

EXHIBIT 4  
Direct Testimony and Exhibits  
JOHN BENTON

BEFORE THE PUBLIC UTILITIES COMMISSION  
OF THE STATE OF SOUTH DAKOTA

In the Matter of the Application of Black Hills Power, Inc.

To Approve Tariff Revisions Related to Its Cost of Service  
Gas Agreement With Black Hills Utility Holdings, Inc.

Docket No. EL 15 –\_\_

September 30, 2015

## TABLE OF CONTENTS

I.	INTRODUCTION AND QUALIFICATIONS .....	1
II.	PURPOSE OF TESTIMONY .....	2
III.	GENERAL OVERVIEW OF THE GAS EXPLORATION AND PRODUCTION INDUSTRY .....	3
IV.	BHEP’s ROLE IN THE COSG PROGRAM AND ITS BACKGROUND, EXPERIENCE AND EXPERTISE .....	22
V.	CONCLUSION .....	27

### Exhibits

Exhibit 4.1	Well design diagram
Exhibit 4.2	Sample production decline curves
Exhibit 4.3	Sample joint operating agreement

1                                   **I.       INTRODUCTION AND QUALIFICATIONS**

2   **Q.     PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.**

3   A.     John H. Benton, 1515 Wynkoop Street, Suite 500, Denver, CO 80202.

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

5   A.     I am Vice President and General Manager, Black Hills Exploration and  
6           Production, Inc. (“BHEP”), the oil and gas exploration and production subsidiary  
7           of Black Hills Corporation. I am responsible for managing BHEP’s existing  
8           producing assets as well as identifying, acquiring, appraising, and developing new  
9           oil and gas opportunities to add to BHEP’s portfolio. I have overall responsibility  
10          for geology, engineering, accounting, permitting, regulatory compliance, safety,  
11          and field operations.

12 **Q.     FOR WHOM ARE YOU TESTIFYING?**

13 A.     I am testifying on behalf of Black Hills Power, Inc. (the “Company”).

14 **Q.     PLEASE DESCRIBE YOUR EDUCATIONAL AND BUSINESS**  
15 **BACKGROUND.**

16 A.     I received a Bachelor’s Degree and Master’s Degree in Petroleum Engineering  
17          from the Colorado School of Mines. I have more than 35 years of experience  
18          working on operations and reservoir engineering projects throughout North  
19          America, Europe, South America and Indonesia. I have served in leadership  
20          positions with Rex Energy, El Paso Exploration & Production, Whiting Petroleum  
21          Corporation, Calver Resources, Conoco Canada, Gulf Canada Resources Limited,

1 and Westport Oil and Gas. Immediately prior to joining BHEP in 2011, I served  
2 as Vice President and General Manager of Rex Energy's Rockies Division and  
3 was responsible for developing its Niobrara Shale assets in Wyoming and  
4 Colorado. While at BHEP I have focused on developing our Mancos Shale gas  
5 assets in Colorado and northwest New Mexico and developing new oil and gas  
6 opportunities. I am a member of the Society of Petroleum Engineers (SPE) and  
7 the Society of Petroleum Evaluation Engineers (SPEE). Since my appointment in  
8 2011 by Colorado Governor John Hickenlooper, I have served as a Commissioner  
9 with the Colorado Oil and Gas Conservation Commission, which is responsible for  
10 regulating oil and gas exploration and production activities in Colorado.

11 **Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THIS COMMISSION?**

12 A. No.

13 **II. PURPOSE OF TESTIMONY**

14 **Q. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY?**

15 A. My testimony will describe (i) the oil and gas exploration and production business,  
16 including common structures for acquiring the right to drill wells and produce gas  
17 and the typical costs incurred in drilling and operating wells; and (ii) BHEP's role  
18 in the Cost of Service Gas Program ("COSG Program") and its qualifications for  
19 that role, including its experience and expertise in acquiring and developing shale  
20 gas resources, and record of environmental compliance and cost management.

1                   **III.    GENERAL OVERVIEW OF THE GAS EXPLORATION**  
2   **AND PRODUCTION INDUSTRY**

3   **Q.    PLEASE PROVIDE A GENERAL OVERVIEW OF THE EXPLORATION**  
4   **AND PRODUCTION INDUSTRY IN THE UNITED STATES?**

5   A.   Oil and gas producers typically obtain the right to explore and produce oil and gas  
6       on a particular property (called a “working interest” by the industry) through an oil  
7       and gas lease from whomever owns the mineral rights in that property.  The  
8       mineral owner may be a private person or a government, and because mineral  
9       rights can be sold separately, the mineral owner and the “surface” owner may be  
10      different.  The lease gives the producer the exclusive right to explore, drill,  
11      produce and sell the oil and gas on the property with the mineral owner being paid  
12      a royalty on oil and gas produced from the property.

