAT CUSTOMERS PAY TODAY FOR THE GAS THAT IS PROCURED FOR THEM BY BHUH FROM THE MARKET?

A. Producers selling gas in the market are seeking to recover their costs of exploration, production, operational and marketing costs, production taxes, as well as royalties they incur to bring the gas to market. Essentially these are the same cost components that are proposed to be recovered in the COSG Program, with the exception of exploration costs.

Q. IS THERE A DIFFERENCE BETWEEN COSGCO AND THIRD-PARTY MARKET PRODUCERS THAT WOULD JUSTIFY DENYING A RETURN ON INVESTED CAPITAL IN THE COSG PROGRAM?

A. No. The same rationale that justifies third-party reserve owners or producers, or a counterparty to a hedge agreement, to expect a return on invested capital is equally applicable to COSGCO under the COSG Program. While it is true that typical exploration and production companies take the risk that their production costs will be low enough relative to market prices to realize their desired rate of return, the result is that they build that risk into their business models and would not invest in projects that are not anticipated to return a multiple of utility rates of return over the life of the reserves. An advantage of the COSG Program is that any return received above the Allowed ROE plus 100 basis points accrues to the benefit of customers.

Q. IF THE COMPANY INVESTED CAPITAL TO PROCURE GAS RESERVES DIRECTLY, WOULD IT RECEIVE AN ROE ON THOSE INVESTMENTS?

A. Yes, assuming the Commission determined the investment was appropriate. As is generally the case, when the Company prudently invests capital in its utility services, the Commission authorizes an ROE on that invested capital. Here, the COSG Program, rather than having the Company purchase the reserves directly, would have COSGCO purchase the reserves to maximize tax benefits for customers and realize administrative efficiencies.[28] Having COSGCO purchase the reserves instead of the Company to obtain these benefits is not a justification for denying an appropriate ROE. COSGCO exists only for the purpose of providing a service to utility customers. Its activities will be 100 percent utility related. See Section 4.1 of the COSG Agreement. Consequently, the Company would expect that the COSG Program should be allowed a utility-like return on the capital invested for the COSG Program.

Q. MR. BENNETT, MR. MCGARRY, AND MS. ACKLAND CLAIM THAT THE COSG PROGRAM WOULD TRANSFER RISK FROM SHAREHOLDERS TO RATEPAYERS.[29] DO YOU AGREE?

A. No. In arguing that the COSG Program shifts risks to customers from shareholders, Mr. Bennett, Mr. McGarry, and Ms. Ackland do not acknowledge that the very risks they raise are risks already borne by customers. As noted above, under the current gas purchasing approach, 100% of the commodity costs (and hedging costs, transportation costs, and storage costs) as well as the associated returns to producers and marketers are passed

[28] Carr Direct Testimony, Page 17, Line 15 to Page 18, Line 11; Vancas Direct Testimony, Page 18, Lines 7-13; *Id.*, Page 22, Lines 14-21.

[29] Bennett Direct Testimony, Page 8; McGarry Direct Testimony, Page MJM-7; *Id*. Page MJM-18; *Id*. Page MJM-44; Ackland Direct Testimony, Page 6.

through to customers through the Company's PGA. The COSG Program is targeted at stabilizing gas prices and minimizing the volatility of those costs. It does not seek to transfer risks to customers but rather mitigate existing risks.

Q. DO YOU AGREE THAT MR. BENNETT'S HYPOTHETICAL SCENARIO DEMONSTRATES THAT THE COSG PROGRAM TRANSFERS RISK FROM BLACK HILLS' SHAREHOLDERS TO CUSTOMERS?[30]

A. No. As noted, over the long-term, the prices paid by customers for market purchases already incorporate the costs Mr. Bennett discusses. Under the way gas is currently procured, customers essentially bear 100 percent of all risks associated with those gas purchases. Under the COSG Program, some of those risks are shifted to Black Hills' shareholders. The only difference created by the COSG Program is that it changes ***the source*** of those pass-through costs and limits the potential return to a utility-like return. Instead of coming from another producer, the costs would be passed through at +/- 100 basis points around an Allowed ROE. And, COSGCO, as a participant in the COSG Program, would have greater control over the management of those costs than would exist with an unrelated gas producer, and COSGCO's operations would be transparent to the Commission compared to an unrelated third-party.

With regard to supply risk (i.e., the risk that supply volumes will not meet forecasted supply volumes), Mr. Bennett's analysis is similarly flawed. First, the COSG Program minimizes the risk that volumes will not meet forecasted volumes by requiring any acquisition to meet the Acquisition Criteria of Exhibit A to the COSG Agreement. In particular, as noted, the

[30] Bennett Direct Testimony, Page 10.

agreement requires any acquisition to be comprised of at least 50% proved developed producing reserves ("PDPs") and 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."[31] Second, even beyond these protections, the first 100 basis points of any loss resulting from underperformance in the COSG Program would be borne exclusively by Black Hills' shareholders, not customers.

