PUBLIC VERSION

Direct Testimony
Ivan Vancas

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Exhibits

I. INTRODUCTION AND QUALIFICATIONS

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. Ivan Vancas, 625 Ninth Street, P.O. Box 1400, Rapid City, South Dakota 57701.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am employed by Black Hills Corporation ("BHC") as Vice President, Operations Services. My areas of responsibility include directing asset optimization, which includes generation dispatch and power marketing, gas supply, and electric transmission, and I also direct electric and gas engineering, customer service, environmental and safety for BHC.

Q. FOR WHOM ARE YOU TESTIFYING?

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

Q. PLEASE DESCRIBE YOUR EDUCATIONAL AND BUSINESS BACKGROUND.

A. In 1989, I graduated from Kansas State University with a Bachelor of Science Degree in Electrical Engineering. I joined Black Hills/Colorado Gas Utility Company on July 14, 2008 as Vice President of Colorado and Kansas Gas Operations. On August 31, 2010, I became Vice President of Utility Services for BHC and continued in that role until I accepted my current position, which I have held since June 2012. Prior to working for Black Hills, I worked for Aquila, Inc. and its predecessor companies since 1989, and held various positions in field operations, engineering and management.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THIS COMMISSION?

A. No.

II. PURPOSE OF TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY?

A. My testimony introduces each of the witnesses who have provided testimony in support of the Company's application and briefly describes the topics of their respective testimony. In addition, I explain what the Company is requesting in its application, explain the manner in which the Company currently procures natural gas supply for the benefit of its customers, and describe the purpose and reasons for a long-term hedge program like the proposed Cost of Service Gas Program ("COSG Program"). My testimony also addresses how the COSG Program is designed to provide long-term price stability to customers with reasonably anticipated savings for customers over the life of the program. I describe how the COSG Program will operate, including its business structure, and the involvement of Black Hills Utility Holdings, Inc. ("BHUH") and COSGCO (the subsidiary of BHUH that would acquire the gas reserve interests) in the COSG Program. I also discuss the terms of the proposed Cost of Service Gas Agreement (the "COSG Agreement"), a copy of which is attached as Exhibit IV-1 to my testimony. Finally, I discuss certain ring-fencing protections and explain how the COSG Program is consistent with and will provide those protections to the Company's utility operations.

III. INTRODUCTION OF WITNESSES PROVIDING TESTIMONY SUPPORTING THE APPLICATION

Q. PLEASE IDENTIFY THE COMPANY'S OTHER WITNESSES AND PROVIDE A BRIEF DESCRIPTION OF THEIR TESTIMONY.

A. In addition to my testimony, the Company's application is supported by the testimony of the following individuals:

John Benton: Mr. Benton describes the gas exploration and production industry, including common structures for acquiring gas reserves and the types of production costs incurred in gas exploration and production. His testimony also discusses Black Hills Exploration and Production, Inc. ("BHEP"), its history and expertise in acquiring and developing shale and tight gas reserves, and its advisory and other potential roles in the COSG Program.

Richard ("Chuck") Loomis: Mr. Loomis explains the Company's current diversified portfolio approach to gas supply, and the reasons for its decision to seek approval to hedge up to 50% of the Company's natural gas demand under the COSG Program. Mr. Loomis also explains the long-term natural gas price forecast used by the Company and Aether Advisors, LLC (an expert retained by BHUH) in its assessment of the COSG Program.

Julia Ryan (Aether Advisors LLC): Ms. Ryan discusses Aether's review of the Company's gas portfolio strategy, the recommendations Aether has made regarding actions the Company should consider taking to include long-term hedging mechanisms, and explains how the COSG Program, as proposed, is consistent with that objective.

Aaron Carr: Mr. Carr describes the regulatory oversight of the COSG Program as well as the customer protections incorporated into the COSG Agreement and the COSG Program design, including (i) guidelines for future acquisitions and drilling plans, (ii) reviews of those acquisitions and drilling plans, (iii) the retention of independent accounting and hydrocarbon monitors, and (iv) other COSG Program protections for customers. Finally, Mr. Carr explains a hypothetical model used by the Company as a tool to evaluate the costs and benefits of the COSG Program as compared with the costs and benefits that would result from the continued purchase of gas at the prices in the long-term spot market.

Chris Kilpatrick: Mr. Kilpatrick's testimony addresses accounting and regulatory issues related to the COSG Program, including, how "Hedge Credits" and "Hedge Costs" are forecast and determined; how investment base, expenses, revenues, and return on equity are calculated; how forecast and actual costs will be accounted for, trued-up and adjusted as necessary; and how tariff sheets will be modified in light of the COSG Program.

Finally, Mr. Adrien McKenzie discusses the capital structure of the COSG Program and the basis for and reasonableness of the requested return on equity.

IV. SUMMARY OF THE COST PROGRAM AND THE COMPANY'S APPLICATION

Q. CAN YOU PROVIDE A BRIEF SUMMARY OF THE COSG PROGRAM?

A. The COSG Program is designed to be a long-term hedging program to reduce the Company's customers' exposure to the volatility of gas prices, to provide long-term price stability through a physical hedge, and to provide an opportunity for customers to pay less than market prices over the long term. Under the COSG Program, the physical hedge would be created through the acquisition, by COSGCO, of reserves that are producing or would be drilled to produce gas at production cost which, over the life of the wells and on a net present value basis, are anticipated to be below forecast market prices. In other words, the COSG Program would effectively peg a portion of customers' gas costs to today's low gas prices and to stable and predictable production costs during the term of the COSG Agreement.

Q. PLEASE EXPLAIN WHAT THE COMPANY IS REQUESTING IN ITS APPLICATION.

A. The Company is seeking a determination that the COSG Program, including the COSG Agreement, is prudent for the Company to pursue and that the amounts associated with the COSG Program are eligible for recovery through the GCA In this regard, the Company is requesting that the Commission:

1. Authorize the Company to enter into the COSG Agreement, which incorporates (a) acquisition and drilling criteria; (b) an expedited process for Commission review of acquisition opportunities; and (c) other guidelines to protect the Company's customers. Guidelines to protect customers include: (i) Commission review of all proposed drilling plans every five years; (ii) the retention by BHUH of a mutually-acceptable hydrocarbon monitor (the "Hydrocarbon Monitor") that would review potential acquisitions and drilling plans, and (iii) the retention by BHUH of a mutually-acceptable accounting monitor (the "Accounting Monitor") that would assess the financial information of the COSG Program as provided in the COSG Agreement and provide an assurance report;

2. Approve the revised tariff sheets that incorporate the "Hedge Credits" and "Hedge Costs" under the COSG Program;

3. Approve the requested 50% hedge-participation level based on the Company's forecast annual firm demand or, in the alternative, a revised percentage that the Commission may determine; and

4. To the extent necessary, grant any waivers from affiliate rules or regulations or ring-fencing commitments, the Commission deems necessary.

Q. WHY DOES THE COMPANY NEED A PRUDENCE DETERMINATION WITH RESPECT TO THE COSG PROGRAM?

A. First, a prudence determination is required by Neb. Rev. Stat. § 66-1854. Second, as explained in more detail below, the Company believes a prudence determination is advisable in light of ring-fencing protections that were put in place when BHUH acquired certain of the utilities that could be involved in the COSG Program. Third, while the Company already purchases gas from market sources through or with the assistance of BHUH to meet its customers' needs, the COSG Program is the first time the Company would be participating in a program under which long-term gas reserve interests are acquired. Because of the significant investment and extended commitments involved and because the COSG Program will require coordination with utilities in several states, the Company believes it is appropriate to seek a prudence determination from this Commission, as well as the public utility commissions in each state where the COSG Program would operate, before undertaking the COSG Program. Finally, the nature of gas reserve acquisitions necessitates both pre-approval of the Commission oversight process and the acquisition guidelines that are incorporated into the COSG Agreement. The desired closing timelines of typical sellers of oil and gas interests are shorter than typical Commission review processes, and the COSG Program will likely find willing sellers who will want some comfort that the Commission will likely approve a proposed transaction. The proposed Commission oversight process and guidelines address these issues, while also appropriately protecting the Company's customers.

V. GENERAL DESCRIPTION OF BHUH AND THE COMPANY'S CURRENT GAS PROCUREMENT STRATEGY

Q. WHAT IS BHUH AND HOW IS IT RELATED TO THE COMPANY'S APPLICATION?

A. BHUH is a wholly owned subsidiary of BHC. BHUH was organized in July 2008 when BHC purchased certain gas and electric utility operating companies from Aquila, Inc. BHUH is the parent corporation of those operating companies, which include (as renamed):

- Black Hills/Colorado Electric Utility Company, LP;
- Black Hills/Colorado Gas Utility Company, LP;
- Black Hills/Iowa Gas Utility Company, LLC;
- Black Hills/Kansas Gas Utility Company, LLC; and
- Black Hills/Nebraska Gas Utility Company, LLC

(collectively, "the BHUH Utilities"). BHUH also provides services and support to three additional affiliated BHC utility companies:

- Black Hills Power, Inc.;
- Cheyenne Light, Fuel and Power Company; and
- Black Hills Northwest Wyoming Gas Utility Company, LLC

(collectively, "the "Affiliated Utilities"). For the sake of simplicity, I will refer to the BHUH Utilities and the Affiliated Utilities simply as "the Utilities." Under the COSG Program, BHUH would be a party to the COSG Agreement and would be responsible for overseeing COSGCO (which would be a wholly owned, direct subsidiary of BHUH that would acquire the gas reserves), administering the COSG Program, and ensuring that costs and credits are properly allocated to each utility participating in the COSG Program. The responsibility of COSGCO is described later in my testimony.

Q. DOES BHUH CURRENTLY PLAY ANY ROLE IN THE UTILITIES' GAS PURCHASES AND, IF SO, WHAT ROLE DOES IT PLAY?

A. BHUH currently enters into gas supply and transportation contracts in BHUH's name to obtain the gas supply necessary to meet the BHUH Utilities' gas needs. After purchasing gas for the BHUH Utilities, BHUH uses contracted pipeline capacity to transport the gas to each utility at specified locations along the pipeline. The costs involved in this process are allocated to each BHC utility according to that utility's designated share of the costs. The process is slightly different for the Affiliated Utilities. The Affiliated Utilities each have their own gas supply and transportation contracts that are managed by BHUH as agent. After gas purchases are made by the Affiliated Utilities, that gas is transported over each Affiliated Utility's interstate pipeline capacity to the utility. Any costs BHUH incurs in acting as agent for the Affiliated Utilities are either directly charged or allocated to each Affiliated Utility according to its share of those costs.

Q. WHAT KINDS OF ARRANGEMENTS DOES THE COMPANY CURRENTLY USE TO MEET ITS NATURAL GAS NEEDS?

A. As explained in more detail in the testimony of Chuck Loomis, the Company acquires natural gas, through or with the assistance of BHUH, from producers and marketers under various arrangements, including spot market purchases, short-term fixed price contracts and storage purchases, and short-term and medium-term financial hedges.[1] The

[1] Short-term hedging refers to hedging for the current year and the upcoming gas year (i.e. 1-2 years). Medium-term Hedging refers to hedging for gas years 3-7. The only medium-term hedging engaged in by BHUH relates to certain hedging for its Colorado electric utility.

general percentages of the Company's annual gas supply purchased through each of these methods are identified on Exhibit IV-2 to my testimony.

Q. WHY DOESN'T THE COMPANY SECURE LONG-TERM FIXED PRICE CONTRACTS OR HEDGES TO AVOID MARKET PRICE INCREASES?

A. Producers are typically not inclined to enter into long-term fixed price contracts as contemplated in the COSG Program due primarily to limitations on upside return, *i.e.* if prices rise in the future they are unable to receive the benefit of those increases. John Benton discusses this and other reasons why producers are not inclined to enter into such contracts.

While long-term financial hedges may be available on a limited basis, they command a forward price premium, and would subject the Company to assuming significant collateral posting requirements and counterparty credit risk.

Q. HAS THE COMPANY EXPLORED OPTIONS FOR LONG-TERM FIXED PRICE NATURAL GAS CONTRACTS? IF SO, WHAT WERE THE RESULTS?

A. Yes. As explained in more detail in the testimony of Chuck Loomis, the Company, through BHUH, has investigated the availability and cost of long-term fixed price natural gas contracts and hedges. [redacted] The reasonably anticipated price for the proposed COSG Program would be lower than this figure.

Q. AREN'T THE CURRENT SPOT MARKET PRICES AT ONE OF THE HISTORIC LOWS? IF SO, WHY SHOULD THE COMPANY TAKE ANY ACTION NOW TO IMPLEMENT A LONG-TERM HEDGING STRATEGY?

While it is true that spot market prices are at one of the historic low points compared to recent history, current prices are insufficient to generate the funds necessary to drill new wells except in the most efficient locations, even in shale gas or tight gas formations. History has also shown that prices are volatile and will likely rise, and could even rise rapidly to levels that are substantially higher than the current prices. In her testimony, Julia Ryan discusses historical and forecast gas prices, noting that, because gas prices are at one of the low points compared to recent history, and are at or near the break-even price, prices in the future are more likely to rise than fall.

In addition, it is worth noting that, short- and mid-term fixed price contracts and financial hedges are not, by themselves, sufficient to blunt the impact of the price increases, because these contracts and hedges tend to track the current market price. As the market price of gas rises, the cost of short- to medium-term fixed-price contracts and financial hedges will similarly rise. By contrast, if natural gas prices increase, the value of the Hedge Credits the customers would receive under the COSG Program (one of the benefits of the program) would increase. Thus, the higher the market price, the greater the benefit of the COSG Program. The COSG Program is anticipated to provide a lower-cost alternative to these more expensive market options, with greater price stability over the life of the COSG Program.

Q. CAN YOU MORE SPECIFICALLY EXPLAIN THE BENEFIT TO PURSUING THE COSG PROGRAM NOW IN LIGHT OF THE LOW NATURAL GAS SPOT MARKET PRICE?

A. Yes. The cost of acquiring reserves correlates to the market price of natural gas. This is the real advantage of implementing the COSG Program now, because natural gas reserves can be acquired and produced at a more favorable price over a long term as compared to a period when natural gas market prices may be higher. Moreover the reserves would be acquired in a low interest rate environment which may make financing a transaction now far more attractive than in subsequent years. In addition, because of the low market prices and the current excess gas capacity, which has caused a slow-down in drilling and production, COSGCO may be able to obtain favorable production and drilling service contracts for longer-term periods with contractors in need of steady work. Finally, as described more fully in the Aether report, gas prices are likely to rise in the future due to increased domestic demand, LNG exports and the EPA Clean Power Plan, among other influences.

Q. WHAT IS THE BENEFIT OF OWNING RESERVES RATHER THAN RELYING ON FINANCIAL OR PHYSICAL HEDGES?

A. There are a number of benefits to owning reserves compared to other forms of hedging. Specifically,

1. Available financial hedges and fixed price gas contracts are for limited terms and cannot protect customers against longer-term increases in the price of natural gas.
2. The price of gas under the COSG Program can be reasonably anticipated to be lower, on a net present value ("NPV") basis, than the price under a series of short-term hedges that, over time, will follow spot market prices.
3. The buyer, in this case COSGCO, a subsidiary of BHUH, holds title to a physical asset, as opposed to a contractual promise from a counterparty that is at risk of default. Ownership of reserves constitutes the highest security of supply/production.