13      Oil and gas are slowly formed from organic matter trapped in sedimentary rock,  
14      buried at great depths by geologic processes, and heated by the earth.  Much of the  
15      oil and gas is formed in black, organic rich mudstones or shales, referred to as  
16      “source rocks.”  Historically, “conventional” oil and gas production has been from  
17      vertical wellbores drilled into folds and faults in the rock formations that  
18      geologists have identified as being possible traps for oil and gas slowly migrating  
19      from the source rocks through the sedimentary layers.  Knowing where to drill was  
20      a very difficult challenge in the early days of the industry.  Eventually,  
21      sophisticated geology and geophysics techniques were developed to increase the

1 chances of finding rich concentrations or “pools” of oil and/or gas, usually trapped  
2 by arches or faults in the rock formations that were at most a few miles across.  
3 Even with these advances, the success rate for exploration wells in conventional  
4 resources is approximately 1 in 5. After an arch or fault containing oil and/or gas  
5 is discovered, development wells are drilled in that arch or fault. Development  
6 wells have a success rate of about 8 in 10, and once the oil and/or gas trapped in  
7 that arch or fault has been produced, the wells are plugged and abandoned. To  
8 maintain or grow production levels, exploration for a similar structure is required  
9 to find new oil and gas reserves.

10 Over the last 10 years, the combination of two established technologies –  
11 horizontal drilling and hydraulic fracturing – has revolutionized the oil and gas  
12 industry, allowing the development of enormous new shale or tight gas resources  
13 (also known as “unconventional” resources), such as the Marcellus Shale that lies  
14 beneath large parts of several northeastern states. Geologists have long known  
15 that certain shales were source rocks from which the oil and gas had never left due  
16 to shale’s very low permeability. Tight gas resources consist of fine sand or silt  
17 formations that, like shale formations, have very low permeability. Traditional  
18 vertical-well completion techniques were not viable because the lack of  
19 permeability meant the oil and gas could not flow to the well. Horizontal drilling  
20 exposes thousands of feet of low-permeability rock to the well, and hydraulic

1 fracturing increases the permeability of the rock near the well, allowing profitable  
2 development of these resources.

3 Unlike conventional resources, which require discovery of localized underground  
4 folds and faults that trap oil and gas, shale or tight gas resources tend to be  
5 productive over tens or even hundreds of miles. As a result, nearly all wells now  
6 drilled in shale or tight gas resources are successful in terms of finding oil or gas.  
7 (Sometimes there may be a mechanical or technical problem drilling a well or  
8 maintaining production from a well that ultimately means the well does not  
9 produce as anticipated.) A horizontal shale well may also produce, in many cases,  
10 significantly more oil and gas than a conventional vertical well. The end result is  
11 lower risk and lower costs to develop shale or tight gas resources on a unit of gas  
12 basis.

13 A variety of relatively recent technological and management improvements have  
14 enabled the industry to more efficiently develop shale or tight gas resources,  
15 which in turn has helped to further lower the costs of developing these resources.  
16 The U.S. Energy Information Agency's ("EIA") February 2013 Short-Term  
17 Energy Outlook Supplement summarizes these improvements, such as multi-well  
18 drilling pads and "walking" drill rigs. Improvements in drill bit and drilling fluids  
19 design have also significantly increased drilling penetration rates, which have  
20 increased the productivity of drilling rigs by increasing the number of wells that  
21 one rig can drill in a year, a key metric for drilling efficiency. These

1 improvements continue as the EIA's August 2015 Drilling Productivity Report for  
2 key shale resources shows that new production per rig continues to increase. As  
3 Figure 2 in Julia Ryan's direct testimony illustrates, the EIA projects that the vast  
4 majority of gas produced in the United States in coming decades will be from  
5 shale or tight gas resources.

6 **Q. PLEASE BRIEFLY DESCRIBE THE PROCESS OF HYDRAULIC**  
7 **FRACTURING.**

8 A. Hydraulic fracturing (or fracking) is the process of pumping mostly water and  
9 sand (together comprising 98% to 99.5% of the hydraulic fracturing fluid  
10 depending upon the target formation) and other ingredients at high pressure into  
11 formations that have been drilled for oil and gas production. The pressure of the  
12 fluids creates fissures in the rock increasing the formation's permeability. The  
13 sand (called "proppant" by the industry) keeps the fissures open when the pressure  
14 and hydraulic fracturing fluid is removed, allowing previously trapped oil and gas  
15 to flow to the wellbore and be extracted. While some believe hydraulic fracturing  
16 is a new practice, it has actually been safely conducted for 65 years on more than  
17 1.2 million wells.

18 **Q. DOES HYDRAULIC FRACTURING PRESENT MATERIAL**  
19 **OPERATIONAL OR ENVIRONMENTAL RISKS?**

20 A. Like almost every human endeavor, there are risks, but producers and regulators  
21 have done an excellent job assessing and avoiding these risks. Hydraulic



1 fracturing has been done safely for decades, and technological advances and  
2 regulatory oversight has kept pace with the development of the technology. The  
3 key to risk mitigation is proper well construction, because fresh water resources  
4 could be impacted if the integrity of the well is compromised during hydraulic  
5 fracturing. Drilling permits require wellbore construction that protects fresh water  
6 zones from potential contamination by hydraulic fracturing fluids. Producers  
7 design and construct the wells to handle the flow rates and pressures associated  
8 with hydraulic fracturing. This usually includes multiple strings of steel pipe,  
9 which is called casing, cemented in place to protect the formations above the  
10 producing formation. Attached as Exhibit 4.1 is a simple diagram showing a well  
11 design for hydraulic fracturing. In June, 2015, the U.S. Environmental Protection  
12 Agency (“EPA”) released its long-awaited, draft assessment of the potential  
13 impacts to drinking water resources from hydraulic fracturing. The assessment  
14 recognized that there are mechanisms by which hydraulic fracturing could impact  
15 drinking water resources, but “did not find evidence that these mechanisms have  
16 led to widespread, systemic impacts on drinking water resources in the United  
17 States.”