Q. MR. MCGARRY, MR. BENNETT, AND MS. ACKLAND STATE THAT, INSTEAD OF OFFERING AN OPPORTUNITY TO EARN AN APPROVED RETURN LIKE REGULATED UTILITIES, THE COSG PROGRAM GUARANTEES RECOVERY OF PROGRAM COSTS AND A RETURN ON RESERVE ASSETS.[32] DO YOU AGREE?

A. The intent of the COSG Program is to have a portion of customers' gas be priced at the cost of production, with a utility-like rate of return, rather than having all of the gas be subjected to the volatility inherent in the law of supply and demand of the natural gas commodity. The program as proposed, does that. Mr. McGarry, Mr. Bennett, and Ms. Ackland ignore the fact that Black Hills' shareholders are assuming some gas supply risk, where they did not before. In exchange Black Hills' shareholders would have the opportunity to earn a utility-like rate of return. Mr. McGarry, Mr. Bennett, and Ms. Ackland do not acknowledge that commodity costs and an expected return are already reflected in the gas costs paid by customers under the Company's current gas procurement approach. Moreover, as with any other utility operation, under the COSG Program, there

[31] COSG Agreement, Exhibit A.
[32] McGarry Direct Testimony, Page MJM-18, Lines 8-14; Bennett Direct Testimony, Page 3, Lines 23-24; *Id.*, Page 4, Lines 10-17; Ackland Direct Testimony, Page 7, Lines 12-14.

is no "guaranteed" recovery of all costs, nor is there a guarantee that the actual earned ROE under the COSG Program will match the cost of capital. If the Commission approves the COSG Program, costs that are incurred consistent with the approved COSG Program and COSG Agreement would be recoverable in the same way costs incurred by the Company for proper utility operation are recoverable by the Company in its revenue requirement today. If costs were incurred that were not proper under the COSG Agreement, they would not be recoverable. Furthermore, in addition to any input requested by the Commission throughout the year, the Commission will receive an annual report from the Hydrocarbon Monitor and an annual assurance report from the Accounting Monitor, which the Commission can use to monitor the COSG Program.

Q. IS IT TRUE, AS MR. MCGARRY SUGGESTS, THAT A DRILLING PLAN COULD BE AMENDED AT ANYTIME DURING THE PLAN WITH ONLY HYDROCARBON MONITOR APPROVAL?[33]

A. No. A Drilling Plan could be amended at any time, but that would require Commission approval.[34]

Q. DO YOU HAVE A RESPONSE TO MR. MCGARRY'S CONCERNS ABOUT THE COMMISSION'S OR THE PA'S ABILITY AND RESOURCES TO REVIEW, AND IN THE CASE OF THE COMMISSION APPROVE, RESERVE ACQUISITIONS AND DRILLING PLANS?

A. Yes. Mr. McGarry claims that the Company has acknowledged that the Commission and the PA lack the expertise to make educated recommendations regarding proposed

[33] McGarry Direct Testimony, Page MJM-28, Lines 15-16.
[34] COSG Agreement, Section 4.3.

acquisitions or drilling plans.[35] His statement is incorrect. While he quotes, in part, a data request served by the PA, he does not quote the response. Rather, he claims to paraphrase the response by stating that the Company "acknowledged the lack of expertise ...."[36] Contrary to Mr. McGarry's assertion, the actual request and response are as follows:

> **REQUEST NO. PA-33:**
>
> Does Black Hills believe that approval of reserve acquisitions and drilling plans is within the Commission's and the PA's expertise? Does Black Hills expect the Commission and the Parties to contract for such expertise, or are the Hydrocarbon Monitor and Accounting Monitor intended to fulfill such needs?
>
> **RESPONSE:**
>
> The Company is not fully aware of the extent of the Commissions' or the PA's familiarity or experience with reserve acquisitions or drilling plans. However, as described in the direct testimony of Mr. Carr, Page 6, where Commissions, Boards and Consumer Advocates may lack the personnel with technical expertise and experience with natural gas production to monitor each aspect of the functions of the COSG Program and/or to evaluate and approve reserve acquisitions, the COSG Program incorporates assistance for the Commission, its staff, and consumer advocates. Specifically, not only will the Independent Hydrocarbon Monitor provide support and expertise regarding natural gas reserve reports, acquisitions, and drilling plans, but the Accounting Monitor will also provide an annual report regarding the financial operations of the program. In the case of a proposed reserve acquisition, the Company would provide the Commission with a report from the Independent Hydrocarbon Monitor advising whether the proposed acquisition and associated drilling program satisfies the Acquisition Criteria. Similarly in the context of the five-year drilling plan review, the Company would provide the Commission with a report from the Independent Hydrocarbon Monitor advising whether it satisfies the Drilling Plan Criterion.
>
> The Commission and the Parties could also choose to contract for expertise in addition to the Independent Monitors at their discretion.[37]

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[35] McGarry Direct Testimony, Page MJM-29, Lines 4-11.
[36] *Id.*, Lines 10-11.
[37] Response to Data Request No. 33, January 22, 2016.