4. If natural gas prices increase significantly, the value of the "Hedge Credit" to customers under the COSG Program increases.

Q. HAVE OTHER UTILITIES IMPLEMENTED LONG-TERM PHYSICAL HEDGE PROGRAMS?

A. Yes. A number of utilities or utility affiliates have implemented or are currently seeking to implement long-term physical hedge programs. A few examples demonstrate how such programs are being structured. For example, the Utah and Wyoming public utility commissions approved a long-term physical hedge program for Questar Gas in 1981.[2] Under that program, Wexpro, an exploration and production company affiliate of Questar Gas, drills wells to produce gas for the benefit of Questar Gas' customers. An additional program was approved in 2013 known as Wexpro II, allowing Wexpro to acquire and develop additional properties.[3] The utility commissions in Utah and Wyoming have approved an acquisition under that new program. In addition, in 2011, the Oregon Public Utility Commission approved Northwest Natural Gas Company's ("NW Natural") $250 million joint development agreement with Encana Oil and Gas (USA) Inc.[4] NW Natural acquired reserves in a Wyoming gas field by paying a portion of the costs to drill new wells. Upon the termination of this joint drilling program, Northwest Natural Gas has the opportunity to develop additional gas reserves on the subject property under a joint operating agreement. Similarly, in 2014, Florida Power & Light sought and obtained

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[2] *In re the Investigation of the Transfer of Certain Wells, Leases, Lands and Related Buildings and Interests of Mountain Fuel Supply Company and/or Wexpro Company to Celsius Energy Company or Any Other Entity or Person*, Dkt. No. 81-057-04, Report and Order on Stipulation and Agreement (December 31, 1981).
[3] *In the Matter of the Application of Questar Gas Company for Approval to Include Property Under the Wexpro II Agreement*, Dkt. No. 13-057-13, Report and Order (Jan. 17, 2014).
[4] *In the Matter of Northwest Natural Gas Company's Applications for Deferred Accounting Order Regarding Purchase of Natural Gas Reserves and Proposed Purchase of Natural Gas Reserves*, Docket Nos. UM1520 & UG 204, Order (April 28, 2011).

approval from the Florida Public Service Commission to invest $191 million in a joint venture with PetroQuest Energy, Inc. to develop and operate new natural gas production wells in the Woodford Shale Gas region in Oklahoma.[5] Unlike Northwest Natural Gas, Florida Power & Light does not have the right to participate in additional drilling on the properties subject to their agreement with PetroQuest. However, in 2015, the Florida Public Service Commission approved guidelines under which Florida Power & Light can invest up to $500 million annually in additional gas reserves.[6] To secure a long-term supply of natural gas at relatively fixed prices, Washington Gas, a Virginia utility, recently entered into a $126 million purchase and sale agreement with Energy Corporation of America ("ECA") to acquire 22 producing natural gas wells in Pennsylvania for 20 years.[7] Finally, in 2012, the Montana Public Service Commission approved NorthWestern Energy's ("NorthWestern") request to include natural gas production properties in rate base and to allow for recovery of expenses associated with the acquisition of the natural gas production properties.[8] In 2013, NorthWestern spent $70.2 million to acquire Devon Energy Production Company's interest in approximately 900 natural gas wells in Montana's Bear Paw Basin.[9]

Q. ARE THERE RISKS IN INVESTING IN RESERVES?

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[5] *In re Fuel Cost Recovery*, Dkt. No. 150001-E1, Order No. PSC-15-0038-FOF-EI 7 (FPSC Jan. 12, 2015).
[6] *In Re Fuel and Purchase Power Cost Recovery Clause With Generating Performance Incentive Factor (In Re Fuel Cost Recovery)*, Dkt. No. 150001-E1, Doc. No. 03723-15 (FPSC June 18, 2015).
[7] *In re Wash. Gas Light Co.*, Dkt. No. PUE-2015-00055, Doc. No. 150520224 (VSCC May 12, 2015).
[8] *In re NorthWestern Energy's Application to Place the Battle Creek Natural Gas Production Resources in Rate Base and Recover Associated Expenses (In re NorthWestern)*, Dkt. No. D2012.3.25, Order No. 7210b at 17-18, 21 (MPSC Nov. 16, 2012).
[9] *NorthWestern Energy Completes Purchase of Natural Gas Assets in Montana*, PR Newswire (Dec. 2, 2013), *available at* http://www.prnewswire.com/news-releases/northwestern-energy-completes-purchase-of-natural-gas-assets-in-montana-234142471.html.

A. Yes. John Benton's testimony describes several risks, including (i) the risk that the volume of gas actually produced is less than the volume of estimated reserves, and (ii) the risk that the actual costs to develop reserves is greater than expected. However, the acquisition guidelines incorporated into the COSG Agreement focus investment in gas reserves that are "proven," which means they have the greatest probability of being recovered (e.g., 90% or more for proved developed producing reserves) and that have predictable and consistent costs per well. In addition, there are environmental risks with investing in reserves, predominantly dealing with compliance with current and evolving rules and regulations. Since BHEP has extensive exploration and production experience, BHEP is qualified to assist COSGCO in evaluating and mitigating these risks.

VI. THE COSG PROGRAM

Q. PLEASE DESCRIBE IN MORE DETAIL THE COSG PROGRAM.

A. To minimize customers' exposure to the volatility of gas market prices, to provide long-term price stability through a physical hedge, and to provide an opportunity for customers to pay less than market prices over the long term, the Company, along with other BHC utility companies in several states, proposes to enter into the COSG Agreement with BHUH. Specifically, as proposed, the COSG Program is being submitted for Commission or Board approval in the following states: Colorado, Iowa, Kansas, Nebraska, South Dakota, and Wyoming.

Under the COSG Program, BHUH, through COSGCO, would acquire gas reserves, using non-Company funds. As required by the acquisition criteria in the COSG Agreement, the acquired reserves would consist of fields with proven reserves and an operating history, demonstrating drilling and operating costs. In addition, the acquired reserves would be located in fields with established gathering and processing capabilities and connections to interstate pipelines, or in fields for which production and transportation costs can be reliably estimated to minimize risk. The estimated cost of acquiring, developing, and producing the reserves would be, on a net present value basis, at a cost anticipated to be less than the long-term market price gas forecast, such that the acquisition and development would be reasonably anticipated to save the Company's customers money over the life of the COSG Program.

COSGCO would produce natural gas and associated liquids. However, unless agreed otherwise, the Company would not directly receive the gas produced from the wells. Rather, for tax and other reasons explained below, the gas produced would be sold to third parties, and BHUH would purchase or act as agent in purchasing, from the market, gas needed by the Company just as it does today. Under the COSG Program, when the effective cost of gas is less than the market price of gas, customers will receive the benefit of a "Hedge Credit" that would offset or reduce the gas price paid by customers. By contrast, when the effective cost of gas is more than the market price of gas, the Company would be charged a "Hedge Cost" to make up for the difference.

To provide oversight of the COSG Program, BHUH would retain, subject to Commission approval, a Hydrocarbon Monitor. The Hydrocarbon Monitor would be an independent third party not affiliated in any way with the Company or BHUH and would (i) assess any proposed acquisition or an initial drilling plan and provide a written recommendation regarding whether the proposed acquisition or drilling plan satisfies the criteria in the COSG Agreement; and (ii) assess every five years the future drilling plans and provide a written recommendation regarding whether the those plans satisfy the drilling criterion in the COSG Agreement. In addition, BHUH would retain, again subject to Commission approval, an Accounting Monitor. The Accounting Monitor, also an independent third party not affiliated with the Company or BHUH, would conduct annual assessments of BHUH's calculations under the COSG Program as provided by the COSG Agreement and provide an assurance report of its findings for the Commission. Aaron Carr discusses the Monitors in more detail in his direct testimony.

Q. HAVE YOU PREPARED A SUMMARY OF THE FINANCIAL AND OPERATIONAL TERMS OF THE COSG PROGRAM?

A. Yes. Attached as Exhibit IV-3 to my testimony is a summary of the principal financial and operational terms of the COSG Program.

Q. HOW WOULD COSGCO ACQUIRE AND DEVELOP THE RESERVES?

A. As addressed in John Benton's direct testimony, acquisitions would be structured either as direct purchases of gas reserves (like Washington Gas) or under a joint development arrangement (similar to what Northwest Natural Gas and Florida Power and Light did), or a combination of both. Attached as Exhibit IV-4 are diagrams showing two possible structures for how the COSG Program would work depending upon the kind of acquisition available.

Under Alternative A, COSGCO would purchase gas reserves from a third party. BHEP or another third party would operate existing wells and drill new wells on the property and produce the gas for COSGCO.

Under Alternative B, COSGCO would earn an interest in the reserves by funding a portion of the drilling and operating costs for a third party. BHEP or another third party would operate existing wells and drill new wells on the property and produce the gas, again on COSGCO's behalf. If BHEP is not the operator of the wells, it would still be involved as COSGCO's expert to monitor the performance of the third party and protect COSGCO's interests.

Q. HOW MUCH OF THE COMPANY'S GAS WOULD BE HEDGED BY THE COSG PROGRAM?

A. As explained in the testimony of Chuck Loomis and based on the report and recommendation of Aether Advisors, LLC, the COSG Program would physically hedge up to 50% of the Company's forecasted annual firm gas demand each year.

Q. IS THERE A RISK TO CUSTOMERS FROM DELAYING ACQUISITION OF A HIGHER LEVEL OF RESERVES AND IMPLEMENTING THE COSG PROGRAM AS A SIGNIFICANT COMPONENT OF THE PORTFOLIO?

A. Yes. Importantly, assigning 50% of the portfolio to cost of service gas and including numerous customer protections is a superior approach than establishing a lower initial target percentage of the portfolio, and then trying to increase it later. Under the COSG Program, as market prices rise, customer benefits (savings relative to market prices) increase when a higher percentage of the portfolio is stable-priced cost of service gas. Additionally, as market prices rise, the cost of acquiring incremental reserves increases and competition for drilling rigs and drilling services increases, leading to higher costs and an increased risk that resources and service providers will not be available. In other words, by waiting, the Company could essentially be chasing the market, which would undermine the desired long-term price stability provided by long-term hedging through the COSG Program. This is demonstrated by figure 73 of the Aether Report (Exhibit JMR-1 to the direct testimony of Julia Ryan), which shows that, while there is an element of opportunity cost that exists in low price scenarios, enhanced price stability and greater opportunities for cost savings are achieved with a higher percentage of the portfolio being comprised of production from owned reserves. Essentially, Aether's research demonstrates that there is more upside opportunity to provide benefits to customers and relatively little additional downside risk by acquiring reserves now and implementing a cost of service gas program to provide 50% of the portfolio.

Q. WHY UNDER THE COSG PROGRAM WOULDN'T COSGCO SIMPLY SELL ITS GAS TO THE COMPANY?

A. By selling its gas to third parties in the market rather than directly to customers, COSGCO would maximize the tax benefits available for the Company's customers. In addition, depending upon where the acquired reserves are located, delivering the produced gas directly to the utilities participating in the COSG Program may be cost-prohibitive due to transportation and other costs.

Q. WHY IS AN EXPEDITED REVIEW OF ACQUISITIONS AND DRILLING PROGRAMS NECESSARY?

A. As explained in more detail in John Benton's Direct Testimony, participants in the oil and gas industry will not wait 6-12 months for regulatory approval from multiple states as a condition to closing a transaction or entering into service contracts. For example, sellers of oil and gas interests will most often be interested in taking sales proceeds and quickly redeploying them elsewhere. As such, the standard regulatory approval process is in most cases, too lengthy to facilitate taking advantage of oil and gas opportunities. As such, without an expedited approval process, COSGCO would miss opportunities to make the strategic acquisitions or arrangements that may optimize the COSG Program and benefits for the Company's customers.

Q. HOW WOULD CUSTOMERS REALIZE THE ANTICIPATED BENEFITS OF THE COSG PROGRAM?

A. As explained in more detail in the direct testimony of Chris Kilpatrick, COSGCO would sell its gas (and other associated hydrocarbon products) with its return on equity calculated based on its capital investment, operating expenses, and revenue. As proposed, if COSGCO's actual return on equity from the sale of gas and liquids is more than the allowed return on equity under the COSG Program by more than 100 basis points in any given month, the Company would receive a Hedge Credit from BHUH against the amount owing for gas purchases during that month. This credit would then flow through to the Company's customers through the GCA. On the other hand, if COSGCO's actual return on equity is less than the allowed return on equity by more than 100 basis points, a Hedge Cost would be added by BHUH to the amount owed by the Company for the gas purchases in that month. As explained in the direct testimony of Adrien McKenzie and Chris Kilpatrick, the allowed return on equity would be the average of the annual return on equity for all gas and electric utility rate cases for the calendar year, as reported by Regulatory Research Associates, provided that, if there are less than twenty (20) gas and electric utility rate cases reported for a calendar year, the Allowed ROE will be the average of (i) the average of the annual return on equity for the gas and electric utility rate cases for that calendar year, and (ii) the average of the annual return on equity for all gas and electric utility rate cases for the prior calendar year, as reported by Regulatory Research Associates. These Hedge Credits and Hedge Costs are how customers would effectively receive a portion of their gas at a cost of service price.

Q. WHAT IS THE REASON FOR THE 100 BASIS POINT BAND ABOVE OR BELOW THE ALLOWED ROE?

A. Simply put, if customers save money (Hedge Credit) as a result of the COSG Program, the Company proposes to receive a portion of those savings up to an amount equal to 100 basis points above its allowed return on equity. If, on the other hand, customers pay an effective cost of service gas price that is above the market price (Hedge Cost), BHUH is penalized for the first 100 basis points. This arrangement incents BHUH to maximize the performance of the COSG Program.

Q. HOW WOULD THE COST OF CAPITAL BE CALCULATED?

A. As referenced in Chris Kilpatrick's direct testimony, the calculation of cost of capital used to acquire the reserves and to drill new wells would be based on 40% debt, 60% equity structure. The cost of debt will be the weighted average of the following: (i) the cost of long-term debt, if any, of COSGCO, and (ii) for the balance of forty percent (40%) of Investment Base, the weighted average of BHC's cost of long-term debt.

Q. WHY IS THE COMPANY MAKING THIS FILING PRIOR TO AN IDENTIFIED DRILLING PROPERTY BEING ACQUIRED?

A. First, the COSG Program will require significant investment by COSGCO and a long-term commitment by the Company. Second, the COSG Program will involve several BHC utilities. Finally, the COSG Program incorporates proposed reserve acquisition criteria, which have not yet been approved by this or any other Commission. While BHUH has made efforts to investigate the market and determine what options are available to acquire reserves, it is not prudent for BHUH to establish COSGCO and to invest the time, due diligence, and resources necessary to acquire gas reserves without knowing whether the COSG Program, including the related criteria and guidelines, will be approved by the Commission. COSGCO cannot justify undertaking such a sizable financial commitment without assurance that the Commission concurs. This uncertainty could also make it more difficult to negotiate deals with sellers, because they will be concerned both about the potential duration of Commission-review and the lack of clarity about the standards against which a potential deal would be considered by the Commission.