1 **Q. PLEASE COMMENT ON THE EPA'S RECENTLY PROPOSED RULES**  
2 **REGARDING METHANE EMISSIONS FROM OIL AND GAS**  
3 **PRODUCTION.**

4 A. The EPA proposed rules in August 2015 concerning methane emissions from oil  
5 and gas production, including from new wells that are hydraulically fractured.  
6 The goal is to reduce methane emissions from oil and gas production by 40%-45%  
7 over the next decade, compared to 2012 levels.

8 The state of Colorado adopted similar rules in February 2014 which in some areas  
9 are more stringent than EPA's proposed rules. For example, Colorado's rule  
10 applies to both existing and new sources while EPA's proposed rule only applies  
11 to new sources. In addition, the frequency of leak detection under Colorado's  
12 rules is determined by volume of flow and emissions and can be as frequent as a  
13 quarterly basis. In contrast, EPA's proposed rule calls for semi-annual inspections  
14 and provides an opportunity to reduce to even a less frequent schedule. Some  
15 operators, such as BHEP, already utilize operations and compliance standards that  
16 meet or exceed EPA's proposed requirements.

17 Under EPA's proposed rule, it may be necessary in certain circumstances to obtain  
18 a major source air permit under the Clean Air Act. Although additional time may  
19 be needed to obtain these permits, the operating and emission requirements would  
20 not be significantly different.

1 **Q. PLEASE SUMMARIZE TYPICAL CAPITAL COSTS THAT ARE**  
2 **INCURRED WHEN DRILLING A WELL.**

3 A. There are the following three major capital cost categories when drilling a well:

4 1. Drilling costs, which include permitting, location construction, drilling rig,  
5 drilling tools (including bits), directional services, drilling fluids, logging,  
6 casing, cementing, and well-site supervision;

7 2. Completion costs, which include production casing, cement, completion  
8 rig, perforating, stimulation (e.g., hydraulic fracturing), equipment rentals,  
9 tubing, wellhead, and well-site supervision; and

10 3. Tie in costs, which are the costs to connect the well to the gathering system  
11 and include (depending on the components of the production stream from  
12 the well) free-water knockouts, separators, heater treaters, line heaters,  
13 lease flow lines, meters, various pumps, and tanks.

14 The costs to develop a well depend upon many factors and differ from field to  
15 field.

16 **Q. WHAT IS GAS GATHERING AND GAS PROCESSING?**

17 A. Gas gathering and gas processing occur between the well and the interstate  
18 pipeline system. The gas gathering system is a collection of pipelines (known as  
19 gathering lines) within the field that transport gas from wells to a processing  
20 facility, which is connected to an interstate pipeline. Before gas enters the  
21 gathering system, oil that condenses out of the gas stream (i.e., condensate) and

1 water are removed. The condensate is then sold. Other substances, such as carbon  
2 dioxide and natural gas liquids (e.g. propane), are removed at the processing  
3 facility (gas plant) so that the gas meets interstate pipeline quality specifications.