The point the Company was making in its response was that the COSG Program incorporates a mutually-acceptable and qualified professional Hydrocarbon Monitor precisely to provide independent expertise to help the Commission and intervenors in a Phase II proceeding assess acquisitions and drilling plans, obviating the need for other specific experience. This same approach was implemented in Utah and Wyoming with the Questar/Wexpro cost of service gas program, which has successfully used a hydrocarbon monitor for that very purpose. In 2013, that program was reapproved, including the use of a hydrocarbon monitor to assist the commissions and consumer advocates in Utah and Wyoming to assess acquisitions and drilling plans.[38] The subsequent history in Utah and Wyoming indicate that this approach can work for Commissions and consumer advocates.

Q. DO YOU AGREE WITH MR. MCGARRY AND MR. BENNETT THAT THE MONITORS WOULD NOT BE INDEPENDENT UNDER THE COSG PROGRAM BECAUSE THEY ALLEGEDLY ARE NOT SELECTED BY THE COMMISSION OR ARE PAID BY BLACK HILLS?[39]

A. No. While acknowledging that it is "quite common for Commissions" to rely on hired specialists or auditors with expertise to review utility functions and advise the Commissions on issues before them,[40] Mr. McGarry attempts to distinguish the Monitors under the COSG Program from other experts hired by the Commission. The basis of his attempted distinction is his claim that other experts are "selected" by the Commission whereas the Monitors would only be "approved" by the Commission.[41] Mr. McGarry's

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[38] Memorandum Opinion, Findings and Order Approving the Wexpro II Agreement, Wyoming Public Service Commission, Docket No. 30010-123-GA-12 (Record No. 13347) (attached as Exhibit IV-5); March 28, 2013, Report and Order, Public Service Commission of Utah, Docket No. 12-057-13 (attached as Exhibit IV-6).
[39] McGarry Direct Testimony, Page MJM-29-30; Bennett Direct Testimony, Page 25, Lines 14-17.
[40] McGarry Direct Testimony, Page MJM-29, Line 20 to Page MJM-30, Line 4.
[41] *Id.*

characterization does not reflect the terms of the COSG Agreement and is a distinction without a difference.

While Section 2.1 of the COSG Agreement states that the Monitors would be retained by BHUH, the intent of this provision was not to communicate that the Commission would not participate in selecting the Monitors or that the Monitors would not be serving the Commission. Indeed, nothing in the COSG Agreement or testimony in this proceeding states that the Commission would not participate in ***selecting*** the Monitors or prohibiting them from contacting or initiating contact with the Monitors. In fact, Section 2.1 of the COSG Agreement requires that the Monitors be acceptable to the Commission. Further, the COSG Agreement also requires that the Monitors be accountable to the Commission, provide assistance as needed to the Commission, and that the Commission would have access to all information from the Monitors at any time.[42] Even though the Monitors will be paid through the COSG Program, as licensed or registered professionals, they would be subject to additional ethical standards requiring them to be independent. Thus, the inclusion of the Monitors is not a risk for customers or the Commission. It is a benefit and a protection.

Q. MR. MCGARRY TAKES ISSUE WITH THE 60-DAY REVIEW PERIOD TO EVALUATE ACQUISITIONS OR DRILLING PLANS.[43] HOW DO YOU RESPOND?

[42] COSG Agreement, Sections 2.2 and 2.3.
[43] McGarry Direct Testimony, Page MJM-7, Lines 14-16.

A. Sellers of reserves generally cannot wait more than a month or two for regulatory approval to consummate a transaction as market prices for natural gas fluctuate, and those fluctuations impact reserve valuations. A similar 60-day expedited approval process has been implemented and used by the Wyoming and Utah Commissions for the Wexpro cost of service gas program.[44] In addition, under the COSG Program, the Company is willing to ask a prospective seller if it would extend the time frame for regulatory approval while keeping the negotiated terms. However, if the seller refuses, the Company would request a decision within the 60-day expedited deadline. Mr. McGarry acknowledges the Company is willing, subject to adequate protection of confidentiality, to provide the Hydrocarbon Monitor access to all diligence information, including access to the seller's data, to provide advanced access to data and information as it is developed prior to the Hydrocarbon Monitor's report being due. Finally, the Company would provide the Commission with a report from the independent Hydrocarbon Monitor advising whether the proposed acquisition satisfies the Acquisition Criteria. This same approach would be followed for subsequent Drilling Plans prior to the Hydrocarbon Monitor's report.