Q. WHEN DO YOU EXPECT AN ACQUISITION TO BE BROUGHT TO THE COMMISSION FOR REVIEW?

A. The Company plans to bring a potential acquisition forward for review by the Commission as soon as this application and the applications of other utilities that are proposed to participate in the COSG Program are approved and a property is identified. BHEP is currently evaluating potential acquisitions.

Q. IF THE COMMISSION APPROVES THIS APPLICATION AND THE VOLUME OF GAS TO BE HEDGED, IS THAT ALL THE APPROVAL THE COMPANY REQUIRES TO FULLY IMPLEMENT THE COSG PROGRAM?

A. No. As stated above, the Company needs to identify reserve interests that meet the criteria incorporated into the COSG Agreement and discussed in Aaron Carr's testimony (e.g., at a price that would likely result in NPV savings over the life of the asset). In addition, the Company would then need to submit the proposed acquisition to the Commission under the expedited review process for approval.

Q, IF A RESERVE INTEREST IS IDENTIFIED AND A DEAL NEGOTIATED, UNDER WHAT TIME FRAME DOES THE COMPANY EXPECT AN EXPEDITED REVIEW?

A. Sellers generally cannot wait more than a month or two to consummate a transaction as market prices fluctuate. The Company requests that an expedited review of a potential acquisition be completed within 60 days from the date of filing. In support of the expedited review, the Company would provide the Commission with a report from the independent Hydrocarbon Monitor advising whether the proposed acquisition satisfies the acquisition criteria approved by the Commission in this proceeding.

Q. IS THE COMPANY'S PARTICIPATION IN THE COSG PROGRAM CONTINGENT ON RECEIVING COMMISSION APPROVAL?

A. Yes. The Company will not participate in the COSG Program if approval is not granted by the Commission.

Q. **WILL THE COMPANY PURSUE COSG IF THE COMMISSION DETERMINES THE COSG PROGRAM IS PRUDENT BUT ORDERS PARTICIPATION AT A LEVEL OF VOLUMES HEDGED THAT IS LESS THAN THE COMPANY RECOMMENDS?**

A. The Company may or may not pursue the COSG Program depending on the levels of volumes the Commission orders to be hedged. There has to be a level of scale to the COSG Program to minimize administrative and other costs and to facilitate a reasonable COSG price to customers that would make the COSG Program viable.

Q. IF THE COMMISSION DOES NOT APPROVE THE COMPANY'S PARTICIPATION IN THE COSG PROGRAM NOW, WILL THERE BE AN

OPPORTUNITY TO PARTICIPATE IN THE FUTURE OR INCREASE PARTICIPATION LATER?

A. Possibly. As the COSG Program is designed, only those utilities participating in an acquisition and the drilling programs for a reserve interest will be able to receive the benefits derived from that interest. If the participating utilities believe it is prudent for them to allow other utilities to participate in the COSG Program, a utility that does not participate in the COSG Agreement at inception may be permitted by the parties to become a party to the COSG Agreement and participate in subsequent acquisitions and drilling programs. However, it is also possible that an initial acquisition will meet the hedge needs of the participating utilities, and there may not be any future opportunities for a non-participating utility to join into the COSG Program. Moreover, the terms and conditions of future participation may vary significantly.

Q. IS THE COSG PROGRAM CAPABLE OF BEING MODIFIED ON A STATE-BY-STATE BASIS?

A. With other than minimal exceptions, no. As proposed, the COSG Program is a multi-state program that would involve utilities in Colorado, Iowa, Kansas, Nebraska, Wyoming and South Dakota. Because the utilities that participate in the COSG Program from these states would be parties to the same COSG Agreement and the same program, the terms of that arrangement cannot be modified or varied on a state-by-state basis without impacting other utilities and the processes in other states. Where minor variations, such as the percentage of the Company’s annual forecast demand that will be hedged, can be made without impacting the rights and obligations of other participants or adding excessive administrative costs to the COSG Program, modifications may be approved to accommodate such variations.

VII. <u>THE COSG AGREEMENT</u>

Q. WHAT IS THE COSG AGREEMENT AND WHY IS IT NECESSARY?

A. The COSG Agreement is the governing document between BHUH and the utilities participating in the COSG Program. It sets forth the parties' respective rights and obligations. The COSG Agreement is necessary for several reasons. First, as proposed, the COSG Program would involve BHUH, COSGCO, and multiple utilities across several states, including the Company. The COSG Agreement defines how the COSG Program will operate between these parties and provides their respective rights and obligations. Second, the COSG Agreement explains how Hedge Credits and Hedge Costs will be calculated and allocated, and provides a means of enforcing the parties' rights and obligations. Third, because the Company believes that independent oversight of the COSG Program is appropriate, the COSG Agreement establishes what is expected of the Hydrocarbon and Accounting Monitors and explains their reporting requirements. Fourth, the COSG Agreement sets out the acquisition and drilling criteria and the other guidelines for the COSG Program, and establishes the procedure for Commission review of acquisitions and drilling programs.

Q. WHO WOULD BE THE PARTIES TO THE COSG AGREEMENT?

A. The parties to the COSG Agreement would be BHUH and each of the utilities that participate in the COSG Program.

Q. WHERE ARE THE ACQUISITION CRITERIA AND FIVE-YEAR DRILLING CRITERION IN THE COSG AGREEMENT?

A. The acquisition criteria are set forth in Exhibit A of the COSG Agreement. The five-year drilling plan criterion is set forth in Exhibit B of the COSG Agreement. These criteria are discussed in more detail in Aaron Carr's direct testimony.

Q. WHAT IS THE TERM OF THE COSG AGREEMENT?

A. As set forth in Section 6.1 of the COSG Agreement, the term of the COSG Agreement would commence upon the effective date of the COSG Agreement and would run until the wells on the acquired properties have been plugged and abandoned, and the properties reclaimed. As explained in the testimony of John Benton, the typical life of a tight gas well is at least 20 years.

Q. IF THE COMMISSION WANTED THE COMPANY TO TERMINATE ITS PARTICIPATION IN THE COSG AGREEMENT, CAN IT DO SO AND, IF SO, WHEN CAN IT DO SO?

A. Section 6.2 of the COSG Agreement provides that if a utility is ordered by its public utility commission or board to terminate its rights and obligations under the COSG Agreement before the end of the term of the agreement, the terminating utility will give notice of that direction to BHUH. After receiving the termination notice, and to facilitate the termination and disposition of the terminating utility's interest in the COSG Program, BHUH will cause COSGCO to sell an interest in the Properties (excluding any Property in which the terminating utility did not participate) that is functionally equivalent to the terminating utility's then-current percentage share of the COSG Program. Before the sale can occur, however, the remaining utilities must approve the interest to be sold and the terminating utility must approve the sale price. Following the sale, the Investment Base, as set forth in the COSG Agreement, will be adjusted to reflect the sale. The termination will be effective at the end of the calendar month in which the sale closes so long as any other amounts due under the COSG Agreement are paid. Pursuant to Section 6.4 of the COSG Agreement, if the sale proceeds are greater than the terminating utility's share of Investment Base, then COSGCO will retain from the sale proceeds an amount equal to the terminating utility's share and the excess proceeds will be passed on to the terminating utilities' customers. In contrast, if the proceeds are less than the terminating utility's share of Investment Base, then COSGCO will retain the proceeds from the sale and the terminating utility will also pay BHUH an amount equal to the shortfall, which such amount being incorporated into the terminating utility's GCA as a cost of gas.

Q. CAN THE COMMISSION ORDER THE COMPANY TO LOWER ITS LEVEL OF PARTICIPATION IN THE COSG PROGRAM AT A FUTURE DATE?

A. Yes. Section 4.4 of the COSG Agreement provides that the Commission can decide that the Company will not participate in any five-year drilling plan. As explained in John Benton's testimony, wells from shale or tight gas resources have a decline curve that requires drilling of additional wells each year to maintain a level volume of production from a particular property.

Q. ARE THE UTILITIES THAT BHC IS ACQUIRING FROM SOURCE GAS PARTICIPATING IN THE COSG PROGRAM?

A. No. Black Hills Corporation's acquisition of Source Gas's utilities has not been completed. Should a Source Gas utility being acquired desire to participate in the COSG Program at a future date, it would need to file an application with the Commission at that time.

VIII. COMPLIANCE WITH RING-FENCING PROTECTIONS

Q. PLEASE IDENTIFY ANY PERTINENT[10] RING-FENCING PROTECTIONS AND EXPLAIN HOW THE COSG PROGRAM COMPLIES WITH THOSE PROTECTIONS.

A. When BHC acquired the gas and electric utilities of Aquila in 2008, which were located in Colorado, Iowa, Kansas and Nebraska, BHC, BHUH and the utilities being acquired committed to comply with certain ring-fencing protections. Additionally, in the acquisition of the Energy West system and MGTC system in Wyoming in the past year, similar ring-fencing protections were also committed to. While each state worded the protections in slightly different ways, those protections can be organized into various categories. Below is a summary of the protections in each category, as well as an explanation of how the COSG Program complies with each protection:

Accounting Protections

- *All shared administrative expenses shall be properly allocated to each BHUH Utility subsidiary*: Under the COSG Program, all administrative expenses are part of the calculation of Hedge Credits and Hedge Costs, which will be allocated to the respective utilities participating in the program according to each utility's percentage participation in the program. As such, each utility will only bear its share of administrative costs

[10] While there are other ring-fencing or ring-fencing-like protections, they relate to matters that are not related to the concepts proposed in the COSG Program.

- *Separate money pools must be maintained for utility and non-utility entities under BHC's then-current structure and agreements*: The COSG Program does not alter BHC's existing structures and agreements or money pools.
- *Separate books, records, systems of accounts, financial statements and bank accounts shall be maintained for each utility, except where utility funds are pooled*: Each BHUH utility maintains its own books, records, system of accounts, financial statements and bank accounts. The COSG Program will not change this in any way.

Organizational Protections

- *Non-utility operations of BHC entities must remain in subsidiaries that are separate and independent from the operations of the BHUH Utilities or their subsidiaries*: Under the COSG Program, COSGCO will be established as an entity that, while under BHUH, will be separate and independent from the BHUH utilities and their subsidiaries. All other non-utility operations will also remain separate and independent from the BHUH utilities.
- *BHUH and its utilities will hold their assets in their own names and maintain adequate capital for their business purposes*: BHUH and the utilities participating in the COSG Program will hold their own contractual rights under the COSG Agreement.

Credit and Financing Protections

- *BHUH and its utility subsidiaries will not provide or extend credit to, issue long-term debt, or pledge utility assets to support BHC or any of its non-utility subsidiaries or affiliates*: Under the COSG Program, the BHUH Utilities will not provide or extend credit to, issue long-term debt to, or pledge any assets to support BHC or any non-utility subsidiary or affiliate. In fact, the COSG Agreement contains a specific covenant preventing any utility from pledging assets as part of the program. *See* COSG Agreement, Section 7.1.

- *BHUH and its utility subsidiaries will not guarantee any new debt obligations, notes, debentures, or any other security of BHC or its non-utility operations, nor will BHUH or its utility subsidiaries' assets be used as collateral for BHC's non-utility operations*: The COSG Agreement specifically prohibits BHUH and its utility subsidiaries from guaranteeing any new debt obligations, notes, debentures, or any other security of BHC or its non-utility operations. In addition, the COSG Agreement prohibits BHUH or utility assets from being used as collateral. *See* COSG Agreement, Section 7.2.
- *New stand-alone or project financing for non-utility business activities (asset acquisitions, project development, credit arrangements) will be without recourse to BHUH or its utilities*: Under the COSG Agreement, any new stand-alone project financing for non-utility business activities is required to be without recourse to BHUH or its utilities. *See* COSG Agreement, Section 7.3. Further, as noted above, every acquisition under the COSG Program will be presented to the Commission for review and approval.
- *Non-utility subsidiaries will not lend money directly to BHUH or its utility subsidiaries, and non-utility subsidiaries will not carry inter-company accounts payable balances with any BHUH Utility that is above the normal level of business transactions*: Under the COSG Program, neither COSGCO nor BHEP

would lend money to BHUH or the BHUH Utilities. Moreover, no non-utility subsidiaries will carry inter-company accounts payable balances with any BHUH Utility. BHUH will calculate all Hedge Credits and Hedge Costs, not COSGCO.

<u>Fairness and Reasonableness of Transactions</u>

- *Any services BHUH and its utilities provide to any non-utility subsidiaries or affiliates would be charged at tariff rates, if applicable, or at the actual cost or market rate, whichever is higher*: Under the COSG Program, BHUH Utilities will not provide any utility-type services to COSGCO except at tariff rates. In addition, all other services BHUH will provide under the COSG Program will be charged on a cost basis. Any services provided by BHUH to COSGCO will be, in effect, services that would benefit the utilities.
- *Any services provided to BHUH or its utilities by non-utility subsidiaries or affiliates of BHC shall be reasonably necessary and appropriate for the utility business and would be charged at rates not higher than market rates*: COSGCO will not provide services to BHUH or the BHUH Utilities under the COSG Program. Rather, Hedge Credits and Hedge Costs will be calculated by BHUH based on market gas prices and COSGCO's actual costs, including a return on investment capital.
- *BHUH and its affiliates will not enter into transactions with an affiliate unless the transaction is in the ordinary course of business upon fair and reasonable terms that are consistent with market terms for similar transactions entered into by unaffiliated parties*: As noted in the direct testimony of Aaron Carr, any

acquisition of reserves from BHEP under the COSG Program would have to be a fair market transaction in the ordinary course of business. Any other transactions between BHUH (or the BHUH utilities) with an affiliate will be in the ordinary course of business and upon fair and reasonable terms.

- *Except where costs are charged in accordance with respective cost allocation commission manuals, a non-utility subsidiary or sister utility that receives a material benefit from a cost incurred by BHUH or its utilities will be charged a portion of those costs to compensate BHUH or its respective utilities*: Under the COSG Program, no BHUH indirect costs will be allocated to COSGCO. Only direct costs will be charged on a cost basis. Those costs will be part of the ROE calculation. In addition, no non-utility subsidiary or sister utility will receive a material benefit from a cost incurred by BHUH or the BHUH Utilities.
- *BHC will operate its utility businesses in accordance with prudent utility standards and practices, and will not engage in any practice, with respect to the allocation, assignment or distribution of capital, shared expenses or other costs, that is unduly discriminatory or preferential. All costs and expenses are shared in proportion to participation*: As noted, the Company believes the COSG Program and the COSG Agreement are consistent with prudent utility practice. No part of the COSG Program will constitute discriminatory or preferential allocation, assignment, or distribution of capital, shared expenses or other costs.

Q. IN CONCLUSION, CAN YOU PLEASE STATE AGAIN WHAT THE COMPANY IS REQUESTING IN ITS APPLICATION.

A. The Company is asking for a determination that the COSG Program, including the COSG Agreement, is prudent for the Company to pursue and that the amounts associated with the COSG Program are eligible for recovery. The Primary benefit of the COSG Program is long-term price stability because it narrows the range in gas supply costs. Because the current environment allows market participants to purchase gas reserve interests at favorable prices and drill to make those reserves productive, the COSG Program would allow the Company to establish a long-term physical hedge against the market instability and volatility described above. A secondary benefit is the reasonably anticipated potential savings for customers over the life of the reserves.