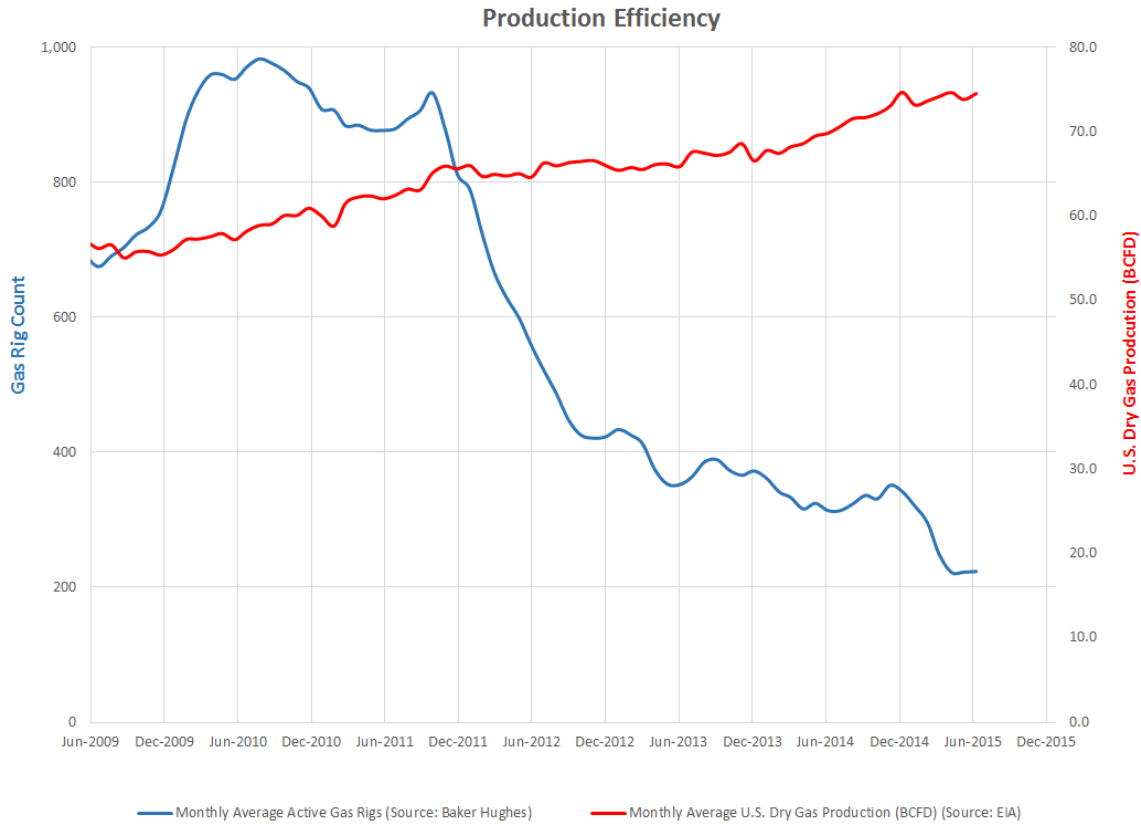
4 Gathering systems and processing plants may be owned by the working interest  
5 owners, but are often developed and owned by third parties. Working interest  
6 owners in the wells commit to deliver gas produced from certain properties to the  
7 gathering system and processing facility. The owner of the gathering system is  
8 paid a fee to compress and move the gas through the system to the processing  
9 facility. The owner of the processing facility may be paid a fee or receive part or  
10 all of the natural gas liquids as compensation. If the working interest owners  
11 retain any of the natural gas liquids, those are sold.

12 **Q. PLEASE SUMMARIZE THE TYPICAL KINDS OF COSTS THAT ARE**  
13 **INCURRED IN OPERATING A WELL.**

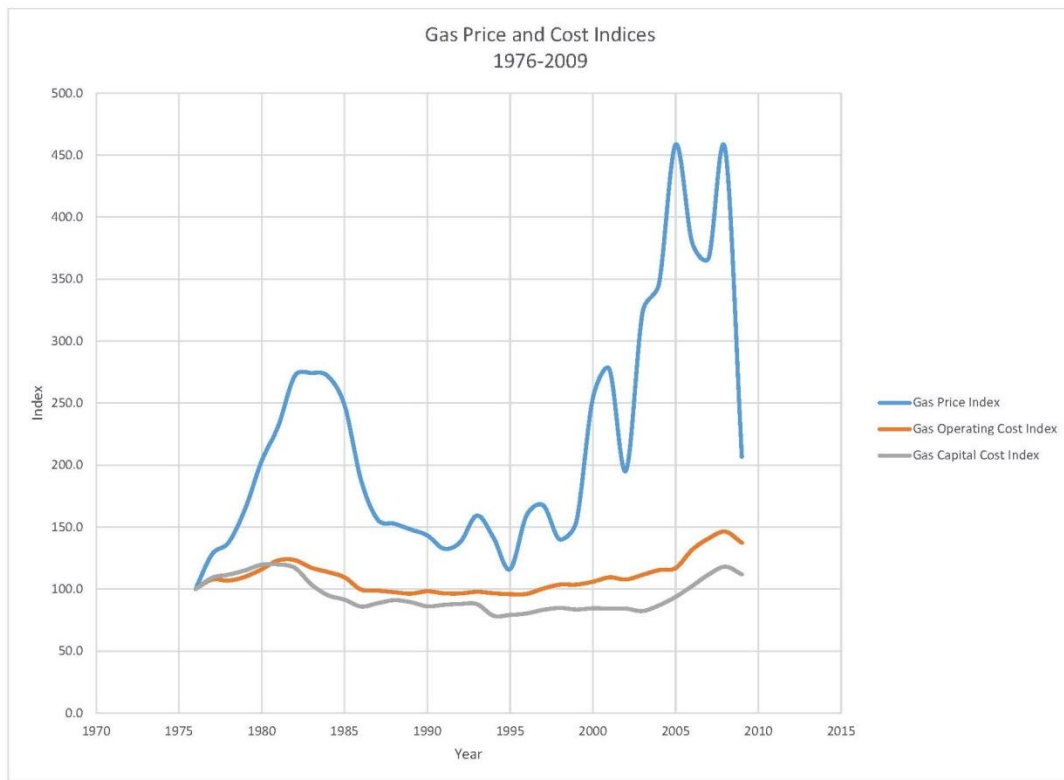
14 A. Well operating costs can include royalty payments to mineral rights owners, well  
15 supervision, transportation, utilities, water disposal, surface equipment  
16 maintenance and repair, subsurface workovers and repairs, gas measurement,  
17 gathering and processing, production taxes, chemicals, environmental and  
18 regulatory compliance, location maintenance, and operator labor and overhead  
19 costs.