Because the Commission would have already approved the structure of the COSG Program (the benefit of a two-phase approach discussed above), Black Hills believes that a proceeding focused on a specific reserve acquisition and drilling plan, supported by its filing and the report from the independent Hydrocarbon Monitor, will provide sufficient

[44] Memorandum Opinion, Findings and Order Approving the Wexpro II Agreement, Wyoming Public Service Commission, Docket No. 30010-123-GA-12 (Record No. 13347) (attached as Exhibit IV-5); March 28, 2013, Report and Order, Public Service Commission of Utah, Docket No. 12-057-13 (attached as Exhibit IV-6); November 17, 2015, Order Approving Stipulation, Public Service Commission of Utah, Docket No. 15-057-10 (attached as Exhibit IV-7).

time for the Commission to make a decision with respect to a proposed property and initial drilling plan.

Q. IS MR. MCGARRY CORRECT WHEN HE STATES THAT THE "COMPANY, TO THIS POINT, HAS REFUSED TO DISCLOSE HOW MANY POTENTIAL ACQUISITIONS MAY BE IN THE FIRST PLAN?"[45]

A. No. It is likely that only one acquisition would be part of any Phase II proceeding if the Commission approves the COSG Program. The Company has not refused to disclose any potential acquisitions, and Mr. McGarry does not identify any instance to support his claim. As explained in my direct testimony and as the Company has repeatedly explained to the PA and others, before a reserve acquisition could be pursued and the specific details of such an acquisition can be known (whether it be the purchase of reserve property or another kind of arrangement, such as a drill-to-earn program), Black Hills must first know the COSG Program parameters established in this Phase I proceeding. These would include the acquisition and drilling guidelines that will be required by the Commissions in the states where utilities will be participating, the number of utilities participating in the COSG Program, the percentage of each participating utility's firm demand that would be included in the COSG Program, and a number of other factors that could impact the size, scope or nature of the COSG Program. Without this information, Black Hills cannot determine the amount of needed reserves, the investment required to acquire those reserves, the size, scope or timing of drilling programs, and other operational information that would be part of any due diligence process.

[45] McGarry Direct Testimony, Page MJM-30, Lines 21-22.

In meetings with interested parties prior to the filing of the Company's Application, the specific suggestion was made to file for approval in a two-stage process, as the Company has done, precisely to avoid putting the cart before the horse. The Company believes there is wisdom in staging the proceedings in this fashion, and specifically did so to provide the Commission and interested parties with the opportunity first to address in a specific and focused way the structure and components of the COSG Program and the COSG Agreement. Indeed, the same two-phase approach was approved by both the Utah Public Service Commission and the Wyoming Public Service Commission when they approved the Wexpro cost of service gas program that it is effect in those states.[46]

As discussed above, the second phase will address in a specific and focused way any proposed acquisitions or Drilling Plans within the confines of the COSG Program and COSG Agreement, assuming that the Commission approves the Company's Application in this proceeding.

Q. MR. MCGARRY IS ALSO CONCERNED THAT THE MULTI-JURISDICTIONAL APPROVAL PROCESS COULD RESULT IN THE COMPANY "SHOULDER[ING] THE BURDEN OF THE COSTS THAT WOULD HAVE BEEN ALLOCATED TO AND PAID" BY UTILITIES THAT DO NOT RECEIVE APPROVAL TO PARTICIPATE IN THE COSG PROGRAM.[47] IS HIS CONCERN JUSTIFIED?

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[46] Memorandum Opinion, Findings and Order Approving the Wexpro II Agreement, Wyoming Public Service Commission, Docket No. 30010-123-GA-12 (Record No. 13347) (attached as Exhibit IV-5); March 28, 2013, Report and Order, Public Service Commission of Utah, Docket No. 12-057-13 (attached as Exhibit IV-6); November 17, 2015, Order Approving Stipulation, Public Service Commission of Utah, Docket No. 15-057-10 (attached as Exhibit IV-7.

[47] McGarry Direct Testimony, Page MJM-37, Lines 15-16.

A. No. With respect to this Phase I proceeding, if the Commission approves the Company's participation in the COSG Program, but another Black Hills utility did not receive such approval from its respective board or commission, the Company's customers will not bear the costs associated with the Phase I proceeding in that other state. One of the reasons the Company is seeking approval in this two-phased approach is to understand ***before any acquisitions are pursued*** which utilities will be participating and to what extent in the COSG Program so that acquisitions and associated Drilling Plans can be appropriately scaled.