In addition, the Company is requesting that the Commission:

1. Authorize the Company to enter into the COSG Agreement, which incorporates (a) acquisition and drilling criteria; (b) an expedited process for Commission review of acquisition opportunities and drilling plans; and (c) other guidelines to protect the Company’s customers, including (i) Commission review of all proposed acquisitions and of drilling plans every five years; (ii) the retention by COSGCO of a mutually-acceptable hydrocarbon monitor (the “Hydrocarbon Monitor”) that would review potential acquisitions and drilling plans, and (iii) the retention by COSGCO of a mutually-acceptable accounting monitor (the “Accounting Monitor”) that would assess BHUH’s calculations under the COSG Program’s operations as provided in the COSG Agreement and provide an assurance report based on its assessment; and

2. Approve the revised tariff sheets that incorporate the provisions specified in the COSG Agreement necessary to allow recovery of the amounts necessary for

the COSG Program, including the application of “Hedge Credits” and “Hedge Costs”;

3. Approve the requested 50% hedge-participation level based on the Company’s forecasted annual firm demand or, in the alternative, a revised percentage that the Commission may determine; and

4. To the extent necessary, grant any waivers from affiliate rules or regulations or ring-fencing commitments, the Commission deems applicable.

IX. <u>CONCLUSION</u>

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

COST OF SERVICE GAS AGREEMENT

This COST OF SERVICE GAS AGREEMENT ("**COSG Agreement**"), dated September 15, 2015, is by and between BLACK HILLS UTILITY HOLDINGS, INC., a South Dakota corporation, ("**BHUH**") and the following (each a "**Utility**" and collectively the "**Utilities**"): BLACK HILLS POWER, INC., a South Dakota corporation; BLACK HILLS/COLORADO ELECTRIC UTILITY COMPANY, LP, a Delaware limited partnership; BLACK HILLS/COLORADO GAS UTILITY COMPANY, LP, a Delaware limited partnership; BLACK HILLS/IOWA GAS UTILITY COMPANY, LLC, a Delaware limited liability company; BLACK HILLS/KANSAS GAS UTILITY COMPANY, LLC, a Kansas limited liability company; BLACK HILLS/NEBRASKA GAS UTILITY COMPANY, LLC, a Delaware limited liability company; BLACK HILLS NORTHWEST WYOMING GAS UTILITY COMPANY, LLC, a Wyoming limited liability company; and CHEYENNE LIGHT, FUEL AND POWER COMPANY, a Wyoming corporation. BHUH and Utilities are referred to individually as a "**Party**" and collectively as the "**Parties**."

RECITALS

A. BHUH purchases natural gas for, or on behalf of, each Utility.

B. Each Utility desires for BHUH to cause physical reserves of natural gas to be acquired and developed pursuant to this COSG Agreement to (i) reduce volatility in the price for natural gas, (ii) hedge against long-term increases in the market price for natural gas, and (iii) reduce long-term costs to its customers by using a cost-based, rather than market-based, approach to meeting a portion of its natural gas needs.

NOW, THEREFORE, the Parties agree as follows:

ARTICLE 1 - DEFINITIONS

The following terms shall have the following meanings:

"**Accounting Monitor**" means an independent, third-party certified public accountant.

"**Acquisition Criteria**" means the criteria set forth in attached Exhibit A.

"**Actual ROE**" means the percentage obtained by dividing Net Income by Invested Equity.

"**Affiliated Utility**" means each Utility for which BHUH acts as agent when buying Gas, namely Black Hills Power, Inc., Black Hills Northwest Wyoming Gas Utility Company, LLC, and Cheyenne Light, Fuel and Power Company.

"**Allowed Cost of Debt**" means the weighted average of the following: (i) the cost of long-term debt, if any, of COSGCO, and (ii) for the balance of forty percent (40%) of Investment Base, the weighted average of Black Hills Corporation's cost of long-term debt.

"**Allowed ROE**" means the average of the annual return on equity in all gas and electric utility rate cases for the calendar year, as subsequently reported by Regulatory Research Associates, *provided* that if less than twenty (20) gas and electric utility rate cases are reported for a calendar year, then Allowed ROE for that calendar year shall equal the average of (i) the average of the annual return on equity in all gas and electric utility rate cases for that calendar year, and (ii) the average of the annual return on equity in all gas and electric utility rate cases for the prior calendar year, all as reported by Regulatory Research Associates.

"**BHUH**" is defined in the introductory paragraph of this COSG Agreement.

"**COSG Agreement**" is defined in the introductory paragraph of this COSG Agreement.

"**COSG Cost Forecast**" is defined in Section 4.2(xiv).

"**COSGCO**" means wholly-owned subsidiary of BHUH that is operated for the purpose of implementing this COSG Agreement.

"**COSGCO Gas**" means COSGCO's Gas produced from the Properties.

"**COSGCO OpEx**" means COSGCO's expenses, calculated in accordance with GAAP, including without limitation the costs of management, attorneys, consultants, operating expenses, fees and charges paid to the operator, gathering, transportation, compression, line loss and unaccounted for gas costs, minimum daily quantity penalties, processing, marketing, royalties, depreciation, amortization and depletion (including accruals for future plugging, abandonment, and other anticipated asset retirement expenses calculated using engineering estimates and GAAP), Taxes, and direct charges from BHUH and its affiliates for time spent providing services for the benefit of COSGCO, *provided* that (i) COSGCO OpEx shall include BHUH's costs for the Monitors, (ii) depletion shall be calculated on a unit of production basis using the "full cost method" but limited to proved developed producing reserves, (iii) depletion shall include the costs to identify and evaluate potential properties that do not become Properties under this COSG Agreement, and (iv) COSGCO's actual interest expense shall be replaced with an amount equal to the Allowed Cost of Debt multiplied by Investment Base multiplied by forty percent (40%).

"**COSGCO Revenue**" means the net proceeds received by COSGCO from the sale of Hydrocarbons produced from the Properties.

"**Cost of Capital**" shall be an imputed weighted average consisting of forty percent (40%) Allowed Cost of Debt and sixty percent (60%) Allowed ROE.

"**Drilling Plan**" means the plan approved under Section 4.3 or Section 4.4, as applicable, to drill wells on a Property.

"**Drilling Plan Criterion**" means the criterion set forth in attached Exhibit B.

"**Drilling Plan II**" means a plan approved under Section 4.5 to drill wells on a Property after the twentieth (20th) anniversary of the First Acquisition Date.

“**Dth**” means dekatherm.

“**Early Termination Amount**” is defined in Section 6.4.

“**Effective Date**” means the date the condition subsequent in Section 8.1 is satisfied or, if not satisfied, the date this COSG Agreement is deemed effective pursuant to Section 8.1.

“**First Acquisition Date**” means the date the first Property acquisition closes.

“**Five-Year Anniversary**” means the fifth (5th), tenth (10th), and fifteenth (15th) anniversaries of the First Acquisition Date.

“**Force Majeure Event**” is defined in Section 9.4.

“**Forecast Period**” means the six (6) months in each calendar year from (i) January 1 to June 30, and (ii) July 1 to December 31.

“**GAAP**” means generally accepted accounting principles as recognized by the American Institute of Certified Public Accountants, as in effect from time to time, consistently applied and maintained on a consistent basis by BHUH throughout the applicable period and consistent with BHUH’s prior financial practice.

“**Gas**” means any mixture of gaseous Hydrocarbons or of Hydrocarbons and other gasses, in a gaseous state, consisting primarily of methane, and excluding condensate and NGLs.

“**Hedge Cost**” is defined in Section 5.1(ii).

“**Hedge Credit**” is defined in Section 5.1(i).

“**Hedge Forecast Amounts**” is defined in Section 5.2.

“**Hedge Quantity**” is defined in Section 3.3.

“**Hedge Target**” means, for each Utility, fifty percent (50%) of its anticipated annual natural gas demand, *provided* that anticipated annual natural gas demand shall be (i) for a gas utility, its weather-normalized annual firm demand, (ii) for Black Hills Power, Inc., 600,000 Dths per year, which shall increase annually by 1.25%, (iii) for Black Hills/Colorado Electric Utility Company, LP, 10,500,000 Dth per year, which shall increase annually by 0.87%, and (iv) for Cheyenne Light, Fuel and Power Company (elec.), 400,000 Dths per year, which shall increase annually by 1.25%.

“**Hedge Year-End Amount**” is defined in Section 5.3.

“**Hydrocarbon Monitor**” means an independent third party with substantial experience evaluating oil and gas transactions.

“**Hydrocarbons**” means hydrocarbons, in either liquid or gaseous form, including Gas, condensate, NGLs, and oil.

"**Invested Equity**" means the product of Investment Base and sixty percent (60%).

"**Investment Base**" means the capitalized costs to identify, acquire and develop the Properties, including lease acquisition costs, capital investments, drilling, completion and equipping costs, and compression and gas gathering and processing capital costs, reduced by accumulated depletion, depreciation, amortization, and net accumulated deferred taxes, *provided* that (i) for purposes of calculating Investment Base in connection with Hedge Forecast Amounts under Section 5.2 and the Hedge Year-End Amount under Section 5.3, if there are no capitalized costs at the beginning of the relevant period, then the period for calculating Investment Base shall commence when capitalized costs are incurred,[1] and (ii) the capitalized costs to identify and acquire a Property shall be allocated to proved developed producing reserves at the time of the acquisition and to proved undeveloped reserves developed under the Drilling Plan for the Property prior to the Five-Year Anniversary immediately following the Property's acquisition.

"**Long-Term Market Price Forecast**" shall mean the following, in nominal dollars:

(i) for Gas, the average of the most recent long-term "base case" Gas price forecast published by Ventyx and the long-term "reference case" Gas price forecast published by the U.S. Energy Information Administration in its most recent "Annual Energy Outlook";

(ii) for NGLs, a commercially reasonable price forecast based on available public information;

(iii) for all other Hydrocarbons (excluding Gas and NGLs), the average of the most recent long-term "base case" crude oil price forecast published by Ventyx and the long-term "reference case" crude oil price forecast published by the U.S. Energy Information Administration in its most recent "Annual Energy Outlook,"

Provided that (a) the locational basis of each forecast shall be adjusted to correspond with the respective delivery point for COSGCO's Hydrocarbons, (b) inflation shall be forecast using the inflation percentage used by the U.S. Energy Information Administration in its most recent "Annual Energy Outlook," and (c) if a forecast does not extend through the end of the period covered by the applicable Reserve Report, then the forecast price for the last year of that forecast shall be escalated annually by the aforementioned inflation percentage.

"**Monitors**" means the Accounting Monitor and the Hydrocarbon Monitor.

"**Net Cap. Costs**" is defined in Section 6.4.

[1] For example only, if COSGCO paid $50 million to acquire its first Property on March 15, then Investment Base for purposes of calculating the Hedge Year-End Amount pursuant to Section 5.3 for that calendar year would be the average of COSGCO's capitalized costs on March 15, March 31, and the end of each subsequent calendar month in that calendar year.

"**Net Income**" means COSGCO Revenue minus COSGCO OpEx, calculated in accordance with GAAP.

"**Net Op. Costs**" is defined in Section 6.4.

"**NGLs**" means those liquid Hydrocarbons, excluding condensate, obtained by processing gas.

"**Non-Participating Utility**" means, with respect to any Property, a Utility (i) whose PUC determines pursuant to Section 4.3 that the Property's proposed acquisition does not satisfy the Acquisition Criteria, (ii) whose PUC determines pursuant to Section 4.4 that an updated Drilling Plan does not satisfy the Drilling Plan Criterion, or (iii) that either determines it does not want to participate in further development of the Properties after the twentieth (20th) anniversary of the First Acquisition Date or whose PUC determines pursuant to Section 4.5 that a Drilling Plan II does not satisfy the Drilling Plan Criterion.

"**Party**" and "**Parties**" are defined in the introductory paragraph of this COSG Agreement.

"**Percentage Share**" means, for each Utility, its then-applicable Hedge Target divided by the Utilities' then-applicable aggregate Hedge Target.

"**PGA/GCA/ECA Filing**" means, with respect to each Utility, its purchased gas adjustment, gas cost adjustment or energy cost adjustment filing.

"**Property**" and "**Properties**" means any property approved pursuant to Section 4.3 in which COSGCO acquires interests, or the right to earn interests through drilling.

"**Proposed Drilling Program**" is defined in Section 4.2(ii).

"**PUC**" means the Colorado Public Utilities Commission with respect to Black Hills/Colorado Gas Utility Company, LP and Black Hills/Colorado Electric Utility Company, LP; Iowa Utilities Board with respect to Black Hills/Iowa Gas Utility Company, LLC; Kansas Corporation Commission with respect to Black Hills/Kansas Gas Utility Company, LLC; Nebraska Public Service Commission with respect to Black Hills/Nebraska Gas Utility Company, LLC; South Dakota Public Utilities Commission with respect to Black Hills Power, Inc.; and Wyoming Public Service Commission with respect to Black Hills Power, Inc., Cheyenne Light, Fuel and Power Company and Black Hills Northwest Wyoming Gas Utility Company, LLC.

"**Reserve Report**" is defined in Section 4.2(xii).

"**T**" means the highest marginal statutory federal income tax rate applicable to corporations combined with applicable state statutory income tax rates, in effect for the year in question.

"**Taxes**" means all taxes, charges, fees, duties, levies, or other assessments, however, denominated, imposed by any federal, state, or local government or any agency or political subdivision of any such government, including, without limiting the generality of the foregoing, income or profit, gross receipts, net proceeds, ad valorem, real and personal property (tangible and intangible), possessory interest, sales, use, franchise, excise, value added, stamp, leasing, lease, business license, user, transfer, fuel, environmental, excess profits, occupational, interest equalization, windfall profits, severance and employees' income withholding, workers' compensation, Pension Benefits Guaranty Corporation premiums, unemployment and Social Security taxes, and other obligations of the same or of a similar nature to any of the foregoing (all including any interest, penalties or additions to tax related thereto imposed by any taxing authority).

"**Term**" is defined in Section 6.1.

"**Utility**" and "**Utilities**" are defined in the introductory paragraph of this COSG Agreement, *provided* that notwithstanding anything to the contrary (i) with respect to Black Hills Power, Inc., this COSG Agreement only pertains to its utility operations in South Dakota and Wyoming, (ii) the gas and electric utility operations of Cheyenne Light, Fuel and Power Company shall each be considered a separate Utility, and (iii) Utility and Utilities does not include any Utility whose PUC has not approved this COSG Agreement in full and without modification in an order satisfactory to BHUH and the Utility.

ARTICLE 2 - MONITORS

Section 2.1 Accounting Monitor; Hydrocarbon Monitor. BHUH shall retain the Accounting Monitor and Hydrocarbon Monitor, each mutually agreeable to BHUH and the PUCs. The Accounting Monitor shall prepare assurance reports regarding the accuracy of BHUH's calculations under this COSG Agreement pursuant to Section 5.5. The Hydrocarbon Monitor shall assess the following: (i) whether each proposed acquisition satisfies the Acquisition Criteria pursuant to Section 4.3; (ii) whether each Drilling Plan and Drilling Plan II satisfies the Drilling Plan Criterion pursuant to Section 4.4 and Section 4.5, respectively; and (iii) whether COSGCO's reserves in the annual report described in Section 5.5 were calculated in accordance with standard industry practice.