1 **Q. ARE THE COSTS OF DRILLING AND OPERATING A WELL**  
2 **RELATIVELY PREDICTABLE AND STABLE?**

3 A. Yes. Although the costs to develop and operate wells differ to some extent from  
4 field to field, the costs within a field tend to be relatively predictable and stable.  
5 The biggest risk of fluctuation is in the cost of drilling wells, and the costs for  
6 drilling rigs and services can vary, especially in times of high demand. As  
7 producers gain more and more experience in a particular field, drilling becomes  
8 more and more efficient, which reduces the variability in development costs. The  
9 figure below, based on production data reported by the EIA and rig count data  
10 reported by Baker Hughes, illustrates drilling efficiencies realized for U.S. gas  
11 development in the last six years. Production continues to increase as the number  
12 of wells drilled per rig per year increases, which means less rigs are needed.



1            Operating costs tend to be relatively stable over the long-term particularly when  
 2            compared to the market price of gas. The figure below, based on numbers  
 3            reported by the EIA for operating costs from 1976 to 2009 (the last year such  
 4            information is available), demonstrates this.



1 **Q. HOW LONG WILL A GAS WELL CONTINUE TO PRODUCE?**

2 A. The typical life of a gas well depends upon field characteristics and operating  
 3 decisions, but on average a gas well will likely produce for over 20 years.  
 4 However, most of the production occurs in the first few years after the well is  
 5 drilled and the production naturally declines over time. For example, Exhibit 4.2  
 6 shows production decline curves for horizontal wells drilled in the Mancos and  
 7 Niobrara Shales in the Piceance Basin in western Colorado. Because well  
 8 production naturally declines with time, producers must continue to drill new  
 9 wells each year to maintain the same amount of production in a field.

1 **Q. HOW DOES A PRODUCER OBTAIN THE RIGHT TO PRODUCE**  
2 **NATURAL GAS FROM A PROPERTY?**

3 A. As noted above, a producer typically obtains the right to produce natural gas from  
4 a property (i.e., a working interest) through an oil and gas lease from the mineral  
5 owner. After a property is leased, the producer may sell 100% or some smaller  
6 percentage of its working interest to another producer for cash, just like other  
7 types of property transactions. In the alternative to a cash sale, producers may  
8 enter into a joint development agreement through which one producer agrees to  
9 pay for the cost to develop one or more new wells on the property in exchange for  
10 an agreed-to percentage of the other producer's working interest in the property.  
11 Both of these alternatives can involve existing producing wells, and both (or  
12 various combinations of the two) could be employed in the COSG Program.

13 **Q. PLEASE DESCRIBE A JOINT DEVELOPMENT AGREEMENT IN MORE**  
14 **DETAIL.**

15 A. Joint development agreements may cover multiple oil and gas leases and address  
16 how the parties will jointly develop the properties. These agreements are very  
17 flexible and can take many forms, including "farm-in" or "farm-out" agreements,  
18 drilling and development agreements, carry and earning agreements, and  
19 participation agreements. The producer owning the working interest (the  
20 "farmor") will agree to assign a percentage of its working interest to the other  
21 producer (the "farmee") in exchange for the farmee paying a disproportionate



1 share of the cost to develop one or more new wells on the property. There may be  
2 an upfront cash payment for existing reserves. Sometimes the farmee only earns  
3 an interest in the new well(s) drilled; in other deals the farmee also earns an  
4 interest in existing producing wells or undrilled leases. Sometimes the farmee  
5 drills the well(s); in other deals the farmor drills the well(s) using money from the  
6 farmee.

7 Many joint development agreements provide that the farmee will pay its own share  
8 of drilling costs plus a percentage of the farmor's drilling costs. Paying a portion  
9 of the farmor's drilling costs is referred to as a "carry." For example, the farmee  
10 might agree to pay 75% of the cost of drilling new wells in return for a 50%  
11 working interest. In such a case, the farmee is paying a 25% carry (*i.e.*, its 75%  
12 payment obligation minus the 50% working interest it will receive).

13 **Q. HAVE OTHER UTILITIES AGREED TO PAY A CARRY WHEN**  
14 **ACQUIRING GAS RESERVES THROUGH A JOINT DEVELOPMENT**  
15 **AGREEMENT?**

16 Yes. Northwest Natural Gas Company, an Oregon natural gas utility, agreed to  
17 pay a carry in its 2011 "Carry and Earning Agreement" with Encana Oil & Gas  
18 (USA), Inc. for the development of gas wells in Wyoming. Florida Power & Light  
19 Company also agreed to pay a carry in its 2014 agreement with PetroQuest  
20 Energy, Inc. for the development of gas wells in Oklahoma. Of course, utilities do  
21 not have to use joint development agreements to acquire gas reserves. Earlier this

1 year, Washington Gas, a Virginia natural gas utility, agreed to simply pay cash for  
2 a large working interest in existing wells in Pennsylvania from Energy  
3 Corporation of America.