With respect to Phase II, the due diligence costs for a proposed property will be proportionately allocated amongst the utilities that receive a Phase I approval. If the Commission approves a Phase II application for a particular property, but the board or commission in another state does not approve that Phase II application, the due diligence costs allocated to that non-participating utility will not be included in the calculation of Hedge Credits and Hedge Costs for the Company.

For these reasons, Mr. McGarry's concerns are not justified, and his hypothetical is inaccurate.

Q. MR. MCGARRY CLAIMS THAT THE TERMINATION PROVISION OF THE COSG AGREEMENT USURPS THE COMMISSION'S AUTHORITY.[48] DO YOU AGREE?

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[48] McGarry Direct Testimony, Pages MJM-41-43.

A. No. Mr. McGarry misstates what is contained in the termination provision and the Company's position relative to that provision. As an initial matter, Mr. McGarry misinterprets one phrase of Section 6.2. He seizes on the phrase underlined in the quoted language below from Section 6.2 and claims that it "makes it clear that one or more of the utilities could negate any potential sale transaction":[49]

> 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 interest to be sold and the terminating Utility has approved the sale price(s).

Mr. McGarry's statement is incorrect. The underlined statement ***does not say*** that the remaining utilities could prevent the sale of an interest. Rather, it states that before the sale occurs, the remaining utilities must approve ***the interest*** being sold. In other words, this provision is included solely to ensure that the reserve interest being sold is properly associated with the terminating utility's interest in the COSG Program. Once that magnitude and character of that interest has been approved, it can be sold, and no other utility could prevent that sale from proceeding.

Second, Mr. McGarry's description of the Company's position relative to the termination provision is incorrect. Nothing contained in the COSG Agreement's termination provision would alter the Commission's authority, nor is Black Hills seeking to do so. Rather, the termination provision simply recognizes the reality that exists for a party terminating its interest in a contract. Specifically, a party given a right to terminate a contract normally is

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[49] *Id.*, Page MJM-42, Lines 14-15.

also required to fulfill any then-existing obligations. For instance, if the Commission approved the Company to execute a hedging contract or a long-term gas contract, the Commission could order the Company to prematurely terminate that contract, assuming such termination was permitted, but the Commission's order would not exempt the Company from any duty it then had to pay any amounts owing under the contract or any early termination charges. The same is true under the COSG Agreement. Section 6.2 recognizes that the Commission could order the Company to terminate its participation in the COSG Agreement, but the terminating utility would still be required to fulfill any existing obligations, including any obligations to pay amounts owing under the COSG Agreement. This does not alter the Commission's authority. Rather, it is a recognition that the Company incurred an obligation that it has to fulfill or account to other parties. However, unlike some contract terminations, there will be a value to the reserve interests allocated to the Company for participation in the COSG Program and the proceeds from the sale of those reserve interests will offset the amounts owed under the COSG Program and may potentially result in an additional credit to customers.

Given the foregoing, it is unfair for Mr. McGarry to characterize the Company's position as rigid or unconventional. On the contrary, as is true for all or nearly all of the Company's contracts with third parties, the Company has to fulfill its obligations under those contracts or address any damages from its failure to do so.

Q. MR. BENNETT CLAIMS THAT THE COSG PROGRAM IS SEEKING TO HAVE CUSTOMERS TAKE ON RISK THAT BLACK HILLS IS UNWILLING TO UNDERTAKE.[50] HOW DO YOU RESPOND TO THIS CLAIM?

A. First, I disagree that the COSG Program seeks to impose on customers or does in fact impose on customers the risks that Mr. Bennett claims. On the contrary, customers are already exposed to some or all of those risks. The COSG Program reduces customer exposure to many of those risks while providing long-term price protection for customers. Second, as with any large capital investment in assets for the benefit of utility customers, the costs for providing those benefits should be borne by the customers who receive those benefits. The COSG Program is a hedge for the customers' benefit and as with any other hedge entered into by or for the Company, the customers bear the cost and reap the benefits of that hedge. Third, the statement in and of itself does not make sense because Black Hills is not attempting to hedge its own gas costs; rather, it is attempting to provide a physical hedge to customers for their gas costs. Black Hills, through its BHEP subsidiary, already owns and has rights to physical reserves for the benefit of its shareholders. Finally, under the current methods for procuring natural gas for customers, all prudently incurred costs are passed through to customers through the PGA and the Company bears no risk. Under the COSG Program, Black Hills will take the risk of having its approved ROE for the program reduced by up to 100 basis points: a risk Black Hills currently does not have.

[50] Bennett Direct Testimony, Page 12, Line 6 to Page 13, Line 2.