Section 2.2 Communications. The Monitors shall be available to BHUH, the Utilities, and the PUCs. BHUH, the Utilities, and the PUCs shall be given advance notice, reasonable under the circumstances, of and afforded the opportunity to join any discussions with the Monitors and shall be copied on all written communications to/from the Monitors.

Section 2.3 Records; Confidentiality. BHUH and COSGCO's books, accounts, and records regarding the Properties and this COSG Agreement shall be available to the Monitors, each Utility, and each PUC for inspection at any reasonable time with prior notice. The Monitors and the PUCs shall each not disclose to any third party any information or other communications to or from BHUH, COSGCO, one or both of the Monitors, or any PUC(s) without the prior written consent of BHUH and the PUCs.

ARTICLE 3 - GAS PURCHASE

Section 3.1 Gas Purchase. In accordance with BHUH's role as purchaser of Gas for, or on behalf of, each Utility pursuant to prior PUC precedent and rules, during the Term each

Utility shall continue to reimburse BHUH for the costs BHUH incurs purchasing Gas on the market for, or on behalf of, the Utility, including the Utility's Hedge Quantity, *provided* that BHUH shall not purchase, directly or indirectly, Gas produced from the Properties unless mutually agreeable to all Parties pursuant to a written addendum to this COSG Agreement executed by all Parties. In addition, during the Term each Utility shall receive any credits and incur any costs required under ARTICLE 5.

Section 3.2 Hedge Target. On or before November 1 of each year, each Utility shall provide BHUH with its Hedge Target for each remaining year in the Term. Each Utility's Hedge Target and Percentage Share for 2016 are set forth in attached Exhibit C. Notwithstanding anything to the contrary in this COSG Agreement, a Utility's Hedge Target shall not decrease in any year unless such decrease can be accommodated pursuant to Section 3.4.

Section 3.3 Hedge Quantity. Each Utility's "**Hedge Quantity**" in each calendar month during the Term shall be a quantity of Gas equal to the Utility's Percentage Share multiplied by the quantity of COSGCO Gas produced during that calendar month, *provided* that the Utility's Hedge Quantity shall not exceed its Hedge Target unless (i) the Utility experiences a decrease in its Hedge Target as set forth in Section 3.4, in which case its Hedge Quantity may temporarily exceed its Hedge Target while BHUH seeks to accommodate such decrease pursuant to Section 3.4, or (ii) the Properties produce more Gas than anticipated by the Drilling Plans, in which case the Utility's Hedge Quantity may temporarily exceed its Hedge Target while one or more of the Drilling Plans is adjusted to decrease production from the Properties.

Section 3.4 Decrease to a Utility's Hedge Target. If a Utility experiences, after adjusting for weather normalization, a ten percent (10%) or more decrease to its anticipated natural gas demand that was used in calculating its Hedge Target and the Utility reasonably expects such reduced demand will continue, then BHUH shall take all reasonable steps to accommodate such decrease as soon as reasonably practicable, including the following:

(i) Adjusting the Drilling Plan(s) as soon as reasonably practicable to decrease production from the Properties to account for such decrease; and/or

(ii) Decreasing the Utility's Percentage Share to account for such decrease and increasing the other Utilities' Percentage Shares but only (i) with each of the other Utilities' prior consent, and (ii) to the extent that each of the other Utilities' resulting Hedge Quantity does not exceed its Hedge Target,

Provided that until BHUH is able to accommodate such a change, this COSG Agreement shall continue to apply to the Utility's full Hedge Quantity before such reduction in demand and the Utility shall accept any credits and incur any costs required under ARTICLE 5 calculated using the Utility's full Hedge Quantity before such reduction in demand.

ARTICLE 4 - PROPERTIES

Section 4.1 Property Acquisition and Development. For the twenty (20) years following the First Acquisition Date, BHUH shall cause COSGCO to acquire interests, or the right to earn interests through drilling, in one or more properties and to develop each Property in accordance with its Drilling Plan to increase and maintain COSGCO Gas production up to the

Utilities' aggregate Hedge Target subject to the processes and PUC oversight described in this ARTICLE 4 and to the extent commercially feasible. BHUH shall cause COSGCO to endeavor to increase COSGCO Gas production up to the Utilities' aggregate Hedge Target as soon as practical after the Effective Date and then to maintain COSGCO Gas production at the Utilities' aggregate Hedge Target until the twentieth (20th) anniversary of the First Acquisition Date, *provided* that, notwithstanding anything to the contrary in this COSG Agreement, this obligation shall be subject to the following:

(i) BHUH's determination, in its sole discretion, regarding the maximum capital expenditure to be made with respect to any proposed acquisition, the availability of property(ies) that satisfy the Acquisition Criteria, and the annual schedule for capital expenditures by COSGCO on acquisition and development; and

(ii) The processes and PUC oversight described this ARTICLE 4.

BHUH shall cause COSGCO to limit its business activities to identifying and evaluating potential Property acquisitions; acquiring, developing and operating the Properties; marketing and selling Hydrocarbons produced from the Properties; and conducting other activities related to operating the Properties. For the avoidance of doubt, except as expressly provided this ARTICLE 4, decisions regarding the development and operation of the Properties, including without limitation well locations, shall be made solely by COSGCO as directed by BHUH.

Section 4.2 Acquisition Information. BHUH shall provide the Hydrocarbon Monitor with the following information concerning each proposed COSGCO acquisition that BHUH wants to become a Property under this COSG Agreement:

(i) Price and terms of the proposed acquisition by COSGCO, including any joint operating agreement(s) to which COSGCO would become bound;

(ii) A plan to drill wells on a schedule intended, to the extent commercially feasible, to develop and maintain reasonably stable production from the property for a period of at least five (5) years ("**Proposed Drilling Program**"), *provided* that proposed acquisitions that are fully developed or that have a Proposed Drilling Program less than five (5) years in length can become Properties under this COSG Agreement if the Acquisition Criteria are satisfied;

(iii) Gross working interest and net revenue interest to be acquired or earned by COSGCO in existing wells, if any, and wells to be developed through execution of the Proposed Drilling Program;

(iv) Historical production from and remaining reserves of existing wells;

(v) Forecast reserves for wells to be developed through execution of the Proposed Drilling Program;

(vi) Forecast production for existing wells and wells to be developed through execution of the Proposed Drilling Program, showing aggregate production per year;

(vii) A summary of geologic and geophysical data;

(viii) Historical exploration, drilling and operating costs (including gathering and processing costs) of existing wells;

(ix) Forecast operating costs (including gathering and processing costs) of existing wells;

(x) Forecast capital and operating costs (including gathering and processing costs) for future wells;

(xi) Estimated production tax for existing wells and to be developed through execution of the Proposed Drilling Program;

(xii) A third-party engineering report (the "**Reserve Report**") assessing, using the then-current Long-Term Market Price Forecast, (1) the proved reserves (including without limitation proved undeveloped reserves) and any probable reserves to be developed through execution of the Proposed Drilling Program, (2) the forecast production for existing wells and wells to be developed through execution of the Proposed Drilling Program, and (3) the estimated cost to develop the proved reserves through execution of the Proposed Drilling Program and the projected costs per Dth for existing and to-be-developed reserves as produced;

(xiii) Then-current Long-Term Market Price Forecast;

(xiv) The "**COSG Cost Forecast**," which means, for each year of the Reserve Report, the forecast Gas cost calculated in nominal dollars pursuant to the following formula:

*COSG Cost Forecast = [COSGCO OpEx + (Cost of Capital * Investment Base)] - Liquids Revenue*

Provided that (i) "Liquids Revenue" means the money COSGCO is anticipated to receive from the sale of all Hydrocarbons other than Gas, and (ii) the then-current Long-Term Market Price Forecast and the Proposed Drilling Program, Drilling Plan or Drilling Plan II, as applicable, shall be used in calculating the COSG Cost Forecast;

(xv) Description of any material lease, title, and legal issues known by COSGCO concerning the proposed acquisition;

(xvi) A consultant's report describing environmental and regulatory permits and permit compliance for the existing wells and infrastructure related to the proposed acquisition; and

(xvii) Other data as BHUH may deem to be appropriate to an evaluation of the proposed acquisition.

Section 4.3 <u>Acquisition Oversight</u>. Within ten (10) calendar days following receipt of all the information described in Section 4.2, the Hydrocarbon Monitor shall issue a written report to BHUH, the Utilities, and the PUCs regarding whether the proposed acquisition satisfies the Acquisition Criteria.

If the Hydrocarbon Monitor determines that the proposed acquisition does not satisfy the Acquisition Criteria, then the proposed acquisition shall not be deemed a Property under this COSG Agreement, *provided* such a determination shall not preclude BHUH from subsequently seeking approval under this Section 4.3 for the same proposed acquisition.

If the Hydrocarbon Monitor determines that the proposed acquisition satisfies the Acquisition Criteria and no PUC reaches a contrary determination in a formal, adjudicative proceeding concluded within sixty (60) calendar days after receipt of the Hydrocarbon Monitor's report, then the following shall occur upon the closing of the acquisition: the proposed acquisition shall be deemed a Property under the terms of this COSG Agreement, the Proposed Drilling Program shall become the Drilling Plan for the Property, and BHUH shall cause COSGCO to develop the Property until the next Five-Year Anniversary in accordance with the Drilling Plan, unless adjusted pursuant to Section 3.3 or Section 3.4, and without further PUC action.

If the Hydrocarbon Monitor determines that the proposed acquisition satisfies the Acquisition Criteria but one or more PUCs reach a contrary determination in a formal, adjudicative proceeding concluded within sixty (60) calendar days after receipt of the Hydrocarbon Monitor's report, then, if BHUH directs COSGCO to move forward with the proposed acquisition, the following shall occur upon the closing of the acquisition:

(i) The proposed acquisition shall be deemed a Property under the terms of this COSG Agreement, the Proposed Drilling Program shall become the Drilling Plan for the Property, and BHUH shall cause COSGCO to develop the Property until the next Five-Year Anniversary in accordance with the Drilling Plan, unless adjusted pursuant to Section 3.3 or Section 3.4, and without further PUC action, *provided* that if BHUH determines that the Proposed Drilling Program needs to be modified to account for the non-participation of a Non-Participating Utility in the Property, then (1) BHUH shall first make such modifications to the Proposed Drilling Program, and (2) the proposed acquisition shall not become a Property unless the Hydrocarbon Monitor issues a written report concluding that the proposed acquisition (with the modified Proposed Drilling Program) satisfies the Acquisition Criteria, in which case the modified Proposed Drilling Program shall become the Drilling Plan for the Property, and BHUH shall cause COSGCO to develop the Property until the next Five-Year Anniversary in accordance with that Drilling Plan, unless adjusted pursuant to Section 3.3 or Section 3.4, and without further PUC action;

(ii) Any capital and operating expenses incurred by COSGCO to acquire, develop and operate the Property and any production from the Property shall not be used when calculating the Hedge Quantity and any credits and costs under ARTICLE 5 for a Non-Participating Utility, and a Non-Participating Utility shall neither receive any credits nor incur any costs under ARTICLE 5 with respect to the Property; and

(iii) A Non-Participating Utility and its PUC shall have no rights or obligations with respect to the Property under Section 4.4.

Section 4.4 Five-Year Drilling Plan Review. No later than seventy (70) calendar days before each Five-Year Anniversary, BHUH shall provide the Hydrocarbon Monitor with the information described in Section 4.2(iii)-(xiv) for each Property, the Utilities' aggregate Hedge Target for each remaining year in the twenty (20) year period following the First Acquisition Date, and an updated Drilling Plan for each Property for such period. BHUH may seek approval for an updated Drilling Plan for any Property at any other time by providing the Hydrocarbon Monitor with the information described in Section 4.2(iii)-(xiv) for the Property, the Utilities' aggregate Hedge Target for each remaining year in the twenty (20) year period following the First Acquisition Date, and an updated Drilling Plan the Property for such period.

Within ten (10) calendar days following receipt of said information, the Hydrocarbon Monitor shall issue a written report to BHUH, the Utilities, and the PUCs regarding whether the updated Drilling Plan(s) satisfies the Drilling Plan Criterion.

If the Hydrocarbon Monitor determines that an updated Drilling Plan does not satisfy the Drilling Plan Criterion, then BHUH shall cause COSGCO to not participate in the drilling of any new production wells on the Property until an updated Drilling Plan has been approved under this Section 4.4.

If the Hydrocarbon Monitor determines that an updated Drilling Plan satisfies the Drilling Plan Criterion and no PUC reaches a contrary determination in a formal, adjudicative proceeding concluded within sixty (60) calendar days after receipt of the Hydrocarbon Monitor's report, then BHUH shall cause COSGCO to develop the Property until the next Five-Year Anniversary in accordance with the Drilling Plan, unless adjusted pursuant to Section 3.3 or Section 3.4, and without further PUC action.

If the Hydrocarbon Monitor determines that the updated Drilling Plan satisfies the Drilling Plan Criterion but one or more PUCs reach a contrary determination in a formal, adjudicative proceeding concluded within sixty (60) calendar days after receipt of the Hydrocarbon Monitor's report, then the following shall occur:

(i) BHUH shall cause COSGCO to develop the Property until the next Five-Year Anniversary in accordance with the Drilling Plan, unless adjusted pursuant to Section 3.3 or Section 3.4, and without further PUC action, *provided* that if BHUH determines that the Drilling Plan needs to be modified to account for the non-participation of a Non-Participating Utility in the updated Drilling Plan, then (1) BHUH shall first make such modifications to the updated Drilling Plan, and (2) BHUH shall cause COSGCO to not develop the Property in accordance with that modified Drilling Plan unless the Hydrocarbon Monitor issues a written report concluding that the modified Drilling Plan satisfies the Drilling Plan Criterion, in which case BHUH shall cause COSGCO to develop the Property until the next Five-Year Anniversary in accordance with that Drilling Plan, unless adjusted pursuant to Section 3.3 or Section 3.4, and without further PUC action;

(ii) Any capital and operating expenses incurred by COSGCO to develop and operate additional wells on the Property after the effective date of the updated Drilling Plan and any production from such wells shall not be used when calculating the Hedge Quantity and the credits and costs under ARTICLE 5 for a Non-Participating Utility; and

(iii) A Non-Participating Utility and its PUC shall have no further rights or obligations with respect to the Property under this Section 4.4.

Section 4.5 Drilling Plan II. Notwithstanding anything to the contrary in this COSG Agreement, following the twentieth (20th) anniversary of the First Acquisition Date COSGCO shall not continue drilling new production wells on the Properties except as provided in this Section 4.5, *provided* that BHUH shall cause COSGCO to continue producing Hydrocarbons from the wells COSGCO acquired or drilled prior to such twentieth (20th) anniversary and each Utility shall continue to receive any credits and incur any costs required under ARTICLE 5 until the expiration or early termination of this COSG Agreement. If BHUH anticipates that opportunities to further develop one or more of the Properties may exist on the twentieth (20th) anniversary of the First Acquisition Date and one or more Utilities (but with respect to any Property with further development opportunities, excluding any Non-Participating Utility) desire for BHUH to cause COSGCO to participate in such opportunities, then BHUH shall provide the Hydrocarbon Monitor with Drilling Plan II for each such Property and the information described in Section 4.2(iii)-(xiv) for each such Property no later than seventy (70) calendar days before the twentieth (20th) anniversary of the First Acquisition Date. Drilling Plan II(s) shall then be subject to the review process, criterion, and other terms set forth in the second through fifth paragraphs of Section 4.4.