4 **Q. WHAT IS A JOINT OPERATING AGREEMENT?**

5 A. A joint operating agreement (“JOA”) provides the governing structure for the  
6 development and operation of jointly-owned oil and gas properties (e.g., selection  
7 of the “operator,” how decisions will be made and costs borne). There are  
8 standard industry JOA forms developed by the American Association of  
9 Professional Landmen. A sample JOA form, including the standard form  
10 accounting procedures (called the “COPAS” by the industry because it was  
11 developed by the Council of Petroleum Accountants Societies), is attached to my  
12 testimony as Exhibit 4.3. A form JOA is typically modified to address  
13 considerations specific to the particular property, working interest owners, and  
14 other factors to ensure the property is developed and managed appropriately. The  
15 working interest owner that is the “operator” under the JOA has the day-to-day  
16 operating responsibility and is obligated to act as a reasonable and prudent  
17 operator in accordance with good oilfield practice and in compliance with  
18 applicable laws, rules, and regulations. Each working interest owner bears its  
19 proportionate share of the operating costs. For example, if COSGCO were to have  
20 a 10% working interest in a property, it would bear 10% of the operating costs,

1 which the “operator” under the JOA would bill through joint interest billings in  
2 accordance with the COPAS.

3 **Q. ARE JOAS USED IN CONNECTION WITH JOINT DEVELOPMENT**  
4 **AGREEMENTS?**

5 A. Yes. Regardless of what form a joint development agreement might take, the  
6 parties will enter into a JOA.

7 **Q. WHAT KIND OF DUE DILIGENCE IS TYPICALLY INVOLVED WHEN**  
8 **ACQUIRING WORKING INTERESTS?**

9 A. Regardless of what structure an acquisition might take, due diligence typically  
10 involves (i) assessing the property’s reserves (e.g., obtaining a reserve report from  
11 a reservoir engineer), operating costs, drilling costs, and state of operations (e.g.,  
12 the condition of the property and facilities) and (ii) reviewing the selling working  
13 interest owner’s records, title to the assets, lease files, permits and material  
14 contracts (e.g., gathering and processing agreements, surface access agreements),  
15 and any pending or threatened litigation.

16 **Q. WHAT ARE THE KEY FACTORS THAT SHOULD BE CONSIDERED**  
17 **WHEN MAKING A GAS RESERVES INVESTMENT?**

18 A. The key factors are typically (i) the estimated amount of recoverable gas in the  
19 ground and the reasonable probability that amount can be recovered, (ii) the  
20 anticipated capital costs to further develop the reserves through drilling, (iii) the  
21 anticipated operating costs, and (iv) the forecast market price for gas over the life

1 of the reserves. The economics of investing in gas reserves can change if one or  
2 more of these factors materially increase or decrease from what was expected at  
3 the time of the acquisition (e.g., if the market price for natural gas decreases to an  
4 amount less than the cost to drill and produce from the property).

5 **Q. PLEASE EXPLAIN THE MEANING OF “PROVEN” RESERVES?**

6 A. There are three different categories of reserves—proven, probable, and possible—  
7 that reflect the reasonable probability of the gas being recovered given existing  
8 market, technologic, industry and regulatory conditions. Proven reserves have the  
9 greatest probability of being recovered. For example, the probability of recovering  
10 proved developed producing reserves—a subset of proven reserves—is generally  
11 90% or more. Under the COSG Program, COSGCO would acquire working  
12 interests in properties that have proven reserves. *See* Exhibit 3.1 (COSG  
13 Agreement, Ex. A, #1b).

14 **Q. PLEASE DESCRIBE PROVEN RESERVES IN MORE DETAIL.**

15 A. There are three subsets of proven reserves: (i) proved developed producing  
16 (“PDP”); (ii) proved developed non-producing (“PDNP”) or proved developed  
17 behind pipe (“PDBP”); and (iii) proved undeveloped (“PUD”). PDPs are proven  
18 reserves that an existing well can produce from geologic formations that are open  
19 for production (*i.e.*, the casing has been perforated so that gas can flow into the  
20 well and be brought to the surface). In some cases, an existing well may require

1 expenditures for equipment replacement or remedial workovers to recover the  
2 PDP reserves predicted from its historical performance.

3 PDNP/PDBP are proven reserves that can be produced from an existing well, but  
4 the well's casing has not yet been perforated in the formation containing those  
5 proven reserves. The probability of establishing production in the unperforated  
6 casing has to be established in an analogous and usually adjacent well.

7 PUDs are proven reserves that require capital investment to extract the oil or gas  
8 and bring it to the surface (e.g., drilling and completing a well). Using geologic  
9 and performance information from nearby producing wells, geologists and  
10 reservoir engineers can infer that it is reasonably certain that the gas will be  
11 recovered if PUDs are developed by drilling wells in these locations. With shale  
12 or tight gas resources, these experts are often able to identify many additional  
13 PUD locations based on experience with existing wells.

14 **Q. IS THERE A DIFFERENCE IN COST WHEN ACQUIRING PROVED**  
15 **DEVELOPED PRODUCING RESERVES VERSUS NON-PRODUCING**  
16 **PROVEN RESERVES?**

17 A. Yes. Producers acquiring reserves will pay a higher value for producing reserves  
18 (i.e., PDPs) compared to proven reserves that are not yet producing (i.e.,  
19 PDNPs/PDBPs and PUDs). There are two primary reasons for the difference in  
20 value. First, it costs money and takes time to develop the non-producing proven  
21 reserves. Consequently, the price for the non-producing proven reserves will be

1 discounted to reflect the anticipated costs to drill, complete, and tie in those future  
2 wells. Second, even though there is a high degree of confidence with both  
3 producing and non-producing proven reserves that a certain volume of gas can be  
4 produced, there is greater confidence when the reserves are already producing. To  
5 account for this risk, the price for the non-producing proven reserves will typically  
6 be discounted by some percentage based on the particulars of each property and  
7 the parties.