Q. MS. ACKLAND RAISES THE BOWDOIN FIELD GAS OBLIGATION ENTERED INTO BY SOURCEGAS AS AN EXAMPLE OF WHY THE COMMISSION SHOULD BE CONCERNED ABOUT THE COSG PROGRAM.[51] HOW DO YOU RESPOND?

A. As an initial matter, Ms. Ackland acknowledges, and I agree, that "there are significant differences between" the two matters.[52] Most significantly, the COSG Program seeks to set a stable hedge price by purchasing gas reserves at recently unprecedented low prices. As such, production costs under the COSG Program would likewise be correspondingly low, resulting in low and stable gas prices for customers. In addition, the drilling programs are subject to Commission review every five years, allowing the Commission to elect not to participate in further drilling at any of those points. The same right did not exist in the Bowdoin Field gas arrangement. Moreover, the $8/dekatherm cost of gas from the Bowdoin Field arrangement is significantly higher than the anticipated cost of gas under the COSG Program.

Q. ACCORDING TO MR. SORENSON, THE COSG PROGRAM "PLACES FUTURE PRICE RISK CLEARLY ON THE RATEPAYER, WHEREAS THE COMPETITIVE MARKET OFFERS CONSUMERS CONTROL OVER PRICE RISK THROUGH AN ARRAY OF PRODUCTS AND SERVICES AVAILABLE IN THE MARKET."[53] DOES THE COSG PROGRAM INTRODUCE ANY ADDITIONAL RATEPAYER PRICE RISK THAT IS NOT ALSO PRESENT IN

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[51] Ackland Direct Testimony, Page 7, Line 17 to Page 8, Line 6.
[52] *Id.*, Page 8, Lines 3-4.
[53] Sorenson Direct Testimony, Page 14, Line 22 to Page 15, Line 2.

THE SO-CALLED "COMPETITIVE MARKET" DESCRIBED BY MR. SORENSON IN HIS DIRECT TESTIMONY?

A. Absolutely not. It is difficult to understand Mr. Sorenson's logic that, on the one hand, selling natural gas produced by COSGCO into the market increases price risk, yet buying natural gas in the market does not. As noted above, customers bear all the price risk today. True, short-term hedging has reduced the impact of price volatility and mitigated the commodity cost increases from one season to the next, but that is all. Short-term hedges and "other mechanisms" offered by marketers leave customers exposed to longer term increases in gas prices. Future spot market purchases and short-term hedges will have to follow rising prices absent a longer term hedge. However, the COSG Program would offer greater price stability. Under the COSG Program, 50% of future gas supply costs would be hedged and stabilized for an extended period of time, and done so at a point in time when market prices are very low. COSGCO would buy reserves for the benefit of the COSG Program, and the acquisition price of those reserves would be known at the time a property is proposed to be included in the COSG Program. The remaining factors that determined the produced cost of gas will primarily be the cost to drill and operate each well, gathering and processing, and taxes. Those costs will be significantly more stable and predictable than competitive market prices.

Q. MR. SORENSON CLAIMS THAT COSG PROGRAM "CONFLICTS WITH A COMPETITIVE MARKETPLACE" BECAUSE IT MAY RESULT IN STABLE PRICING THAT IS LOWER THAN MARKET PRICES AND CREATE A "NON-

LEVEL PLAYING FIELD" FOR COMPETITIVE SUPPLIERS.[54] HOW DO YOU RESPOND TO THIS CLAIM?

A. First, Mr. Sorenson acknowledges that the "protection of retail suppliers against below market prices is not, per se, the concern or responsibility of the Commission."[55] I agree with Mr. Sorenson on this point. The Commission's mandate is to ensure that customers pay just and reasonable rates, not that they pay rates equal to the rates charged by competitive natural gas suppliers. As noted by the Commission's consultant, Christensen Associates, the mere fact that the COSG Program could result in retail gas prices at below market rate and because market competitors may lose business is not a legitimate reason for the Company not to propose the COSG Program for the benefit of its customers. Christensen Associates notes that while the COSG Program may convey cost advantages, it does not find the potential realization of any such advantage to be unfair.[56]

Second, the COSG Program is not designed to provide nor remove opportunities for retail suppliers to grow or maintain their market share. Also, the COSG Program is not designed to compete with retail suppliers who have transportation customers. The COSG Program is designed to provide a long-term physical hedge for natural gas costs with a reasonable opportunity for savings for system supply (tariff gas) customers over the life of the reserves. Competitive natural gas suppliers currently sell natural gas to Nebraska customers under the Company's transportation tariffs on file with the Commission. Customers that are eligible for transportation service are free to choose any supplier for

[54] Sorenson Direct Testimony, Page 11, Lines 8-15.
[55] *Id.*, Page 11, Lines 16-17.
[56] Christensen Associates Energy Consulting Report, March 22, 2016, Page 16.

natural gas and that will continue to be the case if the COSG Program is approved by the Commission as proposed. Nothing in the COSG Program prevents suppliers from developing their own programs to attempt to provide a variety of supply and pricing options to transportation customers at prices competitive to the COSG Program.