Section 4.6 Opportunity for Non-Participating Utilities to Participate in Subsequent Drilling Plans. Notwithstanding anything to the contrary in Section 4.3 and Section 4.4, BHUH may propose that a Non-Participating Utility participate in new production wells to be drilled pursuant to an updated Drilling Plan for the Property in which the Non-Participating Utility is not participating, *provided* that in such situation, the following provisions shall supplement the review of the updated Drilling Plan under Section 4.4:

(i) In addition to providing the information identified in Section 4.4, BHUH shall provide the Hydrocarbon Monitor with information describing why and/or how the proposed participation of the Non-Participating Utility in such updated Drilling Plan is not anticipated to be detrimental to the other Utilities participating in the Property;

(ii) If the Hydrocarbon Monitor, in addition to determining that the updated Drilling Plan satisfies the Drilling Plan Criterion, concurs with BHUH in the written report called for under Section 4.4, then the updated Drilling Plan shall be subject to the fourth and fifth paragraphs of Section 4.4 and

1) If either the PUC for the Non-Participating Utility reaches a contrary determination in a formal, adjudicative proceeding concluded within sixty (60) calendar days after receipt of the Hydrocarbon Monitor's report or one or more of the PUCs for the other Utilities participating in the Property objects within such sixty (60) calendar day period to the proposed participation of the

Non-Participating Utility, then the Non-Participating Utility shall remain a Non-Participating Utility with respect to new production wells drilled pursuant to the updated Drilling Plan; but

2) If the PUC for the Non-Participating Utility does not reach a contrary determination in a formal, adjudicative proceeding concluded with such sixty (60) calendar day period and none of the PUCs for the other Utilities participating in the Property objects within such sixty (60) calendar day period, then the Non-Participating Utility shall participate in new production wells drilled pursuant to the updated Drilling Plan, any capital and operating expenses incurred by COSGCO to develop and operate additional wells on the Property after the effective date of the updated Drilling Plan and any production from such wells shall be used when calculating the Hedge Quantity and the credits and costs under ARTICLE 5 for the Non-Participating Utility, and the Non-Participating Utility and its PUC shall have further rights and obligations with respect to the Property under Section 4.4.

ARTICLE 5 - HEDGE SETTLEMENT

Section 5.1 Hedge Settlement. After the end of each calendar month, BHUH shall calculate a Hedge Credit pursuant to Section 5.1(i) or a Hedge Cost pursuant to Section 5.1(ii), as applicable.[2]

(i) Hedge Credit. If Actual ROE for a calendar month is more than one hundred (100) basis points greater than Allowed ROE, then a "**Hedge Credit**" for such calendar month shall be calculated pursuant to the following formula:

$$\textit{Hedge Credit} = -\,(\textit{Net Income} - ((\textit{Allowed ROE} + 100 \textit{ basis points}) * \textit{Invested Equity})) * \frac{1}{(1 - T)}$$

Each Utility's Percentage Share of the Hedge Credit shall be credited against the amount the Utility owes to BHUH for all Gas that BHUH purchased on the market for, or on behalf of, the Utility in that calendar month, *provided* that BHUH shall instead pay each Affiliated Utility its Percentage Share of the Hedge Credit within thirty (30) days following the end of that calendar month.

(ii) Hedge Cost. If Actual ROE for a calendar month is more than one hundred (100) basis points less than Allowed ROE, then a "**Hedge Cost**" for such calendar month shall be calculated pursuant to the following formula:

$$\textit{Hedge Cost} = -\,(\textit{Net Income} - ((\textit{Allowed ROE} - 100 \textit{ basis points}) * \textit{Invested Equity})) * \frac{1}{(1 - T)}$$

[2] Sample calculations of a Hedge Credit and Hedge Cost are shown in attached Exhibit D for illustrative purposes only.

Each Utility's Percentage Share of the Hedge Cost shall be included as a cost in the amount the Utility owes to BHUH for all Gas that BHUH purchased on the market for, or on behalf of, the Utility in that calendar month, *provided* that each Affiliated Utility shall instead pay BHUH its Percentage Share of the Hedge Cost within thirty (30) days following the end of that calendar month.

Section 5.2 Utility Hedge Forecast. To establish reasonably accurate rates in advance for the Utilities' customers, BHUH shall do the following before the start of each Forecast Period: (i) forecast Actual ROE for each calendar month of that Forecast Period using the average of the forecast Investment Base for each calendar month in that Forecast Period; and (ii) forecast a Hedge Credit calculated pursuant to Section 5.1(i) or a Hedge Cost calculated pursuant to Section 5.1(ii), as applicable, for each calendar month of that Forecast Period (collectively, the "**Hedge Forecast Amounts**") using the most recent Allowed ROE. To help minimize annual reconciliations under Section 5.3, the Hedge Forecast Amounts may also include an adjustment to reflect anticipated differences between the Hedge Forecast Amounts for an unreconciled Forecast Period(s) and COSGCO's actual results to date in that calendar year. Each Utility shall incorporate its Percentage Share of the Hedge Forecast Amounts into its rates for the Forecast Period in accordance with its approved tariffs and adjustment mechanisms.

Notwithstanding anything to the contrary in the immediately preceding paragraph, (i) until the First Acquisition Date, the Hedge Forecast Amounts shall be zero, and (ii) concurrent with the closing of the acquisition of any Property, BHUH shall update the Hedge Forecast Amounts for the remainder of the then-current Forecast Period and each Utility shall incorporate its Percentage Share of the updated Hedge Forecast Amounts into its rates for the Forecast Period in accordance with its approved tariffs and adjustment mechanisms.

Section 5.3 Annual Hedge Reconciliation. To ensure that the Utilities and their customers are receiving the actual benefits or paying the actual costs of this COSG Agreement and to incorporate the actual Allowed ROE for each calendar year, BHUH shall do the following no later than ninety (90) calendar days after the end of each calendar year: (i) calculate Actual ROE for that prior calendar year; (ii) calculate the actual Hedge Credit or the actual Hedge Cost, as applicable, for that prior calendar year (the "**Hedge Year-End Amount**") using the Allowed ROE for that prior calendar year and the trailing thirteen (13) calendar month average of Investment Base; (iii) reconcile the Hedge Year-End Amount with the aggregate Hedge Credits and Hedge Costs credited or billed to each Utility pursuant to Section 5.1 for that prior calendar year, including crediting each Utility its Percentage Share of any additional Hedge Credit amount and billing each Utility its Percentage Share of any additional Hedge Cost amounts consistent with Section 5.1; and (iv) reconcile the Hedge Year-End Amount with the Hedge Forecast Amounts calculated pursuant to Section 5.2 for that prior calendar year with each Utility then incorporating its Percentage Share of any additional Hedge Credit or Hedge Cost amounts into its rates for the next Forecast Period in accordance with its approved tariffs and adjustment mechanisms.

Section 5.4 Reporting. BHUH shall promptly report to each Utility the calculations of Hedge Forecast Amounts and Percentage Share, and each Utility shall file such information with its PUC as part of its next PGA/GCA/ECA Filing.

Section 5.5 Annual Report. After the Hedge Year-End Amount has been calculated for a calendar year, BHUH shall promptly prepare an annual report setting forth the following:

(i) For that calendar year, each Utility's Hedge Target and Percentage Share, Actual ROE, Allowed ROE, Hedge Forecast Amounts, Hedge Year-End Amount, and COSGCO's financial statements;

(ii) For each calendar month in that calendar year, the volume of Gas, NGLs and other Hydrocarbons that COSGCO sold; and

(iii) COSGCO's reserves as of the end of that calendar year.

The Hydrocarbon Monitor shall assess whether COSGCO's reported reserves were calculated in accordance with standard industry practice and shall document its findings in writing. The Accounting Monitor shall prepare an assurance report regarding the accuracy of BHUH's calculations under this COSG Agreement during that calendar year. BHUH shall promptly provide the annual report, the Hydrocarbon Monitor's findings, and the Accounting Monitor's assurance report to each Utility, and each Utility shall file such information with its PUC as part of its next PGA/GCA/ECA Filing.

If the Hydrocarbon Monitor concludes that COSGCO's reported reserves were not calculated in accordance with standard industry practice and BHUH and the Hydrocarbon Monitor cannot agree on the appropriate change, then a third-party reservoir engineer (mutually agreeable to BHUH and the Hydrocarbon Monitor) shall be retained to resolve the difference in opinion. If the Accounting Monitor concludes that BHUH's calculations were not accurate and BHUH and the Accounting Monitor cannot agree on the appropriate change, then each Utility shall refer the Accounting Monitor's proposed adjustment to its PUC for resolution.

Section 5.6 Indirect Costs. COSGCO shall not be included in BHUH's and Black Hills Service Company's respective "Cost Allocation Manual, and no indirect costs shall be allocated to BHUH's performance of this COSG Agreement or included in the calculations under ARTICLE 5. Direct charges from BHUH and its affiliates for time spent providing services for the benefit of COSGCO shall be included in COSGCO OpEx.

Section 5.7 Reserve Pool. For accounting purposes, COSGCO shall maintain its own reserve pools separate from Black Hills Exploration and Production, Inc., such reserve pools shall be limited to proved developed producing reserves, and in accordance with SEC Regulation S-X Rule 4-10, Investment Base shall not be subject to the cost center ceilings test.

ARTICLE 6 - TERM AND TERMINATION

Section 6.1 Term. This COSG Agreement shall be effective from the Effective Date and shall continue in full force and effect for each Utility until the existing wells on each Property at the time of acquisition by COSGCO and the wells BHUH causes COSGCO to drill on the Properties pursuant to the Drilling Plan(s) and Drilling Plan II(s) (but excluding any wells for which the Utility is a Non-Participating Utility) have been plugged and abandoned and the portions of the Properties affected by such wells reclaimed in accordance with applicable law ("**Term**"), *provided* that each Utility's rights and obligations under this COSG Agreement may be terminated early as provided below in this ARTICLE 6. Applicable provisions of this COSG Agreement shall continue in effect after expiration of this COSG Agreement or early termination to the extent necessary to (i) provide for final billings, payments and adjustments, and (ii) enforce or complete the duties, obligations or responsibilities of the Parties.

Section 6.2 Early Termination by Utility. If a Utility is ordered by its PUC to terminate its rights and obligations under this COSG Agreement before the end of the Term, the Utility shall provide notice to BHUH. 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). Following the sale, Investment Base shall be adjusted to reflect such sale(s). The termination of the terminating Utility's rights and obligations under this COSG Agreement shall be effective at the end of the calendar month in which the sale (or, if COSGCO sells such interest through multiple transactions, the last sale) closes, *provided* that (i) any amount due under Section 6.4 and any reconciliation amount owed under Section 5.3 shall be promptly paid, (ii) until such sale closes, the terminating Utility shall continue to receive any credits and incur any costs required under ARTICLE 5, and (iii) if no third party(ies) is willing to purchase such interest, the terminating Utility shall remain bound to this COSG Agreement until the end of the Term.

Section 6.3 Early Termination by BHUH. If BHUH determines, in its sole discretion, that any Non-Participating Utilities and/or terminating Utilities under Section 6.2 make continued performance of this COSG Agreement infeasible, BHUH may elect to terminate this COSG Agreement by providing notice to the Utilities. If BHUH elects to terminate, BHUH shall then cause COSGCO to sell, as soon as practical, all of its interest in the Properties, *provided* that no sale(s) shall occur until the Utilities have approved the sale price(s). The termination of the rights and obligations under this COSG Agreement shall be effective at the end of the calendar month in which the sale (or, if COSGCO sells its interests in the Properties through multiple transactions, the last sale) closes, *provided* that (i) any amount due under Section 6.4 and any reconciliation amount owed under Section 5.3 shall be promptly paid, (ii) until such sale closes, the Utilities shall continue to receive any credits and incur any costs required under ARTICLE 5, and (iii) if no third party(ies) is willing to purchase COSGCO's interests in the Properties, the Parties shall remain bound to this COSG Agreement until the end of the Term.

Section 6.4 Sale Proceeds. If the proceeds from a sale(s) under Section 6.2 or Section 6.3 (after deducting the transaction costs and Taxes incurred by BHUH or COSGCO in connection with such sale(s)) are greater than the Early Termination Amount multiplied by the Utility's Percentage Share for the calendar year in which the sale (or, if COSGCO sells through multiple transactions, the last sale) closes, then the difference shall be paid to the Utility and shall be incorporated into its rates as a credit to customers in accordance with its approved tariffs and adjustment mechanisms. If said proceeds are less than the Early Termination Amount multiplied by the Utility's Percentage Share for the calendar year in which such sale closes, then the Utility shall pay BHUH the difference and incorporate the difference into its rates as a cost to customers in accordance with its approved tariffs and adjustment mechanisms. No other Utility shall have any claim to any payment made under this Section 6.4.

BHUH shall calculate the "**Early Termination Amount**" pursuant to the following formula, as reasonably calculated by BHUH:

*Early Termination Amount = Net Cap. Costs + (Net Cap. Costs * Cost of Capital) + Net Op. Costs*

WHERE:

"**Net Cap. Costs**" shall be an amount equal to Investment Base (as defined in ARTICLE 1 but excluding any Properties and/or wells for which the relevant Utility is a Non-Participating Utility plus the estimated capitalized costs, if any, that COSGCO will remain obligated to pay in connection with the sold interests under any binding agreements with third parties) plus the net present value (in nominal dollars using the then-applicable Cost of Capital as the discount rate) of any minimum daily quantity penalties that COSGCO may incur as a result of the termination.

"**Net Op. Costs**" shall be an amount equal to the estimated operating costs, if any, that COSGCO will remain obligated to pay in connection with the sold interests under any binding agreements with third parties.

ARTICLE 7 - ADDITIONAL COVENANTS

Section 7.1 Neither BHUH nor the Utilities shall provide financing for, extend credit to, issue long-term debt for or pledge utility assets in support of the activities of COSGCO contemplated by this COSG Agreement.

Section 7.2 Neither BHUH nor the Utilities shall guarantee any new debt obligations, notes, debentures, or any other security of Black Hills Corporation, a South Dakota corporation, or its non-utility operations.

Section 7.3 Stand-alone or project financing for COSGCO's activities shall be without recourse to either BHUH or the Utilities.

ARTICLE 8 - CONDITION SUBSEQUENT

Section 8.1 This COSG Agreement shall have no force and effect unless and until each PUC has approved this COSG Agreement in full and without modification in orders satisfactory to BHUH and the Utilities, *provided* that if each PUC does not so approve this COSG Agreement, then BHUH and each Utility for which its respective PUC has so approved this COSG Agreement shall have the right, but not the obligation, to deem this COSG Agreement effective as to such Utility.

ARTICLE 9 - MISCELLANEOUS

Section 9.1 <u>Replacement Forecasts and Reports</u>. If a forecast that comprises part of the Long-Term Market Price Forecast ceases to be published or Regulatory Research Associates ceases to report the average annual return on equity in gas and electric utility rate cases, then BHUH shall promptly select an appropriate alternative forecast or report to achieve the same effect.