8 **Q. WHY DO PRODUCERS GENERALLY NOT ENTER INTO LONG-TERM,**  
9 **FIXED-PRICE SUPPLY CONTRACTS?**

10 A. Producers are generally optimists. Producers believe the market price for gas will  
11 increase over time for the reasons outlined in Julia Ryan's direct testimony. Plus,  
12 producers would like to capture gains from price volatility. Producers do not want  
13 to miss the chance to make high margins on production as prices increase. If a  
14 producer enters into long-term fixed-price contracts at today's prices, it loses that  
15 opportunity. At a minimum, a producer willing to enter into a long-term fixed-  
16 price contract would want to charge a premium over today's price in return for  
17 missing future price increases. In addition, a long-term supply contract creates  
18 counterparty risk for a producer as the buyer could default.

19 Some oil and gas leases also tie the royalty owed to the mineral owner to the  
20 market price of gas, regardless of the price for which the producer has agreed to  
21 sell the gas. If a producer were to enter into a long-term, fixed-price supply

1 contract and market prices increased, the producer would owe more royalties,  
2 which would reduce the producer's profitability and is another reason producers  
3 avoid long-term, fixed-price supply contracts.

4 **Q. WHY THEN WOULD PRODUCERS BE INTERESTED IN SELLING GAS**  
5 **RESERVES OR ENTERING INTO A JOINT DEVELOPMENT**  
6 **AGREEMENT WITH COSGCO?**

7 A. Producers regularly sell assets to reposition their portfolios. In today's low price  
8 environment, a producer may have trouble servicing its debt, may not have  
9 sufficient capital on hand to develop its leases by drilling new wells, or may  
10 choose to spend available capital on other properties in its portfolio. In such  
11 situations, a sale or joint development agreement could be attractive to the  
12 producer. A producer could also be interested in a joint development agreement  
13 for other reasons. For example, the producer may be willing to reduce its interest  
14 in a property in exchange for having new wells drilled to increase production from  
15 that property. In addition, the long-term nature of the COSG Program could allow  
16 producers to enter into long-term contracts (with more favorable price terms) with  
17 well drilling and service companies, which would also improve the producer's  
18 economic return.

1 **Q. WHY IS AN EXPEDITED REVIEW OF COSGCO'S POTENTIAL**  
2 **ACQUISITIONS AND DRILLING PROGRAMS NECESSARY?**

3 A. Participants in the oil and gas industry generally are not accustomed to utility  
4 regulatory oversight and typically will not wait 6 to 12 months for regulatory  
5 approval from multiple states as a condition to closing a transaction or entering  
6 into service contracts. Of course, a limited number of producers might be willing  
7 to wait, particularly if the deal is sufficiently advantageous for them. However, if  
8 COSGCO is limited to only doing deals with producers that are willing to wait, it  
9 may miss many opportunities to make strategic acquisitions or arrangements that  
10 may optimize the COSG Program and its benefit for the Company's customers.

11 **IV. BHEP'S ROLE IN THE COSG PROGRAM AND ITS**  
12 **BACKGROUND, EXPERIENCE AND EXPERTISE**

13 **Q. WHAT IS BHEP'S ROLE IN THE COSG PROGRAM?**

14 A. As described in Ivan Vancas' direct testimony, BHUH will utilize BHEP's  
15 expertise and experience in property acquisition, deal structuring, and drilling,  
16 completing and operating natural gas properties. No matter the acquisition  
17 structure, BHEP would have a role in advising COSGCO with regard to the  
18 evaluation of potential properties and proposed operations. BHEP's subsequent  
19 role for each acquired property will likely vary. For example, if COSGCO  
20 acquires 100% of the working interest in a property, BHEP would be COSGCO's  
21 contract operator, or if COSGCO enters into a joint development agreement with



1 BHEP, BHEP would be the operator under the JOA for that property. Of course,  
2 the Commission will be able to consider BHEP's subsequent role when particular  
3 proposed COSGCO acquisitions are brought to the Commission as provided in the  
4 COSG Agreement.

5 **Q. PLEASE DESCRIBE THE CORPORATE STRUCTURE OF BHEP.**

6 A. BHEP is a subsidiary of Black Hills Non-Regulated Holdings, LLC, which in turn  
7 is a subsidiary of Black Hills Corporation. Black Hills Non-Regulated Holdings,  
8 LLC and BHEP are separate and independent from BHUH and Black Hills  
9 Corporation's various gas and electric utilities.

10 **Q. PLEASE DESCRIBE BHEP.**

11 A. BHEP has been drilling and operating oil and natural gas wells for more than 40  
12 years. It began drilling in the Powder River Basin in Wyoming in the 1970s and  
13 was acquired by Black Hills Corporation in 1986. BHEP is still producing oil and  
14 gas from most of its early wells. Headquartered in Denver, today BHEP operates  
15 almost 700 wells in Colorado, New Mexico, and Wyoming. BHEP also has  
16 working interests in wells that are operated by third-parties in California,  
17 Louisiana, Montana, North Dakota, Oklahoma, and Texas. BHEP employs more  
18 than 60 professional engineers, geologists, field personnel, land and title  
19 professionals, petro-techs, and accountants.

20 At the end of the 2014, BHEP had proven reserves of 101.4 billion cubic feet  
21 equivalent of natural gas, crude oil and natural gas liquids. During 2014, BHEP's

1 operated net gas production averaged approximately 20 million cubic feet per day.  
2 Associated with this daily natural gas production are 920 barrels per day of oil  
3 production and 370 barrels per day of natural gas liquids production.

4 BHEP has approximately 337,000 developed and undeveloped net acres under  
5 lease. (The industry calculates “net” acres by multiplying a producer’s working  
6 interest in particular property by that property’s number of acres, so a 75%  
7 working interest in a 10 acre property results in 7.5 net acres.) One of BHEP’s  
8 most significant assets is its 73,000 net acres in the Mancos Shale, a shale resource  
9 in the Southern Piceance Basin on the western slope of the Rocky Mountains in  
10 Colorado. This area contains 29.6 billion cubic feet equivalent of BHEP’s existing  
11 reserves, and BHEP engineers currently estimate approximately 2 trillion cubic  
12 feet of gas resource potential within its Southern Piceance Basin assets.

13 BHEP has bought and sold working interests, entered into many joint development  
14 agreements, and has operating experience on private, state, federal and Native  
15 American lands. BHEP has experience drilling and operating wells with measured  
16 depths exceeding 20,000 feet, horizontal wells with lateral lengths of more than  
17 9,000 feet, and four decades of experience with hydraulic fracturing. With respect  
18 to environmental issues, BHEP has an excellent reputation in the industry and with  
19 its regulators, and has never had a significant environmental issue regarding its  
20 operations. BHEP is always looking for ways to be proactive as it seeks to  
21 balance development and environmental stewardship. Every Black Hills corporate

1 employee (including BHEP's employees) must adhere to Black Hills  
2 Corporation's code of business conduct, which assures responsible environmental  
3 stewardship. BHEP has a history of supporting public policies that allow for  
4 responsible development of energy resources through sound energy and  
5 environmental policy. For example, in 2010, BHEP voluntarily entered into  
6 agreements with the Colorado Department of Wildlife regarding minimizing,  
7 mitigating and avoiding impacts to wildlife resources throughout more than 550  
8 square miles in western Colorado.

9 **Q. WHAT IS THE SUCCESS RATE BHEP HAS ACHIEVED IN DRILLING**  
10 **WELLS DURING THE LAST THREE YEARS?**

11 A. BHEP has achieved a 100% success rate in its gas appraisal and development  
12 drilling program, which has been focused on its Mancos Shale properties.

13 **Q. HAS BHEP EXPERIENCED ANY IMPROVEMENT IN ITS DRILLING**  
14 **AND COMPLETION EFFICIENCIES IN ITS MANCOS DRILLING**  
15 **PROGRAM?**

16 A. Yes. BHEP has realized improved efficiencies by, among other things, drilling  
17 more wells per drilling pad, drilling longer horizontal laterals, and completing  
18 more hydraulic fracturing stages per well. In addition, with the decline in crude  
19 oil prices in 2015, BHEP has seen 20-40% reductions in third-party service  
20 provider costs, enabling BHEP to obtain higher quality services for the same or  
21 lower costs compared to previous years. Improvements in drilling and completion

1 efficiencies have materially reduced BHEP's gross finding and development costs  
2 (which include drilling and completion costs) from over \$3.90 per thousand cubic  
3 feet equivalent (MCFE) in 2011 to approximately \$1.50/MCFE today.

4 **Q. HOW DO BHEP'S OPERATIONAL COSTS COMPARE TO THE COSTS**  
5 **OF OTHER OPERATORS IN THE INDUSTRY?**

6 A. BHEP has a history of being a low cost operator with a three-year average of  
7 annual lease operating expenses of \$1.11/MCFE. By comparison, the industry  
8 average for lease operating costs over this period in Rocky Mountain producing  
9 basins was \$1.47/MCFE, according to Ponderosa Advisors, LLC. Lease operating  
10 expenses include the costs for operating and maintaining productive wells, such as  
11 the cost of labor for operating and maintaining the equipment on the lease, repairs  
12 and supplies, utilities, automobile and truck expenses, insurance and overhead  
13 such as accounting and supervision, excluding gathering, compression and  
14 processing costs and production taxes. In addition, based on its historical  
15 performance, BHEP anticipates its operating expenses will remain stable for the  
16 foreseeable future.

17 **Q. IS BHEP QUALIFIED TO ASSIST BHUH UNDER THE COSG**  
18 **PROGRAM?**

19 A. Yes. As described above, BHEP has extensive experience in the oil and gas  
20 industry, including the development and operation of shale or tight gas resources.  
21 Consequently, BHEP is qualified and exceptionally well suited to assist BHUH

1 under the COSG Program, including assistance with property acquisition, deal  
2 structuring, drilling and production issues, and operating properties.

3 **V. CONCLUSION**

4 **Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?**

5 A. Yes.