Third, it strikes me that, if the COSG Program makes competitive gas suppliers nervous that they might lose customers to better pricing and hedging benefits under the COSG Program, the program is worthy of implementation. Mr. Sorenson clearly believes that CNEG's offerings may be less attractive to customers than the COSG Program, and wants the Commission to deny customers the advantages of the COSG Program.

Fourth, Ms. Ackland, on behalf of another competitive supplier, acknowledges that the COSG Program would have "no immediate impact to ACE or its customers from approval of [the Company's] application. . . ."[57]

Q. MS. ACKLAND CLAIMS THAT "STATEMENTS MADE IN BKH ANALYST DAY MATERIALS AND OTHER MATERIALS . . . INDICATE BLACK HILLS' FUTURE INTENT TO EXPAND THE [COSG] PROGRAM TO CURRENT SOURCEGAS TERRITORIES" AND THAT BLACK HILLS DOES NOT VIEW THE COSG AND CHOICEGAS PROGRAMS "AS ABLE TO CO-EXIST." DO YOU HAVE A RESPONSE TO THESE CLAIMS?

A. Yes. First, this Phase I application is only for Black Hills legacy utilities (i.e. the Black Hills utilities in 5 other states as of Fall 2015). It does not include the former SourceGas

[57] Ackland Direct Testimony, Page 8, Lines 9-10.

areas in which the ChoiceGas Program is available. Second, Black Hills has agreed that should it desire to change the ChoiceGas Program, it can only do so with separate applications to each state Commission and only after working collaboratively with interested parties and after the 2018/2019 ChoiceGas enrollment period unless mutually agreed to by the parties. It is premature to discuss and debate Ms. Ackland's concerns when the Company is not seeking in this Phase I application to expand the COSG Program into ChoiceGas areas.

Q. CITING TO DIRECT TESTIMONY BY COMPANY WITNESSES VANCAS AND CARR, MR. SORENSON ASSERTS THAT BLACK HILLS IS UNWILLING TO INVEST IN ASSETS OR DRILLING WITHOUT THE COSG PROGRAM BECAUSE HE CLAIMS BLACK HILLS IS NOT HIGHLY CONFIDENT THAT ITS FUTURE E&P COSTS WILL BE NOTABLY LOWER THAN FUTURE NATURAL GAS PRICES.[58] IS MR. SORENSON CORRECT?

A. No. Mr. Sorenson mischaracterizes the cited direct testimony. What the direct testimony actually states is that Black Hills cannot invest in COSG Program assets until it knows the final structure and terms of the COSG Program as approved by the Commission and the other respective Boards and Commissions. For example, Black Hills would not know even the magnitude of the reserves COSGCO would need to purchase until it knows the level of participation by each utility in the COSG Program. Moreover, it would not make sense for Black Hills to invest in reserves for the purpose of creating a long-term physical hedge for customers' gas costs if it did not have a reasonable assurance that the Commission would approve such a program after the reserves were acquired.

[58] Sorenson Direct Testimony, Page 12, Lines 6-11.

If Mr. Sorenson is questioning Black Hills willingness to invest through BHEP strictly as an independent exploration and production company, that is a separate matter and not an issue in this proceeding. BHEP, like other producers, has higher return targets than that proposed for the COSG Program to satisfy shareholders' expectations for that business. BHEP has, like most other exploration and production companies, held back its investment in drilling new wells under the current spot market price environment because of the difficulty in reaching satisfactory returns for an E&P company.

The COSG Program offers an opportunity to acquire and develop reserves as a long-term hedge at current prices and at a lower utility-like ROE. The lower ROE will be acceptable to Black Hills' investors, provided that the risks are commensurate with a utility risk profile, as the COSG Program intends.

Q. EMBEDDED IN MR. SORENSEN'S CROSS-SUBSIDIZATION ARGUMENT IS THE CLAIM THAT THE COMPANY IS ESSENTIALLY ASKING THE COMMISSION TO NEUTRALIZE BLACK HILLS NON-REGULATED AFFILIATES' RISK IN THE GAS EXPLORATION AND PRODUCTION MARKET BY GUARANTEEING THOSE AFFILIATES EARN A PROFIT ON THEIR OPERATIONS WHETHER OR NOT THEY CAN DELIVER NATURAL GAS PROFITABLY.[59] HOW DO YOU RESPOND TO THIS CLAIM?