Section 9.2 Default; Remedies. If any Party fails or refuses to comply with any of the terms and conditions of this COSG Agreement, any other Party may notify that Party (and the other Parties) in writing of such alleged default, specifying the nature and character of the default. The defaulting Party shall have sixty (60) calendar days after receipt of such notice within which to initiate good-faith action to correct the alleged default, *provided* that in the event the defaulting Party in good faith contests such alleged default, the defaulting Party may give written notice of such contest to the other Parties within said sixty (60) calendar day period, and in such event, the Parties shall proceed to resolve the dispute in as provided in Section 9.3. The Parties shall continue performance of this COSG Agreement during the pendency of any such dispute resolution proceeding. If the dispute resolution process determines that the alleged default occurred, the defaulting Party shall have fifteen (15) calendar days after the date of such to begin good-faith curative action.

Section 9.3 Dispute Resolution.

(i) Panel of Senior Executives. Each Party shall select a senior executive with authority to decide or resolve the matter in dispute. Such senior executives shall meet and in good faith attempt to resolve the dispute within thirty (30) calendar days. If the Parties are unable to resolve the dispute pursuant to this Section 9.3(i), any Party may enforce its rights pursuant to Section 9.3(ii).

(ii) Arbitration. If any Party alleges that there is a default by the other Party of its obligations under this COSG Agreement, such dispute shall be finally resolved by arbitration in Rapid City, South Dakota before one (1) arbitrator. The Parties shall request that an arbitrator be provided who has experience with the resolution of disputes related to the acquisition and development of oil and gas properties as the matter may require. The arbitration shall be administered by JAMS pursuant to its Comprehensive Arbitration Rules and Procedures. Judgment on the award may be entered in any court having jurisdiction. This clause shall not preclude the Parties from seeking provisional remedies in aid of arbitration from a court of appropriate jurisdiction. The Parties shall equally share the costs of the arbitration proceeding and shall otherwise each pay their own costs related to the arbitration, including attorneys' fees and expert witness costs, *provided* that the arbitrator shall have authority to assess the costs of the arbitration proceeding, as well the prevailing Party's costs, including attorneys' fees and expert witness costs, against the non-prevailing Party as part of the award. The Parties shall be legally bound by the arbitrator's decision and agree that review of the arbitrator's decision shall be limited to those grounds specified in the Federal Arbitration Act. If any Party fails to proceed with arbitration, fails to comply with the decision, or unsuccessfully challenges the decision, that Party must pay all of the other Party's costs of suit including reasonable attorneys' fees and expert witness costs incurred to enforce or defend such a decision.

Section 9.4 Force Majeure. If BHUH is rendered unable, wholly or in part, by a Force Majeure Event to carry out its obligations under this COSG Agreement, other than the obligations to make monetary payments, or if a Force Majeure Event renders COSGCO unable, wholly or in part, to perform BHUH's directives, then BHUH shall give the Utilities prompt written notice describing the Force Majeure Event in reasonable detail. Thereupon, the obligations of BHUH, so far as it is affected by the Force Majeure Event, shall be suspended for a period equal to the period of the continuance of the Force Majeure Event. BHUH shall itself, or shall cause COSGCO to, use all reasonable diligence to remove the Force Majeure Event as quickly as practicable. The requirement that any Force Majeure Event be remedied with all reasonable dispatch shall not require the settlement of strikes, lockouts or other labor difficulty by the Party affected, contrary to its wishes, and settlement or resolution of such matters shall be within the discretion of the affected Party. "**Force Majeure Event**" shall mean an act of God, act of terrorism, strike, lockout, or other industrial disturbance, act of the public enemy, war (declared or undeclared), blockade, public riot, landslide, lightning, fire, storm, storm warning that results in evacuation of the affected area, flood, washout, maintenance, integrity testing, breakage, blockage, accidents to or freezing of oil and gas production, processing or transportation equipment, explosion, governmental action, restraint or inaction, the interruption or suspension of the receipt or delivery of Gas due to the inability or failure of any third party not a Party to this COSG Agreement to receive or deliver such Gas, unavailability of equipment, or inability to gain access, ingress or egress to conduct operations (including delays in or inability to obtain permits, approvals or clearances, which includes permits or approvals related to the use of any specific fracture stimulation technology or methodology, from any governmental authority), and any other factor or circumstance beyond BHUH or COSGCO's control, whether foreseen, foreseeable or unforeseeable, that limits, delays or prevents either BHUH's performance of this COSG Agreement or COSGCO's production, processing, and/or sale of Hydrocarbons from the Properties and that could not have avoided by the exercise of due diligence. For the avoidance of doubt, if a Force Majeure Event prevents COSGCO from selling Hydrocarbons on the market to third parties, the Parties' respective rights and obligations under ARTICLE 5 shall not be suspended.

Section 9.5 Assignment. No Party may assign or transfer, by assignment, sale, merger or otherwise by operation of law, in whole or in part, any of its rights or obligations under this COSG Agreement without the prior written consent of the other Parties, which may be withheld by each in its sole discretion, and any attempted assignment or transfer without such prior written consent shall be void, *provided* that (i) this Section 9.5 shall not apply to a change of control in BHUH or a sale of substantially all of BHUH's assets to a third party, and (ii) if BHUH does not consent, then the PUC for the Utility seeking to assign or transfer shall be deemed to have ordered that Utility to terminate its rights and obligations under the COSG Agreement pursuant to Section 6.2.

Section 9.6 Notices. All notices and communications required or permitted under this COSG Agreement shall be in writing addressed as indicated below, and any communication or delivery made pursuant to this Section 9.6 shall be deemed to have been duly delivered and received upon the earliest of: (i) actual receipt by the Party to be notified; (ii) three (3) calendar days after deposit with the U.S. Postal Service, certified mail, postage prepaid, return receipt requested; or (iii) two (2) calendar days after deposit with Federal Express overnight delivery (or other reputable overnight delivery service), postage prepaid, return receipt requested. Addresses for all such notices and communication shall be as follows:

To BHUH:

Black Hills Utility Holdings, Inc.
c/a Black Hills Corporation
625 Ninth Street
Rapid City , SD 57701
ATTN: President

With a copy to:

Patrick Joyce
Senior Managing Counsel
Black Hills Corporation
1102 E. 1st Street
Papillion, NE 68046
Fax: 402-829-2691

To Utilities:

Black Hills Power, Inc.
409 Deadwood Avenue
Rapid City, SD 57702
ATTN: President

Black Hills/Colorado Electric Utility Company, LP
105 South Victoria
Pueblo, CO 81003
ATTN: President

Black Hills/Colorado Gas Utility Company, LP
7060 Alegre Street
Fountain, CO 80817
ATTN: President

Black Hills/Iowa Gas Utility Company, LLC
1701 48th Street # 260
West Des Moines, IA 50266
ATTN: President

Black Hills/Kansas Gas Utility Company, LLC
110 East 9th Street
Lawrence, KS 66044
ATTN: President

Black Hills/Nebraska Gas Utility Company, LLC
501 West 6th Street
Papillion, NE 68046
ATTN: President

Black Hills Northwest Wyoming Gas Utility Company, LLC
1301 West 24th Street
Cheyenne, WY 82001
ATTN: President

Cheyenne Light, Fuel & Power
1301 West 24th Street
Cheyenne, WY 82001
ATTN: President

With a copy to (regardless of the receiving Utility):

Patrick Joyce
Senior Managing Counsel
Black Hills Corporation
1102 East 1st Street
Papillion, NE 68046
Fax: 402-829-2691

Each Party may, upon written notice to the other Parties, change the address and person to whom such communications are to be directed.

Section 9.7 Relationship of the Parties. This COSG Agreement is not intended to create, and shall not be construed to create, an association for profit, a trust, a joint venture, a mining partnership or other relationship of partnership, or entity of any kind between the Parties. The Parties understand and agree that the liabilities of the Parties shall be several, not joint or collective and that each Party shall be solely responsible for its own obligations except as otherwise provided in this COSG Agreement.

Section 9.8 No Third-Party Beneficiary. This COSG Agreement is made solely for the benefit of the Parties and their permitted successors and assigns, and no other person shall have any right, benefit or interest under or because of this COSG Agreement. There are no intended third-party beneficiaries of this COSG Agreement.

Section 9.9 Entire Agreement. This COSG Agreement and the exhibits to this COSG Agreement contain the entire agreement of the Parties with respect to the subject matter of this COSG Agreement and supersede all previous agreements or communications between the Parties, verbal or written, with respect to the subject matter of this COSG Agreement.

Section 9.10 Governing Law. This COSG Agreement shall be governed by and construed and interpreted in accordance with the laws of the State of South Dakota, without reference to its conflict of law provisions.

Section 9.11 Amendments; Waiver. No amendments or other modifications or changes to this COSG Agreement shall be effective or binding on any Party unless the same shall be in a writing executed by all Parties, *provided* that BHUH may agree to another utility(ies) becoming a party(ies) to this COSG Agreement, without a writing being executed by the Utilities and approved by their PUCs, but subject to the following limitations: (i) the terms and conditions to which the Utilities are bound under the COSG Agreement shall remain the same; and (ii) any such added utility shall be deemed a Non-Participating Utility with respect to any Property approved pursuant to Section 4.3 before such utility becomes a party to this COSG Agreement. No waiver by any Party of any one or more defaults by the other in the performance of this COSG Agreement shall operate or be construed as a waiver of any future default or defaults, whether of a like or different nature.

Section 9.12 Public Announcements. Unless otherwise agreed or required by law as determined by a Party, a Party may make any public announcement or statement with respect to this COSG Agreement or the transactions contemplated by this COSG Agreement without the consent of the other Parties, *provided* that the non-announcing Parties shall be afforded an opportunity to review and comment upon any required public announcement or statement prior to the announcement or statement being made.

Section 9.13 Severability. If a court of competent jurisdiction determines that any clause or provision of this COSG Agreement is void, illegal, unenforceable or unconscionable under any present or future law (or interpretation thereof), the remainder of this COSG Agreement shall remain in full force and effect, and the clauses or provisions that are determined to be void, illegal, unenforceable or unconscionable shall be deemed severed from this COSG Agreement as if this COSG Agreement had been executed with the invalid provisions eliminated, *provided* that (i) upon any such determination, the Parties shall negotiate in good faith to modify this COSG Agreement so as to affect the original intent of the Parties as closely as possible, and (ii) if the removal of such provisions destroys the legitimate purposes of this COSG Agreement, then this COSG Agreement shall no longer be of any force or effect.

Section 9.14 Further Assurances. The Parties shall execute, acknowledge and deliver or cause to be executed, acknowledged and delivered such instruments and take such other action as may be necessary or advisable to carry out their obligations under this COSG Agreement and under any document or other instrument delivered pursuant to this COSG Agreement.

Section 9.15 Rules of Construction. The headings of the articles and sections of this COSG Agreement are for guidance and convenience of reference only and shall not limit or otherwise affect any of the terms or provisions of this COSG Agreement. All references in this COSG Agreement to articles, sections, subsections and other subdivisions refer to corresponding articles, sections, subsections and other subdivisions of this COSG Agreement unless expressly provided otherwise. Titles appearing at the beginning of any of such subdivisions are for convenience only and shall not constitute part of such subdivisions and shall be disregarded in construing the language contained in such subdivisions. “Including” and its grammatical variations mean “including without limitation.” Unless the context otherwise requires, “or” is not exclusive; words in the singular form shall be construed to include the plural and vice versa; words in any gender include all other genders; references in this COSG Agreement to any instrument or agreement refer to such instrument or agreement as it may be from time to time amended or supplemented; and references in this COSG Agreement to any Party include such Party's permitted successors and assigns. All references in this COSG Agreement to exhibits refer to exhibits attached to this COSG Agreement unless expressly provided otherwise. This COSG Agreement has been drafted with the joint participation of BHUH and the Utilities and shall be construed neither against nor in favor of either one Party but in accordance with the fair meaning of its terms.

Section 9.16 Execution in Counterparts. This COSG Agreement may be executed by signing an original or a counterpart. If this COSG Agreement is executed in counterparts, all counterparts taken together shall have the same effect as if all the Parties had signed the same instrument.

Each Party caused this COSG Agreement to be executed, by its duly authorized representative, as of the day and year first above written.

BHUH:

Black Hills Utility Holdings, Inc.,
a South Dakota corporation

By: ______________________________
Name: ____________________________
Title: _____________________________

Utilities:

Black Hills Power, Inc.,
a South Dakota corporation

By: ______________________________
Name: ____________________________
Title: _____________________________

Black Hills/Colorado Electric Utility Company, LP,
a Delaware limited partnership

By: ______________________________
Name: ____________________________
Title: _____________________________

Black Hills/Colorado Gas Utility Company, LP,
a Delaware limited partnership

By: ______________________________
Name: ____________________________
Title: _____________________________

Black Hills/Iowa Gas Utility Company, LLC,
a Delaware limited liability company

By: ______________________________
Name: ____________________________
Title: _____________________________

Black Hills/Kansas Gas Utility Company, LLC,
a Delaware limited liability company

By: ______________________________
Name: ____________________________
Title: _____________________________

Black Hills/Nebraska Gas Utility Company, LLC,
a Delaware limited liability company

By: ______________________________
Name: ____________________________
Title: _____________________________

Black Hills Northwest Wyoming Gas Utility Company, LLC,
a Delaware limited partnership

By: ______________________________
Name: ____________________________
Title: _____________________________

Cheyenne Light, Fuel and Power Company,
a Wyoming corporation

By: ______________________________
Name: ____________________________
Title: _____________________________

EXHIBIT A

Acquisition Criteria

1. A Property must have:

   a. On a net present value basis (in nominal dollars using the then-applicable Cost of Capital as the discount rate), a COSG Cost Forecast for the term of its Reserve Report that is less than the then-current Long-Term Market Price Forecast of Gas prices for the same volumes over the same period, so that it is reasonably anticipated, based on then-available information, that its acquisition and development pursuant to the Proposed Drilling Program will generate a savings for the Utilities' customers;

   b. Proved developed producing reserves equal to at least fifty percent (50%) of the net present value of the acquisition by COSGCO (using the then-applicable Cost of Capital as the discount rate), but this criterion shall not apply if COSGCO is to earn interests in the Property through drilling;

   c. An expected remaining producing life of at least fifteen (15) years; and

   d. At least fifty percent (50%), on a btu basis, of its anticipated Hydrocarbon production consist of Gas.

2. A Property must be located:

   a. In the Rockies or Mid-continent regions of the United States and must contain formations with (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; and

   b. At or near trading hub locations to minimize costs to transport Gas to market.

3. If the Property is to be acquired from, or operated by, Black Hills Exploration and Production, Inc. or any other affiliate of Black Hills Corporation, then an independent third party must have issued a valuation opinion concluding the following:

   a. COSGCO's proposed transaction with that affiliate is fair based on other deals with unrelated third parties that are known in the market; and

   b. The terms of any agreements to which COSGCO would become a party through the transaction with that affiliate are commercially reasonable.

EXHIBIT B

Drilling Plan Criterion

The wells to be developed under the updated Drilling Plan before the next Five-Year Anniversary must have on a net present value basis (in nominal dollars using the then-applicable Cost of Capital as the discount rate) a COSG Cost Forecast for their producing life as determined by the Reserve Report that is less than the then-current Long-Term Market Price Forecast for Gas for the same volumes over the same period, so that it is reasonably anticipated, based on then-available information, that developing these wells will generate a savings to the Utilities' customers.

EXHIBIT C

Percentage Share and Hedge Target

Each Utility's Hedge Target and Percentage Share for 2016 are as follows:

Utility	Current Annual Demand (in Dths)	Hedge Target (in Dths)	Percentage Share
Black Hills Power, Inc. (South Dakota and Wyoming only)	600,000	300,000	0.83%
Black Hills/Colorado Electric Utility Company, LP	10,500,000	5,250,000	14.46%
Black Hills/Colorado Gas Utility Company, LP	8,500,000	4,250,000	11.71%
Black Hills/Iowa Gas Utility Company, LLC	17,300,000	8,650,000	23.83%
Black Hills/Kansas Gas Utility Company, LLC	13,000,000	6,500,000	17.91%
Black Hills/Nebraska Gas Utility Company, LLC	16,200,000	8,100,000	22.31%
Black Hills Northwest Wyoming Gas Utility Company, LLC	1,400,000	700,000	1.93%
Cheyenne Light, Fuel and Power Company (gas)	4,700,000	2,350,000	6.47%
Cheyenne Light, Fuel and Power Company (elec.)	400,000	200,000	0.55%
Aggregate	*72,600,000*	*36,300,000*	*100%*

EXHIBIT D

Sample Hedge Credit Calculation

Line No.				
1	Per Section 5.1(i), the formula for calculating a Hedge Credit is as follows:			
2				
3	*Hedge Credit = -(Net Income-((Allowed ROE + 100 basis points) * Invested Equity)) * 1/(1-T)*			
4				
5	For example only, the following is how Section 5.1(i) would work in a hypothetical month:			
6			3,250,000	COSGCO Revenue from sales of Hydrocarbons
7				**COSGCO OpEx**
8			2,324,000	Operating Expenses
9			111,075	Interest Exp (40% of Investment Base)
10			814,925	Income Before Taxes
11			309,672	Ln 10 * 38% (Federal and State Income Taxes)
12		Net Income =	505,254	
13			1.61	Tax Gross up (1/(1-.38)
14		Hedge Credit	(166,366)	=-(ln12-((ln21+ln27)*ln25))*ln13
15				
16	Assumptions for the above calculation:			
17	Equity %		60.00%	
18	Allowed ROE		9.86%	
19	Debt %		40.00%	
20	Allowed Cost of Debt		4.50%	
21	Allowed ROE (monthly)	ln 18 ÷ 12	0.8217%	
22	Allowed Cost of Debt (monthly)	ln 20 ÷ 12	0.3750%	
23	Debt Expense (monthly)	ln 24 * ln 19 * ln 22	111,075	
24	Investment Base		74,050,000	
25	Invested Equity	ln 24 * ln 17	44,430,000	
26	100 Basis Points		1.00%	
27	100 Basis Points (monthly)	ln 26 ÷ 12	0.083%	
28	Actual ROE (monthly)	ln 12 ÷ ln 25	1.1372%	

Sample Hedge Cost Calculation

Line No.				
1	Per Section 5.1(ii), the formula for calculating a Hedge Cost is as follows:			
2				
3	*Hedge Cost = -(Net Income-((Allowed ROE - 100 basis points) * Invested Equity)) * 1/(1-T)*			
4				
5	For example only, the following is how Section 5.1(ii) would work in a hypothetical month:			
6			2,450,000	COSGCO Revenue from sales of Hydrocarbons
7				**COSGCO OpEx**
8			2,054,000	Operating Expenses
9			86,075	Interest Exp (40% of Investment Base)
10			309,925	Income Before Taxes
11			117,772	Ln 10 * 38% (Federal and State Taxes)
12	Net Income =		192,154	
13			1.61	Tax Gross up (1/(1-.38)
14	Hedge Cost		100,107	=-(ln12-((ln21-ln27)*ln25))*ln13
15				
16	Assumptions for the above calculation			
17	Equity %		60.00%	
18	Allowed ROE		9.86%	
19	Debt %		40.00%	
20	Allowed Cost of Debt		4.50%	
21	Allowed ROE (monthly)	ln 18 ÷ 12	0.8217%	
22	Allowed Cost of Debt (monthly)	ln 20 ÷ 12	0.3750%	
23	Debt Expense (monthly)	ln 24 * ln 19 * ln 22	86,075	
24	Investment Base		57,383,333	
25	Invested Equity	ln 24 * ln 17	34,430,000	
26	100 Basis Points		1.00%	
27	100 Basis Points (monthly)	ln 26 ÷ 12	0.083%	
28	Actual ROE (monthly)	ln 12 ÷ ln 25	0.5581%	

Public Version Exhibit IV-2 -Percentages of Gas Supply Purchases by Type_

EXHIBIT IV-2

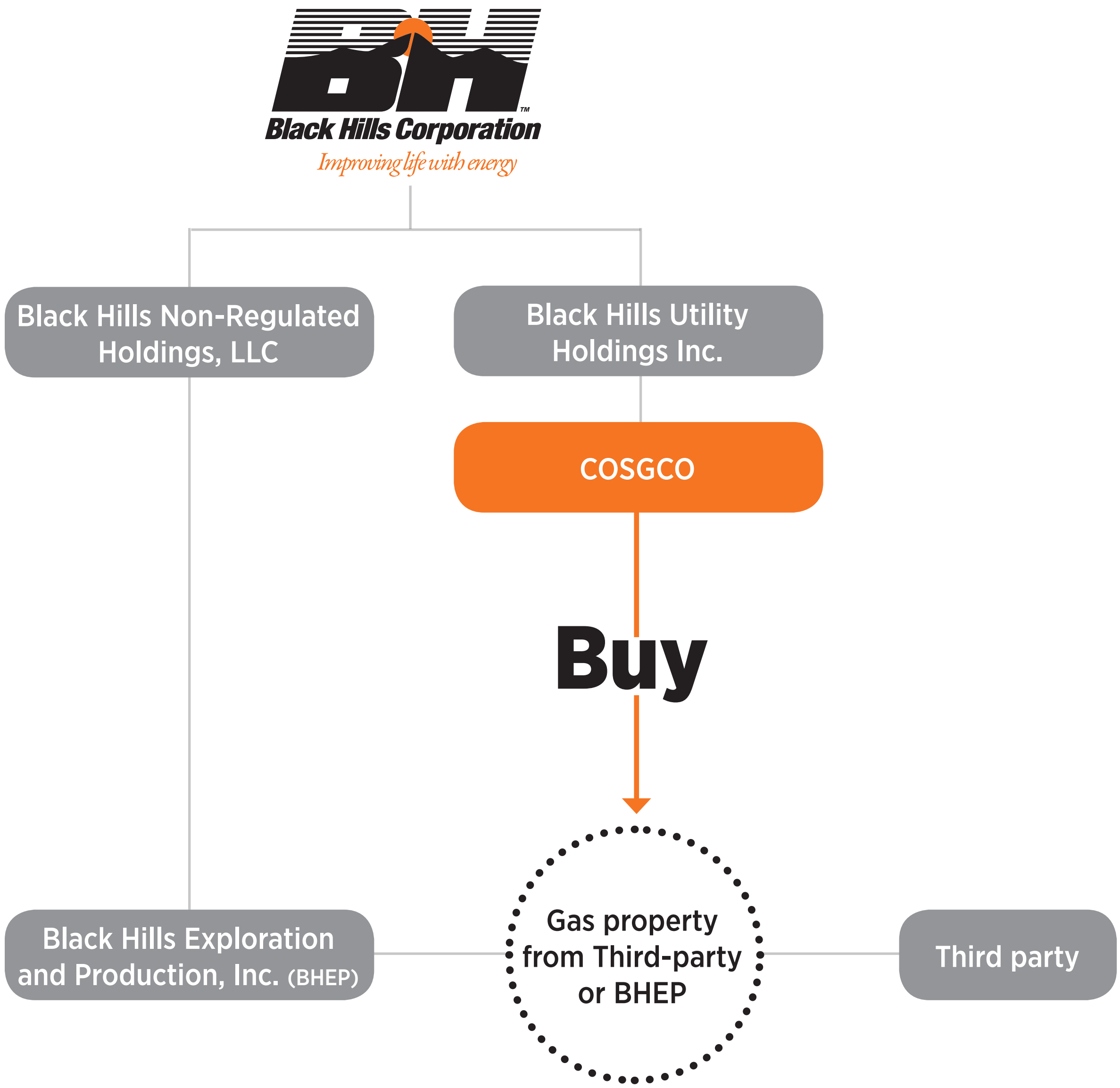
[redacted]							
[redacted]			[redacted]	[redacted]			
		[redacted]	[redacted]		[redacted]		
		[redacted]			[redacted]	[redacted]	
[redacted]							
	[redacted]			[redacted]	[redacted]	[redacted]	[redacted]
	[redacted]			[redacted]	[redacted]	[redacted]	[redacted]
	[redacted]			[redacted]	[redacted]	[redacted]	[redacted]
	[redacted]			[redacted]	[redacted]	[redacted]	[redacted]
	[redacted]			[redacted]	[redacted]	[redacted]	[redacted]
	[redacted]			[redacted]	[redacted]	[redacted]	
	[redacted]	[redacted]				[redacted]	[redacted]
	[redacted]						

COSG Term Sheet

Exhibit IV-3 -Summary of financial and operational terms

Term; Drilling Plan	1. Life of wells acquired or drilled on the properties, through abandonment and reclamation for each well. 2. Drilling plan for the properties – 20–years seeking stable levels of production to track utilities' needs, re-approved prospectively in years 5, 10 & 15 with option to extend in year 20.
Target % Of Firm Demand	Up to 50% of weather normalized annual firm demand depending on availability of suitable properties.
Future Producing Property or Drilling Property Acquisition	Based on commission approved guidelines established when program is approved.
Recovery Mechanism	In accordance with existing adjustment clauses (PGA/ECA).
Independent Oversight	Third-Party hydrocarbon and accounting monitors; costs to be paid through program; assessing in advance each Property purchase and proposed drilling program; audit of reports for accuracy.
BHUH Revenue Requirement for Hedge Quantity of Gas	COSGCO operating expenses for properties (including overhead costs paid to field operator, O&M, gathering, processing and marketing costs, tax and royalty payments)+(ROI * Invested Capital). All invested capital is non-utility capital.
Hedge Performance and Risk Sharing	If the cost of service gas revenue requirement is less than COSGCO market sales proceeds, BHUH will keep the difference up to an equivalent of 100 basis points of additional ROE and after that, the excess will be credited to customers. If the cost of service gas revenue requirement is more than COSGCO market sales proceeds, BHUH will absorb the difference up to an equivalent of 100 basis points of additional ROE and after that, the excess will be charged to customers.
Cost of Debt	Weighted average of Black Hills Corporation cost of LT debt and cost of LT debt, if any, issued at Newco.
Allowed Return	Authorized ROE = Annual average of all gas and electric utility rate case ROE's as reported by Regulatory Research Associates for the previous calendar year, adjusted the month following report availability. If less than 20 in a calendar year, then average ROE of most recent 20 cases.
Capital Structure	40% Debt / 60% Equity (Blend of utility and E&P industry capital structure).

A Potential Structures for COSGCO's Acquisition/Development Deals



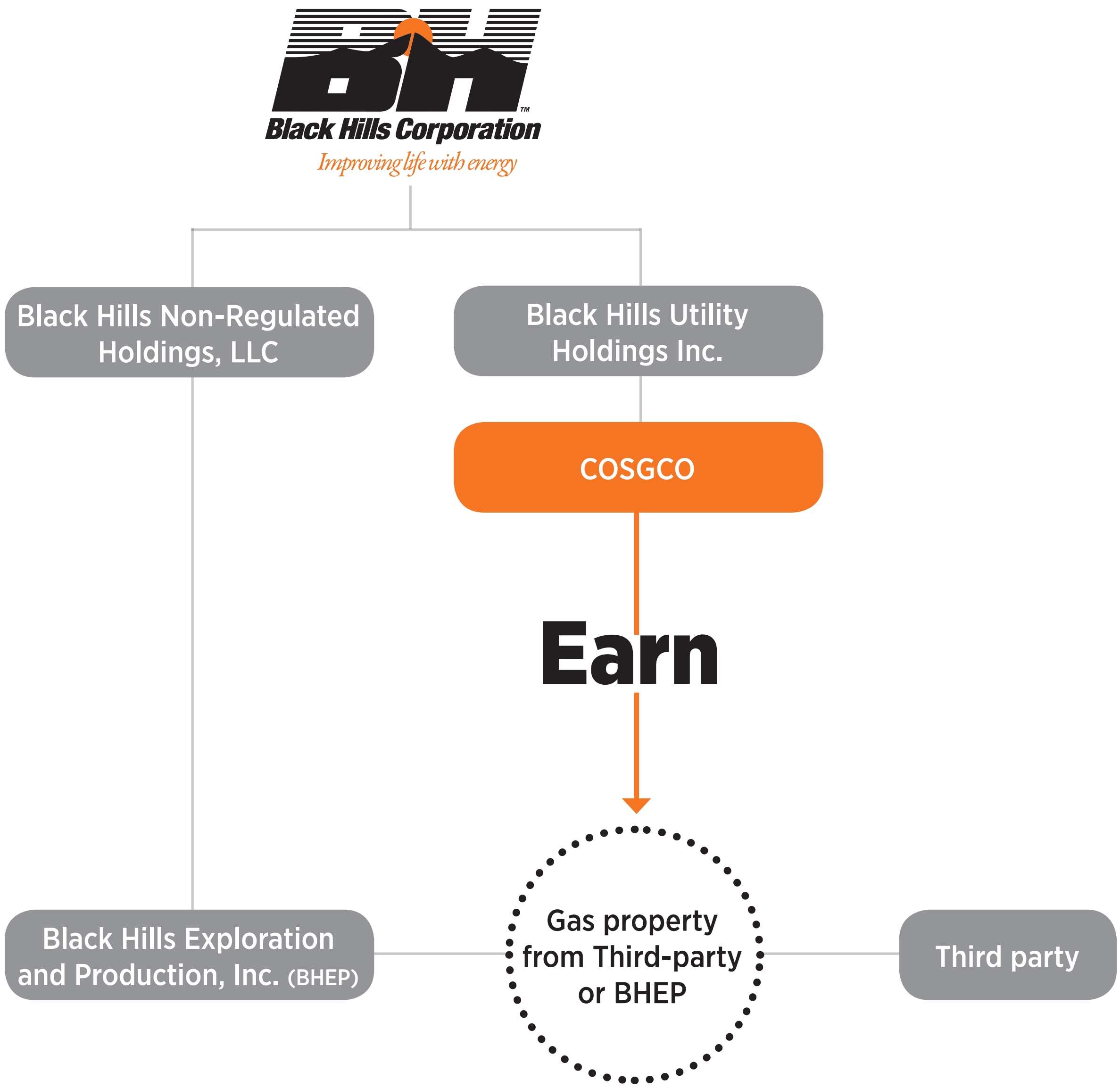
COSGCO buys interest in gas property either from a third party or from BHEP.

COSGCO could buy interests in both existing wells and new drilling locations.

BHEP or third party would be operator for COSGCO

Exhibit IV-4 -Diagram of Possible Structures for COSG Program

B Potential Structures for COSGCO's Acquisition/Development Deals



COSGCO earns interests by funding drilling of new wells.

COSGCO could earn interests in both existing wells and new wells.

Earning interests has tax advantages for ratepayers.

BHEP or third party would be operator for COSGCO