A. Mr. Sorenson misrepresents the COSG Program and is incorrect. The COSG Program is a program designed to provide a long-term physical hedge against natural gas prices for the Company's customers. The COSG Program would not include exploration risk. The

[59] Sorenson Direct Testimony, Page 13, Line 23 to Page 14, Line 3.

COSG Program will develop only proven reserves. The design of the COSG Program began more than two and one-half years ago, prior to the recent drop in oil and natural gas prices. It is BHUH's intention to use BHEP's oil and gas experience to assist COSGCO in acquiring reserves and producing natural gas. Furthermore, BHUH and other affiliates, such as Black Hills Service Company ("BHSC"), may provide additional administrative assistance. None of this, however, would result in subsidization of non-regulated affiliates for several reasons. First, BHEP will not be investing any capital in COSGCO, BHUH, or the Company. Second, in compliance with affiliate transaction rules – specifically, 291 Neb. Admin. Code, Ch. 9 § 001.01A and 005.07, prices for services provided to the Company, through the COSG Program, by any nonregulated affiliate will not exceed the prices charged to nonaffiliates.[60] Third, should COSGCO acquire reserves from BHEP, the Company will have to demonstrate that the acquisition cost of those reserves will be on market-based terms as required by the COSG Agreement. Finally, BHEP will not be the producer of natural gas in this program; COSGCO will be the producer, and BHEP may or may not be the operator. Moreover, all of these elements will be reviewable by the Commission under the COSG Program.

Q. MR. SORENSON CHARACTERIZES THE COSG PROGRAM AS A "MECHANISM TO SUBSIDIZE [THE COMPANY'S] NON-REGULATED AFFILIATES . . . WITH NEBRASKA RATEPAYER FUNDS COLLECTED THROUGH THE COSG PROGRAM."[61] WHAT STEPS HAS THE COMPANY TAKEN TO ENSURE THAT NO SUCH CROSS-SUBSIDIZATION CAN OCCUR?

[60] Any costs allocated to the COSG Program from a "shared resource" affiliate (i.e., Black Hills Service Company - legal, tax, etc. or BHUH - IT) would be subject to the Company's Cost Allocation Manuals.
[61] Sorenson Direct Testimony, Page 12, Lines 14-15.

A. Any reserves or interests acquired for the COSG Program will reside in COSGCO, whether purchased from a third party or BHEP. As such, they will be clearly delineated as part of the COSG Program. If the reserves are purchased from BHEP, and as required by the COSG Agreement, the purchase will have to be on reasonable commercial terms that the Commission will have an opportunity to review and approve. In addition, any services provided to COSGCO by BHEP or any other non-regulated affiliate of the Company will be charged at equal to or less than the price charged to nonaffiliates. Finally, as noted in my direct testimony,[62] the COSG Program has been structured to comply with the numerous and substantial ring-fencing requirements to which the Company is subject.

Q. IN HIS DISCUSSION OF CROSS-SUBSIDIZATION, MR. SORENSON ARGUES THAT APPLICATION OF 291 NEB. ADMIN. CODE, CH. 9 § 005.07 IS NECESSARY TO PREVENT CROSS-SUBSIDIZATION AND THAT THE COMMISSION SHOULD DENY THE WAIVER OF CODE PROVISION BY THE COMPANY'S APPLICATION.[63] HOW DO YOU RESPOND TO THIS ARGUMENT BY MR. SORENSON?

A. It must be emphasized that the Company's request for a waiver of 291 Neb. Admin. Code, Ch. 9 § 005.07 is *conditional*.[64] The Company's Application clearly states that the Company is requesting a waiver of conflicting rules only "to the extent necessary."[65] However, as I testified above, in compliance with 291 Neb. Admin. Code, Ch. 9 § 005.07, prices for services provided to the Company by any nonregulated affiliate will not exceed the prices charged to nonaffiliates and, as a result, a waiver should not be necessary. The

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[62] Vancas Direct Testimony, Pages 27-31.
[63] Sorenson Direct Testimony, Page 11; *Id.*, Page 14.
[64] Application, Preamble on Page 1.
[65] *Id.*

Company is merely making a *conditional* request for waiver out of an abundance of caution to ensure that all issues that conceivably could arise in this docket would be addressed by the COSG Application.

Q. DO YOU HAVE ANY CONCLUDING REBUTTAL TESTIMONY?

A. Yes. The COSG Program, as proposed, is carefully structured to balance the interests of shareholders, who would provide all the capital, and customers. The Company believes that this proposal will benefit customers by protecting 50% of their gas supply from the volatility of market prices and the likely increase in market prices over the long-term. To the extent that the Commission determines that the potential modifications described above would improve the COSG Program, the Company will not object to such modifications, because it wants customers to realize the benefits of the COSG Program. The current, but unsustainable, price environment presents an ideal opportunity to implement a COSG Program.

VI. CONCLUSION

Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes.