Direct Testimony
T. Aaron Carr

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Exhibits

I. INTRODUCTION AND QUALIFICATIONS

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is T. Aaron Carr. My business address is 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 currently employed by Black Hills Corporation ("BHC" or "Black Hills") as Director of Corporate Development. In this capacity, my areas of responsibility include strategic analysis of business development opportunities for both regulated and unregulated subsidiaries of 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. I received a Bachelor of Science degree in Business Administration from the University of Wyoming in 1996 and a Masters of Business Administration from the University of South Dakota in 2001. While at BHC, I have had roles as Corporate Development Analyst, Risk Analyst, and Senior Manager of Budgets and Forecasts. In my current role, which I have held since 2008, I have led numerous projects both for the Utility and Non-Regulated Segments of BHC and its subsidiaries and affiliates. These projects included valuation, due diligence and integration efforts for oil and gas and utility acquisitions, RFP submissions for new electric generation to other utilities, renewable energy project development, and other strategic initiatives for BHC.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THIS COMMISSION?

A. No.

II. PURPOSE OF TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. My testimony describes the oversight that the Commission will have over the proposed cost of service gas program (the "COSG Program") as well as the protections that have been built into it to ensure the COSG Program works as designed in providing long-term price stability and potential customer savings. My testimony also discusses the specific mechanisms incorporated into the COSG Agreement (the "COSG Agreement") that provide for and facilitate Commission oversight, including (a) the retention of independent accounting and hydrocarbon monitors, and (b) guidelines for future acquisitions and drilling programs to be approved by the Commission under the COSG Program. Under the COSG Agreement, properties with natural gas reserves will be acquired and developed by a subsidiary of BHUH referred to as "COSGCO." I will also explain a hypothetical model used by the Company to compare the potential cost of gas under the COSG Program to the projected cost of purchasing gas at market prices over the same period.

III. GENERAL DESCRIPTION OF COSG PROGRAM OVERSIGHT

Q. WILL THE COMMISSION HAVE AN EFFECTIVE OPPORTUNITY TO ASSESS THE PRUDENCE OF THE COSG PROGRAM?

A. Yes. As is explained in greater detail below, as part of its application and the proposed COSG Program, the Company is proposing that a series of reviews, guidelines, and independent professional monitors be approved and implemented to provide regular oversight and approval opportunities. First, before the COSG Program is implemented, the Company is requesting that the Commission conduct a prudency review of the proposed COSG Program structure and operations, as well as the COSG Agreement and its guidelines for future gas reserve acquisitions and development. The COSG Agreement is included as Exhibit IV-1 to the Direct Testimony of Ivan Vancas. Second, as provided in the COSG Agreement, the Commission will have the opportunity to review all proposed reserve acquisitions and drilling plans. Proposed acquisitions and proposed drilling plans under the COSG Program will also be thoroughly reviewed by an independent hydrocarbon monitor ("Hydrocarbon Monitor"), and a report of that review will be provided to the Commission. The Hydrocarbon Monitor will also provide reports concurrent with each five-year review of the drilling program. This report will also be provided to the Commission for review. Third, an independent accountant (the "Accounting Monitor") will conduct annual accounting assessments of the financial information of the COSG Program and provide an assurance report of its assessment, which will be provided to the Commission. The Accounting Monitor's assessment will verify the accurate determination of "Hedge Costs" and "Hedge Credits" under the COSG Program. The oversight of both monitors along with the numerous economic criteria built into the Program is designed such that any future capital deployment by COSGCO will be reasonably likely to create savings for customers over the life of the wells, in addition to the primary goal of providing price stability for customers.

IV. PRUDENCY REVIEW

Q. DOES THE COSG PROGRAM PROVIDE THE COMMISSION WITH ONGOING OPPORTUNITIES TO ADDRESS PRUDENCY CONCERNS? IF SO,

CAN YOU EXPLAIN SPECIFICALLY WHEN SUCH OPPORTUNITIES WOULD ARISE?

A. Yes. As noted, the Company is seeking, through its application, to have the Commission conduct a prudency review of the COSG Program structure and the COSG Agreement before the Company could participate in the COSG Program. Thereafter, the Commission will have the ability to review (a) any proposed acquisitions, and (b) each newly proposed drilling plan. Specifically, prior to any reserve interest being acquired, Black Hills Utility Holdings, Inc. ("BHUH") would be required to provide to the Hydrocarbon Monitor all of the "Acquisition Information" set forth in Exhibit A of the COSG Agreement. If, based on that information, the Hydrocarbon Monitor determines that the proposed acquisition does not satisfy the "Acquisition Criteria" in Exhibit A to the COSG Agreement, the proposed acquisition would not be included in the COSG Program. If the Hydrocarbon Monitor concludes that the acquisition satisfies the Acquisition Criteria, the monitor's written report would be submitted to the Commission, which would have 60 days to review the proposed acquisition and determine whether it is approved. If no regulatory commission or board approves an acquisition (or too few to make it feasible), the acquisition will be abandoned. If fewer than all regulatory commissions or boards approve the acquisition, it may be scaled or the drilling plan adjusted, if feasible, to meet the needs of only the participating utilities. Any capital and operating expenses incurred by COSGCO to acquire, develop and operate the property, and all production from the property, would be allocated solely to the participating utilities.

In addition, under the COSG Program, the Commission would be able to review proposed updates to each drilling plan every five years following approval of the first property acquisition. Specifically, at five-year intervals, BHUH would be required to provide the Hydrocarbon Monitor with a proposed drilling plan for the next five years. The submission would include all the information described in Section 4.4 of the COSG Agreement. The Hydrocarbon Monitor would issue a written report to the utilities participating in the COSG Program, the commissions or boards who regulate those utilities, and BHUH. The report would state whether the drilling plan satisfies the "Drilling Plan Criterion" in the COSG Agreement. If the Hydrocarbon Monitor determines that a drilling plan for a particular property does not satisfy the Drilling Plan Criterion, then COSGCO would not pursue the proposed drilling plan unless and until an alternate drilling plan was approved. If, however, the Hydrocarbon Monitor concludes that the drilling plan satisfies the "Drilling Plan Criterion," the Commission would then have 60 days to review and approve the drilling plan.

Q. IF A FIVE-YEAR DRILLING PLAN IS NOT APPROVED BY THE COMMISSION, THEN WHAT WOULD HAPPEN?

A. If the Commission elected not to approve a utility's participation in a five-year drilling plan, the Company would continue to receive benefits from prior approved drilling plans, but would not able to participate in any of the benefits derived from the drilling plan that was not approved.

Q. IF THE COMPANY PARTICIPATES IN AN ACQUISITION AND THE INITIAL DRILLING PLAN, BUT DOES NOT PARTICIPATE IN A SUBSEQUENT DRILLING PLAN ON THE PROPERTY, WOULD IT BE PERMITTED TO PARTICIPATE IN LATER PROPOSED DRILLING PLANS?

A. Maybe. If the Company did not participate in a drilling plan, it could not receive any benefits from that drilling plan, but may still participate in later drilling plans on that property, provided its participation is not detrimental to existing participants.

Q. WHAT HAPPENS IF THE COMPANY DOES NOT PARTICIPATE IN AN ACQUISITION?

A. If the Company did not participate in an acquisition, it could not receive any benefits from the existing wells, if any, on that property and from wells drilled under the drilling plan approved in connection with the acquisition. However, the Company may still participate in later drilling plans on that property, provided its participation is not detrimental to existing participants. The Company could also participate in subsequent acquisitions if and when proposed by BHUH.

V. ACCOUNTING AND HYDROCARBON MONITOR

Q. PLEASE PROVIDE A DESCRIPTION OF HOW THE PROPOSED HYDROCARBON AND ACCOUNTING MONITORS WOULD ENSURE THAT THE PROGRAM FUNCTIONS AS DESIGNED.

A. Commissions, boards and consumer advocates may lack the personnel with technical expertise and experience with natural gas production to monitor the functions of the COSG Program. Therefore, the independent Hydrocarbon Monitor would be retained to provide that expertise and experience. For each proposed property acquisition and each proposed drilling plan, the Hydrocarbon Monitor would review the information and reports provided by BHUH, as required by the COSG Agreement on the reserves, production, drilling assumptions, and the associated economics. The monitor would then produce an independent report to be shared with the Commission, each participating utility, and BHUH. In addition, BHUH will provide an annual report to the Hydrocarbon Monitor, which will contain, among other things, information regarding drilling and production activities and provide estimates of existing reserves and production capabilities. The Hydrocarbon Monitor would review BHUH's annual report, including the reserves reported in that report, and assess in writing whether BHUH's calculations were accurate and consistent with standard industry practice.

The independent Accounting Monitor would also annually assess the financial information of the COSG Program, and issue an assurance report of its assessment. That report would be provided to the Commission for its review.

The Monitors would be selected based on mutual agreement between BHUH and Commission, and would be retained by BHUH as an allowable expense under the COSG Program.

Q. SPECIFICALLY, WHEN WOULD THE MONITORS BE INVOLVED IN THE VARIOUS STAGES OF REVIEW UNDER THE COSG PROGRAM?

A. The Monitors would be retained at the inception of the COSG Program and would provide services throughout the operation of the program. The Hydrocarbon Monitor would be actively involved in assessing each proposed acquisition to determine whether it satisfies the Acquisition Criteria. It would also review each initial drilling plan and each updated drilling plan. The Accounting Monitor would be involved in conducting an assessment of BHUH's calculations under the COSG Program.

Q. HOW WOULD THE COSTS/EXPENSES OF THE MONITORS BE PAID?

A. The costs of the Monitors would be treated as an allowable cost for inclusion in the calculation of Hedge Credits and/or Hedge Costs under the COSG Program (as described in the Direct Testimony of Chris Kilpatrick) and be paid directly by BHUH.

VI. GUIDELINES FOR FUTURE ACQUISITIONS AND DRILLING PROGRAMS

Q. HOW DOES THE COMPANY PROPOSE TO BALANCE THE INTERESTS OF THE COMPANY AND CUSTOMERS UNDER THE COSG PROGRAM?

A. The COSG Agreement contains numerous guidelines that are designed to safeguard the interests of the Company's customers. As noted, the Commission will have the opportunity to assess the operation of the COSG Program at critical stages, namely when a reserve interest is proposed to be acquired and when drilling plans are updated every five years. In addition to the price stability the COSG Program is anticipated to provide, to produce natural gas from an acquisition or drilling plan, it must be reasonably anticipated to be less than the long term market price forecast costs of acquiring the same volumes of gas on a net present value basis over the life of the wells, as determined at the time of acquisition or upon approval of that drilling plan.

Q. PLEASE IDENTIFY THE GUIDELINES WITHIN WHICH THE COSG PROGRAM WOULD OPERATE.

A. For the Commission's convenience, Exhibits A, B, and C of the COSG Agreement contain a detailed breakdown of each of the key acquisition criteria, drilling plan criterion, and hedge target thresholds that are incorporated into the COSG Program and the COSG

Agreement. I will review in my testimony below these guidelines and criteria as well as other customer protections.

Q. WHAT ACQUISITION SAFEGUARDS WILL COSGCO BE REQUIRED TO FOLLOW UNDER THE PROPOSED GUIDELINES?

A. The Company believes it is important to find reserve interests with attributes that fit a long-term price stability program. The Company proposes that each reserve interest must have the following three attributes:

(1) The reserve area must be located in the Rockies or Mid-Continent regions and must contain geologic formations that have well-established histories of production.

(2) While producing fields generally can produce a mix of oil, natural gas, and natural gas liquids, a reserve interest for the COSG Program must be anticipated to contain, on a Btu content basis, at least 50% natural gas (methane).

(3) The property must have an expected remaining life of at least fifteen (15) years.

(4) While there is a range of designations for reserves denoting the degree of certainty that the predicted quantity of gas is commercially recoverable from a well (proved, probable, and possible), a reserve interest for the COSG Program must have proved developed producing ("PDP") reserves of at least 50% of its net present value.

Q. WHY MUST THE RESERVE AREA BE LOCATED IN THE ROCKIES OR MID-CONTINENT REGIONS?

A. In general, prices in the Rockies and Mid-Continent regions correlate well with the prices in the regions from which the Company currently obtains gas to meet its customers' needs. In addition, given Black Hills Exploration and Production, Inc.'s ("BHEP") familiarity with the Rockies and Mid-Continent regions, pursuing reserves interests in those regions would put COSGCO in the best position possible to take advantage of its affiliates' experience and management efficiencies.

Q. WHY THE 50% METHANE AND THE 50% PDP REQUIREMENTS?

A. The COSG Program is intended to be a long-term natural gas hedge program. As such, a high proportion of the property value should be attributable to lowest risk reserve category, PDPs, and the focus should be on natural gas as opposed to other commodities.

Q. IS THERE A POTENTIAL THAT COSGCO COULD ACQUIRE A RESERVE INTEREST FROM BHEP AND, IF SO, WHAT PROTECTIONS WOULD BE PUT IN PLACE FOR SUCH A TRANSACTION?

A. Yes. If COSGCO were to propose acquiring a reserve interest from BHEP, any such transaction would have to be a fair market transaction as determined by a third-party appraiser, and COSGCO would conduct the cost/benefit analysis described above (which would need to be confirmed by the Hydrocarbon Monitor). In other words, before it could recommend approval of any transaction between COSGCO and BHEP, the Hydrocarbon Monitor would have to conclude that the reasonably anticipated cost of gas from any proposed acquisition (and/or its drilling plan) over the life of the reserve interest is less than the long term market price forecast for the same volumes of gas over the same period on a net present value basis.

Q. WHAT IS THE ACQUISITION AND DRILLING COST/BENEFIT ANALYSIS?

A. Essentially, in order to demonstrate the reasonably anticipated benefit of an acquisition for customers, the reasonably anticipated cost of gas from an acquisition (and its drilling plan) is less than the long term market price forecast costs for the same volumes of gas. This would be evaluated at the time of each proposed acquisition, over the life of the production of the wells, and on a net present value basis. The discount factor would be the "Cost of Capital," as defined in the COSG Agreement. Exhibit AC-1, which is attached, details this calculation. Similarly, to demonstrate the reasonably anticipated benefit of each drilling plan, every five years, the drilling plan would be reviewed. For the drilling plan to go forward, the reasonably anticipated cost of gas from wells to be drilled under the proposed plan over the economic life of the wells to be drilled must be anticipated to be less than the long term market price forecast costs for the same volumes of gas on a net present value basis over the same period. This determination would be based on the information available at the time the drilling plan is reviewed.

Q. PLEASE DESCRIBE IN DETAIL WHAT YOU MEAN BY PROGRAM SIZE GUIDELINES.

A. Like any prudent portfolio management strategy, the Company believes that it would not be prudent to tie up all of its purchased volumes in a long-term hedge program. As such, the COSG Program imposes a limit on the volumes COSGCO could produce annually under the COSG Program. Specifically, this guideline would limit the Company's proportionate share to 50% or less than the Company's weather-normalized annual firm demand, consistent with the recommendations of Aether Advisors, LLC and the Company.

Q. WHAT HAPPENS IF THE COMPANY'S WEATHER-NORMALIZED ANNUAL FIRM DEMAND DECREASES OVER TIME?

A. The COSG Program will work to accommodate changing demand if a utility sees a year-over-year weather-normalized decrease of 10 percent or more, and the reduced demand is expected to continue. Steps to reduce the COSG Program output could include: reallocating production to other utilities subject to the limitations of the COSG Agreement and adjusting drilling programs where doing so would be prudent.

Q. WHAT ARE THE BENEFITS AND PROTECTIONS OF THE COSG PROGRAM ACCOUNTING AND CALCULATIONS?

A. As more fully described below, the benefits and protections include: (1) Revenue Credits for Associated Production; (2) Limitations on Allowed Program Expenses; (3) Application of the Full Cost Method of Depletion; and (4) Revenue Sharing Methods. I discuss each of these in detail below.

Q. HOW ARE REVENUE CREDITS FOR ASSOCIATED PRODUCTION A CUSTOMER BENEFIT?

A. It is likely that a producing gas interest will also produce associated crude oil and natural gas liquids (NGLs) during extraction. The Company proposes that COSGCO will sell to the market 100% of all associated oil and NGLs (after the cost of processing, transportation, marketing, etc.) as a credit to the production cost of natural gas under the COSG Program. The net proceeds will be treated as a credit for the benefit of customers in the hedge adjustment calculation.

Q. HOW ARE THE PROPOSED LIMITATIONS ON ALLOWED EXPENSES FOR PURPOSES OF CALCULATING COSG PROGRAM COSTS AND HEDGE ADJUSTMENTS A CUSTOMER PROTECTION?

A. It is a protection for two reasons. First, only directly charged costs including time from employees of Black Hills Service Company ("BHSC"), BHUH, and BHEP will be included as allowed expenses in the COSG Program. No indirect costs will be attributable to the program. Second, the expenses will include only those expenses associated with the direct operations of the COSG Program. For example, expenses would not include such expenses as advertising expenses, charitable contributions, lobbying costs, etc.

Q. WITH REGARD TO THE "FULL COST METHOD OF DEPLETION", WHAT IS DEPLETION?

A. Depletion is the methodology for expensing capital costs associated with drilling, completing, and plugging and abandoning a well, similar to how expenses are depreciated in other settings.

Q. WHAT ARE PLUGGING AND ABANDONMENT COSTS?

A. Plugging and abandonment costs refer to the costs to cease well operations and close and reclaim a well, similar to what occurs when a power plant is decommissioned.

Q. HOW IS THE MANNER IN WHICH DRILLING, PLUGGING AND ABANDONMENT COSTS ARE TREATED UNDER THE COSG PROGRAM A CUSTOMER PROTECTION?

A. A number of customer protections are included in the depletion methodology. First, COSGCO will utilize a modified "Full Cost Method" of accounting for depletion. The

Full Cost Method will be modified from standard oil and gas accounting methods to only account for PDP reserves and not proved undeveloped ("PUD") reserves. COSGCO will also add the amortization of the future cost of plugging and abandoning wells at the end of their useful life into the depletion calculation. Finally, COSGCO will have its own reserve pool separate from BHC's BHEP subsidiary.

Q. HOW IS THE "FULL COST METHOD" OF ACCOUNTING A CUSTOMER PROTECTION?

A. Utilizing the Full Cost Method allows for a pooling of all reserve acquisition and drilling costs together. The depletion rate is then calculated by dividing the total pool of costs by the total proved producing reserves. This has the effect of spreading drilling risk over the entire amount of reserves previously drilled. Thus, fluctuations in drilling costs or reserve recoveries from wells are essentially "averaged" via the depletion calculations. The other depletion option, "Successful Efforts," requires that any capital expenditure associated with drilling an unsuccessful well is added to depletion expense at the time the well is drilled. Though unsuccessful wells are expected to be rare, utilizing that method could subject COSGCO to higher depletion charges within a single year rather than averaged out over the life of all reserves, causing greater annual variation in the production cost of the COSG Program. The Full Cost Method essentially shares the drilling risk with previously drilled or acquired wells already in the program and cost pool and spreads cost variations over the productive life of all the wells.

Q. HOW IS MODIFYING THE FULL COST METHOD TO EXCLUDE PUD RESERVE A PROTECTION FOR CUSTOMERS?

A. Excluding PUD reserves, which are normally included for depletion calculations, has the effect of including only known capital costs and known PDP reserves. This reduces the chance for error estimating future reserves added per well, in addition to potentially inaccurate forecasts of capital costs per well. Further, it also makes sense to exclude future drilling locations because future drilling may be curtailed or suspended in accordance with the COSG Agreement.

Q. WHY ARE PLUGGING AND ABANDONMENT COSTS INCLUDED IN THE AMORTIZATION CHARGE AND HOW IS THAT A CUSTOMER PROTECTION?

A. Much like a decommissioning charge for power plants, it is appropriate to recover future costs to plug and abandon wells over time as the benefit of the COSG Program is received by customers. The most appropriate way to account for this is to estimate the plugging and abandonment liability at the start of production and to amortize those costs on a unit of production method to better match that obligation to the time the benefits of production were received from each well. This amortization also has the effect for customers of avoiding large expenses in the year a well is plugged and abandoned.

Q. WHAT REVENUE SHARING BENEFITS ARE INCORPORATED INTO THE COSG PROGRAM?

A. The costs and benefits of the COSG Program are ultimately included into "Hedge Credits" and "Hedge Costs." As explained in more detail in Chris Kilpatrick's Direct Testimony, Hedge Credits are additional incremental revenue amounts that flow to the benefit of customers. If the actual ROE of the COSG Program is more than 100 basis points higher than the allowed ROE, then that additional incremental revenue, adjusted for taxes, would be credited back to the Company for the benefit of customers. In periods of increasing market gas prices, that would otherwise cause the cost of gas for the Company's customers to increase, Hedge Credits would create an off-setting deduction that would decrease the effective cost of gas paid by the Company's customers.

Q. WHAT WOULD HAPPEN IF THE COST OF SERVICE GAS PRICE WAS HIGHER THAN THE MARKET PRICE OF GAS?

A. If market prices decrease and revenues generated by COSGCO's sales of COSG Program gas (after adjusting for the risk sharing described below) were higher than the market price of gas, then the Company's customers would bear a "Hedge Cost." However, this cost would only be incurred if the actual ROE was more than 100 points lower than the allowed ROE.

Q. PLEASE FURTHER EXPLAIN HOW RISKS ARE SHARED UNDER THE COSG PROGRAM.

A. Built into the COSG Program is a risk-sharing mechanism. As part of the mechanism, if the actual ROE exceeds the allowed ROE, BHUH would receive the benefit of any additional revenue up to the point where actual ROE exceeds allowed ROE by 100 basis points. Once the actual ROE exceeds the allowed ROE by more than 100 basis points, any additional incremental revenue would be passed on to the Company for the benefit of its customers. Similarly, if the actual ROE is less than the allowed ROE, BHUH, via COSGCO's results, would bear the losses resulting from that difference up to the point where actual ROE was less than the allowed ROE by 100 basis points. If actual ROE reached the point where it was more than 100 basis points less than the allowed ROE, the Hedge Cost described above would come into effect, and the additional incremental cost would be passed on to the Company and its customers. In this way, the COSG Program provides an incentive to BHUH and COSGCO to control costs, and increase revenue and returns.

Q. WHAT OTHER CUSTOMER PROTECTIONS ARE EMBEDDED WITHIN THE COSG AGREEMENT?

A. COSGCO's involvement, as a non-regulated, wholly-owned subsidiary of BHUH, is intended to benefit Customers. First, COSGCO will not be funded by the Company, keeping BHUH and utility ring-fencing protections intact. Second, the ownership structure has been designed to protect tax attributes associated with oil and gas drilling and production, the benefits of which are passed on to customers. Third, COSGCO's involvement allows for more transparency as a stand-alone entity. Fourth and finally, drilling plans will provide additional protection for customers, as they will dictate how, when and where drilling will occur and will be reviewed by the Hydrocarbon Monitor and the Commission every five years.

Q. PLEASE ELABORATE ON THE IMPORTANCE OF THE LEGAL ENTITY STRUCTURE AND ITS RELATED TAX CONSEQUENCES.

A. The Internal Revenue Code ("IRC") provides for the immediate deduction for federal income tax purposes all "intangible drilling costs" or "IDCs" *so long as* the requirements for qualification under the IRC are met. Intangible drilling costs are defined as costs related to drilling and necessary for the preparation of wells for production, but that have no salvageable value. These include costs for wages, fuel, supplies, repairs, survey work, and ground clearing. IDC's typically compose 60 to 80 percent of total drilling costs. The government provides the greatest amount of IDC tax benefits for what are known as "independent producers." On the other hand, the IDC tax benefit is limited for large "integrated producers" that own the entire value chain from oil in the ground to the gas pump, or in the case of natural gas, ownership of gas in the ground to the burner tip. This transaction was structured with a purpose of maintaining qualification as an "independent producer" and maximizing IDC tax benefits. The maintenance of independent producer status was accomplished by segregating the activity of COSGCO in a stand-alone legal entity. By utilizing a structure that maximizes tax benefits, utility customers are better off because they receive the benefit of IDC tax benefits that serve to defer the payment of tax and build deferred tax balances. Such deferred tax balances reduce Investment Base due to their nature as cost-free capital and reduce the effective cost of gas under the COSG Program.

Q. WHY IS THIS LEGAL STRUCTURE AND THE COSG AGREEMENT BETTER FOR CUSTOMERS THAN RATE BASING RESERVES AT EACH UTILITY?

A. It makes more sense to include gas-related costs in the GCA adjustment mechanism where gas costs currently are recovered. This also gives the benefit of adjusting COSGCO's investment basis periodically for this calculation where the investment base is likely to decline more rapidly than standard utility rate base due to the higher depletion expense of oil and gas assets as compared to depreciation expense on typically long-lived utility assets. If the reserves were placed in rate base while drilling and production proceeded under the COSG Program, utilities would have a constant need to file rate cases. Furthermore, declines in investment base (rate base for utilities) would not be realized by the customers until the next general rate case. Also, if reserves were carved up when acquired and placed into each utility, it would be administratively burdensome to deal with multiple entities controlling smaller working interests in the same property and would incur significantly higher transaction and administrative costs on an on-going basis.

Q. AS COSGCO IS NOT A REGULATED ENTITY, WHAT OVERSIGHT WILL THE COMMISSION HAVE OVER ITS OPERATIONS?

A. While the Commission will not regulate COSGCO, it will have additional oversight and transparency of the COSG Program as compared its oversight of the procurement of natural gas conducted daily by BHUH's gas supply group for the Company. That is, the Commission periodically verifies the prudency of the Company's actions and expenditures but vests BHUH with the responsibility to make prudent decisions in the day-to-day supply of natural gas. The COSG Agreement also specifies how and what costs are allowed to be included in the COSG Program. The Monitors will provide reports on COSGCO's operations, costs and assets. Each new acquisition and drilling program must meet specific guidelines before being pursued by COSGCO, and the Commission will see the Hedge Cost or Credit in the Utility's GCA filings. Furthermore, the Commission has the opportunity to approve acquisitions and drilling plans that are the foundations of the COSG Program. The reports of the Independent Monitors, along with approval of acquisitions and drillings plans, provide the Commission with significantly greater transparency and oversight of gas costs than is otherwise available through market purchases.

VII. ECONOMIC EVALUATION OF THE COSG PROGRAM

Q. HAS BLACK HILLS CREATED AN ECONOMIC EVALUATION MODEL FOR THE COSG PROGRAM?

A. Yes, for a hypothetical program. Based on historical and market data, information obtained from BHEP and other sources, and estimated costs and projections derived from various assumptions, Black Hills generated an economic model to calculate the net present value ("NPV") of the production costs of the COSG Program compared to the NPV of market gas purchases for the same volumes over the same period. A copy of the model is attached to my testimony as Exhibit AC-2.

Q. PLEASE EXPLAIN THE PURPOSE OF THE MODEL.

A. The model was compiled on a hypothetical cost of service program to educate and inform the parties to this docket as to the mechanics and formulas driving the effective cost of gas under the COSG Program and illustrate the regulatory-like functionality of the COSG Program parameters consistent with the COSG Agreement (i.e. revenue requirements, cost of service recovery, regulated cost of capital, etc.).

Q. WHAT ARE THE COMPONENTS OF THE MODEL AND WHAT DOES IT SHOW?

A. The Model shows the financial mechanics of how a hypothetical cost of service gas program under the COSG Agreement. For illustrative purposes, the Model shows performance over a 10-year period. Under the COSG Program, when an acquisition is actually made, the calculations would be made over the life of the wells included in the COSG Program.

The Model compiles the various inputs and assumptions to derive the annual Hedge Credit or Hedge Cost for the COSG Program over time. More specifically, Section 1 of the Model on pages 2-3 discloses the key inputs and drivers including drilling costs per well, production levels, natural gas price forecasts, capital structure, cost of capital and tax assumptions. Section 2 on page 4 displays the outputs and how a given reserve interest may be evaluated in the context of the COSG Program guidelines discussed earlier in my testimony. Finally, Section 3 presents the calculation of revenue requirements, financial statements and both book and tax depreciation and depletion calculations.

In addition, Column E, page 2 of the Model, contains the "Drivers and Assumptions Section," which shows the various inputs used. Column F, page 5 of the Model, highlights the formulas within the model that show how the results were derived. Specifically, Page 5, lines 6-12 shows the relative allocation (based on annual firm demand) amongst the state utilities that may participate under the COSG Program. Page 5, lines 19-26 show the ROE Sharing band mechanism, which demonstrates how, in a given year, a Hedge Credit would result or a Hedge Cost would be incurred. Page 6, lines 48-59 shows the categories of expenses for which recovery would be sought under the COSG Program. Finally, the calculation of the effective cost of gas per MMBtu under the COSG Program is calculated and compared against the market price forecast at page 6, lines 67-68.

Q. WHY WERE ASSUMPTIONS NEEDED TO GENERATE THE MODEL?

A. First, as the COSG Program has not yet been approved, COSGCO has not yet been formed or consummated any transaction to acquire gas reserves or reserve interests. As such, the precise capital investment that will be required for the acquisitions that would be part of the COSG Program are unknown at this time, as is the precise makeup of the reserve area where drilling under the COSG Program would take place. For this same reason, production amounts have to be estimated. Finally, operation and maintenance expenses vary by gas field and have to be estimated based on historical or other available information.

Q. WHAT ASSUMPTIONS ARE BUILT INTO THE MODEL?

A. The model incorporates certain assumptions, some of which are base assumptions and others relate to major categories of operating and maintenance expenses. The more significant base assumptions include the following:

- COSGCO purchases a baseline amount of PDPs at a market value transfer price (assumed in the model to be $1.00 per mcfe in reserves) consisting of a mix of vertical and horizontal wells at various stages of their respective lives;
- COSGCO obtains its interest in undrilled well sites under a drill-to-earn arrangement, pursuant to which COSGCO "carries" the operator for 5% of the capital costs and obtains 95% of the operator's share of the gas production;
- The costs to drill each well range from $10-11.2 million per well;
- It is assumed that capital expenditures are incurred and included for maintenance roads, water lines, evaporation ponds, and other infrastructure;
- Existing well and drilling locations include a spectrum of gas content from dry gas to liquid-rich gas, with 100% of the proceeds from COSGCO's share of any liquids being credited to the utilities participating in the COSG Program for the benefit of customers;
- Well locations in the hypothetical gas field vary in depth and lateral lengths, consistent with typical drilling and development operations; and

- Estimated ultimate recovery from the wells averages 10 billion cubic feet equivalent (Bcfe) per well.

With regard to the O&M assumptions, the model includes, among other things, the following assumptions:

- Lease operating expenses are based on a dollar-per-well-month and include an overhead charge to the well operator;
- Gas processing plant fees to extract natural gas liquids and refine/treat gas to pipeline quality specifications are included assuming typical gathering contract terms; and
- The production tax rate is 5.9%.

Q. WHAT SENSITIVITIES HAVE BEEN RUN ON THE ASSUMPTIONS CONTAINED IN THE MODEL?

A. Page 4 Lines 30-40 contains a matrix of net present value sensitivities to illustrate how the results of the COSG Program might change given a change in major assumptions. As displayed, the following assumptions were analyzed: (i) Price Forecast +/- 5% (ii) Commodity Production +/- 5% and (iii) Capital Spend +/- 5%. The 18 scenarios depicted are combinations of various production levels, capital spending levels per well, and varying commodity prices.

VII. <u>CONCLUSION</u>

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

Exhibit AC-1

Cost of Capital Calculation

Component	Cost	Weighting	Weighted Avg. Cost
Allowed Cost of Debt [1]	4.50%	40%	1.80%
Allowed ROE	9.86%	60%	5.92%
Total Cost of Capital			7.72%

Note:

1. The 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. The interest cost shown here is for illustration purposes.

BLACK HILLS COST OF SERVICE GAS COMPANY ("COSGCO") FINANCIAL MODEL

EXAMPLE MODEL -- FOR DISCUSSION PURPOSES ONLY

Jun-15

Please direct questions to:

Ivan Vancas	**Chuck Loomis**	**Aaron Carr**	**Justin Klapperich**
Vice President	*Vice President*	*Director*	*Manager*
ivan.vancas@blackhillscorp.com	chuck.loomis@blackhillscorp.com	aaron.carr@blackhillscorp.com	justin.klapperich@blackhillscorp.com
605-721-1428	605-721-1162	605-721-2368	605-721-1375

Key	Blue Font =	Input Values
	Green Font =	Linked to other cells within workbook
	Black Font =	Result of an equation
	Red Font =	**References & Formulas**
	Yellow Box=	**Input Variable**

A1	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P
	Line N	*Dollar Amounts in $Thousands*		Years:	0	1	2	3	4	5	6	7	8	9	10
	Tab:	**DRIVERS & ASSUMPTIONS**	FN	REF & FORMULAS		12/31/2016	12/31/2017	12/31/2018	12/31/2019	12/31/2020	12/31/2021	12/31/2022	12/31/2023	12/31/2024	12/31/2025
4	**Drilling Capital & Production Assumptions**														
5	Proven Developed Producing Reserves Acquired (MMcfe)				20,000										
6	Acquisition Price Assumption per mcfe Reserves				$ 1.00										
7	Acquisition Capital Investment			=F5*F6	$ 20,000										
8	Buy-In Wells				11	7	5	4	6	5	6	7	6	6	6
9	Cumulative Participating Wells			=E9+F8	11	18	23	27	33	38	44	51	57	63	69
10	Average Well Cost			=F17	$ 11,000	$ 11,204	$ 11,151	$ 11,094	$ 10,761	$ 10,412	$ 10,046	$ 10,232	$ 10,422	$ 10,614	$ 10,811
11	Drilling Capital			=F8*F10	$ 121,000	$ 78,425	$ 55,757	$ 44,374	$ 64,565	$ 52,059	$ 60,278	$ 71,626	$ 62,529	$ 63,686	$ 52,349
12	Total Capital Expenditures-Depletable			=F7+F11	$ 141,000	$ 78,425	$ 55,757	$ 44,374	$ 64,565	$ 52,059	$ 60,278	$ 71,626	$ 62,529	$ 63,686	$ 52,349
13	Capital Expenditures-Depreciable		(a1)		$ 7,500	$ 12,500	$ 9,000	$ 7,000	$ -	$ -	$ -	$ -	$ -	$ -	$ -
14	Grand Total Capital Expenditures			=F12+F13	148,500	90,925	64,757	51,374	64,565	52,059	60,278	71,626	62,529	63,686	52,349
15				INPUT											
16				OPTION											
17	Capital Expenditures-Avg Well Cost			2	11,000	11,204	11,151	11,094	10,761	10,412	10,046	10,232	10,422	10,614	10,811
18	1	High	+5%	FLEX %	11,550	11,764	11,709	11,648	11,299	10,932	10,549	10,744	10,943	11,145	11,351
19	2	Base		5.00%	11,000	11,204	11,151	11,094	10,761	10,412	10,046	10,232	10,422	10,614	10,811
20	3	Low	-5%		10,450	10,643	10,594	10,539	10,223	9,891	9,544	9,721	9,900	10,084	10,270
21				OPTION											
22	Gas Production (Mcf)			2		12,000,000	14,000,000	15,000,000	15,500,000	17,500,000	17,000,000	20,000,000	21,000,000	22,500,000	23,000,000
23	1	High	+5%	FLEX %		12,600,000	14,700,000	15,750,000	16,275,000	18,375,000	17,850,000	21,000,000	22,050,000	23,625,000	24,150,000
24	2	Base		5.00%		12,000,000	14,000,000	15,000,000	15,500,000	17,500,000	17,000,000	20,000,000	21,000,000	22,500,000	23,000,000
25	3	Low	-5%			11,400,000	13,300,000	14,250,000	14,725,000	16,625,000	16,150,000	19,000,000	19,950,000	21,375,000	21,850,000
26	Gas Production (MMBTU)					12,600,000	14,700,000	15,750,000	16,275,000	18,375,000	17,850,000	21,000,000	22,050,000	23,625,000	24,150,000
27	**Regulatory Assumptions**			INPUT											
28	Equity %			60%		60%	60%	60%	60%	60%	60%	60%	60%	60%	60%
29	Equity Return Authorized			9.86%		9.86%	9.86%	9.86%	9.86%	9.86%	9.86%	9.86%	9.86%	9.86%	9.86%
30	Debt %			40%		40%	40%	40%	40%	40%	40%	40%	40%	40%	40%
31	Interest Rate			4.50%		4.50%	4.50%	4.50%	4.50%	4.50%	4.50%	4.50%	4.50%	4.50%	4.50%
32	Return on Investment Base			=(G28*G29)+(G30*G31)		7.72%	7.72%	7.72%	7.72%	7.72%	7.72%	7.72%	7.72%	7.72%	7.72%
33	Escalation Rate (Inflation)			1.85%		1.85%	1.85%	1.85%	1.85%	1.85%	1.85%	1.85%	1.85%	1.85%	1.85%
34	Cumulative Escalation					101.85%	103.73%	105.65%	107.61%	109.60%	111.63%	113.69%	115.79%	117.94%	120.12%
35	Depreciable Life (Years)			20.00		20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00
36	Straight Line Depreciation Rate			=1/G35		5.0%	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%
37															

A1	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P
	Line N	*Dollar Amounts in $Thousands*		Years:	0	1	2	3	4	5	6	7	8	9	10
	Tab:	**DRIVERS & ASSUMPTIONS**	FN	REF & FORMULAS		12/31/2016	12/31/2017	12/31/2018	12/31/2019	12/31/2020	12/31/2021	12/31/2022	12/31/2023	12/31/2024	12/31/2025
38	**Commodity Market Price Assumptions**														
39	**Natural Gas**														
40	Nymex Futures Contracts *[FOR REFERENCE ONLY]*					*$ 3.35*	*$ 3.51*	*$ 3.69*	*$ 3.90*	*$ 4.15*	*$ 4.40*	*$ 4.65*	*$ 4.89*	*$ 5.11*	*$ 5.34*
41	Ventyx Long Term Fcst					$ 2.86	$ 3.18	$ 3.49	$ 4.37	$ 5.49	$ 5.89	$ 6.34	$ 6.48	$ 6.59	$ 6.71
42	EIA Long Term Fcst					$ 3.82	$ 3.90	$ 4.09	$ 4.61	$ 5.07	$ 5.54	$ 5.79	$ 5.97	$ 6.25	$ 6.48
43	Average Forecasted Price			=AVERAGE(41:42)		$ 3.34	$ 3.54	$ 3.79	$ 4.49	$ 5.28	$ 5.72	$ 6.07	$ 6.22	$ 6.42	$ 6.59
44				INPUT											
45	Heat (BTU) Content Factor			105%		105%	105%	105%	105%	105%	105%	105%	105%	105%	105%
46				OPTION											
47	Gas Price			2		$ 3.34	$ 3.54	$ 3.79	$ 4.49	$ 5.28	$ 5.72	$ 6.07	$ 6.22	$ 6.42	$ 6.59
48	1	High	+5%	FLEX %		$ 3.51	$ 3.72	$ 3.98	$ 4.71	$ 5.54	$ 6.00	$ 6.37	$ 6.53	$ 6.74	$ 6.92
49	2	Base		5.00%		$ 3.34	$ 3.54	$ 3.79	$ 4.49	$ 5.28	$ 5.72	$ 6.07	$ 6.22	$ 6.42	$ 6.59
50	3	Low	-5%			$ 3.17	$ 3.36	$ 3.60	$ 4.27	$ 5.02	$ 5.43	$ 5.76	$ 5.91	$ 6.10	$ 6.26
51	**Tax Assumptions**														
52	Federal Tax Rate (Statutory)					35.0%	35.0%	35.0%	35.0%	35.0%	35.0%	35.0%	35.0%	35.0%	35.0%
53	State Tax Rate (Statutory)					4.6%	4.6%	4.6%	4.6%	4.6%	4.6%	4.6%	4.6%	4.6%	4.6%
54	Combined Tax Rate			=G52+(G53*(1-G52))		38.0%	38.0%	38.0%	38.0%	38.0%	38.0%	38.0%	38.0%	38.0%	38.0%
55	Tax Gross Up Rate			=1/(1-G54)		1.61	1.61	1.61	1.61	1.61	1.61	1.61	1.61	1.61	1.61
56	Amount of Capital to Intangible Drilling Cost Deduction					85%	85%	85%	85%	85%	85%	85%	85%	85%	85%
57	Amount of Capital to Depletable Leaseholds					5%	5%	5%	5%	5%	5%	5%	5%	5%	5%
58	Amount of Capital to Tangibles					10%	10%	10%	10%	10%	10%	10%	10%	10%	10%
59															
60	**Footnotes**														
61	(a1)	Depreciable capex includes water lines for drilling operations, roads and other facilities													

A1	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P
2	Line No.	*Dollar Amounts in $Thousands*		Years:	0	1	2	3	4	5	6	7	8	9	10
3	Tab:	**OUTPUTS**	FN	REF & FORMULAS		12/31/2016	12/31/2017	12/31/2018	12/31/2019	12/31/2020	12/31/2021	12/31/2022	12/31/2023	12/31/2024	12/31/2025
4	**Price per Mcf Comparison**														
5	COSGCO Price Calculation per MMBTU			='Financial Model'!H66		$ 5.26	$ 4.91	$ 4.73	$ 4.75	$ 4.78	$ 4.74	$ 4.69	$ 4.64	$ 4.61	$ 4.52
6	'16-'20 Simple Avg			=AVERAGE(G5:K5)	4.88										
7	'16-'25 Simple Avg			=AVERAGE(G5:Q5)	4.76										
8	Nat Gas Market Price Forecast per MMBTU			='Financial Model'!H67		$ 3.34	$ 3.54	$ 3.79	$ 4.49	$ 5.28	$ 5.72	$ 6.07	$ 6.22	$ 6.42	$ 6.59
9	'16-'20 Simple Avg			=AVERAGE(G8:K8)	4.09										
10	'16-'25 Simple Avg			=AVERAGE(G8:Q8)	5.15										
11															
12	Gas Volumes MMBTU			='Drivers&Assumptions'!G26		12,600,000	14,700,000	15,750,000	16,275,000	18,375,000	17,850,000	21,000,000	22,050,000	23,625,000	24,150,000
13															
14	**Net Present Value (NPV) Analysis-Base Case**		(a2)												
15	Cost of market purchases			=(G8*G12)/1000		42,104	52,041	59,638	73,069	97,006	102,014	127,397	137,231	151,737	159,192
16	Discount Rate			='Drivers&Assumptions'!G32	Mid-Year?	7.72%	7.72%	7.72%	7.72%	7.72%	7.72%	7.72%	7.72%	7.72%	7.72%
17	Discount Period			=IF($F$17="Y",G2-$F$2-0.5,G2-$F$2)	Y	0.50	1.50	2.50	3.50	4.50	5.50	6.50	7.50	8.50	9.50
18	Discount Factor			=1/((1+$G$16)^(G17))		0.96	0.89	0.83	0.77	0.72	0.66	0.62	0.57	0.53	0.49
19	Present Values of Market Purchase Costs			=G15*G18		40,568	46,550	49,525	56,332	69,428	67,782	78,584	78,587	80,670	78,570
20	Sum of Present Values			=SUM(G19:Q19)	646,597										
21	Cost of COSGCO pricing			=(G5*G12)/1000		66,239	72,127	74,459	77,280	87,859	84,538	98,445	102,289	108,844	109,172
22	Discount Factor			=G18		0.96	0.89	0.83	0.77	0.72	0.66	0.62	0.57	0.53	0.49
23	Present Values of COSGCO pricing			=G21*G22		63,822	64,517	61,833	59,578	62,882	56,171	60,726	58,577	57,866	53,883
24	Sum of Present Values			=SUM(G23:Q23)	599,855										
25	Delta Mkt v COSGCO = Hedge Cost/(Credit)			=G21-G15		24,134	20,086	14,821	4,211	(9,146)	(17,475)	(28,951)	(34,942)	(42,893)	(50,020)
26	Discount Factor			=G18		0.96	0.89	0.83	0.77	0.72	0.66	0.62	0.57	0.53	0.49
27	Present Values of Hedge Cost/(Credit)			=G25*G26		23,254	17,967	12,308	3,247	(6,546)	(11,611)	(17,859)	(20,010)	(22,804)	(24,688)
28	Sum of Present Values			=SUM(G27:Q27)	(46,742)										
29															
30	**NPV Sensitivities:**				10YEAR	NPV Customer (Savings)/Cost		Commodity Price							
31								Low - 5%	Base	High + 5%					
32						Commodity Production	Low - 5%	15,681	(25,061)	(66,160)					
33							Base	(3,629)	(46,742)	(89,265)					
34							High + 5%	(23,486)	(68,613)	(111,683)					
35															
36								Commodity Price							
37								Low - 5%	Base	High + 5%					
38							High + 5%	16,817	(25,858)	(68,971)					
39						Capital Spend	Base	(3,629)	(46,742)	(89,265)					
40							Low - 5%	(24,514)	(67,627)	(108,422)					
41															
42															
43															
44															
45															
46	**Footnotes**														
47	(a2)	NPV analysis is focused on model years presented (i.e. '16-'25 or 10 year NPV) for purposes of the immediate analysis; COSGCO program contemplates longer term, life of well, NPV analysis													

A1	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q
	Line No.		*Dollar Amounts in $Thousands*		Years:	0	1	2	3	4	5	6	7	8	9	10
	Tab: FINANCIAL MODEL			FN	REF & FORMULAS		12/31/2016	12/31/2017	12/31/2018	12/31/2019	12/31/2020	12/31/2021	12/31/2022	12/31/2023	12/31/2024	12/31/2025
4	**COSGCO Gas Production**															
5		Production MMBTU		(a3)	='Drivers&Assumptions'!G26	Allocation %	12,600,000	14,700,000	15,750,000	16,275,000	18,375,000	17,850,000	21,000,000	22,050,000	23,625,000	24,150,000
6			Iowa Participation	(a4)	=H5*$G$6	24%	3,002,479	3,502,893	3,753,099	3,878,202	4,378,616	4,253,512	5,004,132	5,254,339	5,629,649	5,754,752
7			Kansas Participation		=H5*$G$7	18%	2,256,198	2,632,231	2,820,248	2,914,256	3,290,289	3,196,281	3,760,331	3,948,347	4,230,372	4,324,380
8			Nebraska Participation		=H5*$G$8	22%	2,811,570	3,280,165	3,514,463	3,631,612	4,100,207	3,983,058	4,685,950	4,920,248	5,271,694	5,388,843
9			Colorado Participation		=H5*$G$9	26%	3,297,521	3,847,107	4,121,901	4,259,298	4,808,884	4,671,488	5,495,868	5,770,661	6,182,851	6,320,248
10			Wyoming Participation		=H5*$G$10	9%	1,128,099	1,316,116	1,410,124	1,457,128	1,645,145	1,598,140	1,880,165	1,974,174	2,115,186	2,162,190
11			South Dakota Participation		=H5*$G$11	1%	104,132	121,488	130,165	134,504	151,860	147,521	173,554	182,231	195,248	199,587
12			% of Paticipating State's Firm Demand		=H5/$F$170	100%	17%	20%	22%	22%	25%	25%	29%	30%	33%	33%
13																
14	**COSGCO Stand-Alone Income Statement**															
15			Revenues		=(H5*H68)/1000+H160		$ 55,968	$ 76,720	$ 90,092	$ 110,305	$ 141,419	$ 149,763	$ 178,102	$ 190,839	$ 210,200	$ 221,233
16			Expenses		=H86+H89+((H15-H86-H89)*H102)		61,460	77,410	86,504	99,323	118,418	121,232	141,584	149,850	163,929	170,636
17			Net Income/(Loss)		=H15-H16		(5,492)	(690)	3,588	10,981	23,001	28,531	36,518	40,989	46,271	50,598
18																
19	**ROE Sharing Band Determination**															
20			Equity Deployed		=H36*H40		106,895	132,766	144,210	153,412	159,578	162,949	170,979	177,950	181,193	180,342
21			ROE Actual		=H17/H20		-5.14%	-0.52%	2.49%	7.16%	14.41%	17.51%	21.36%	23.03%	25.54%	28.06%
22			ROE Authorized BEFORE Sharing		9.86%		9.86%	9.86%	9.86%	9.86%	9.86%	9.86%	9.86%	9.86%	9.86%	9.86%
23			ROE Authorized AFTER Sharing		=IF(H21>H22,MIN(H22+0.01,H21),MAX(H22-0.01,H21))		8.86%	8.86%	8.86%	8.86%	10.86%	10.86%	10.86%	10.86%	10.86%	10.86%
24			Net Income Shortfall/(Excess)		=(H20*H23)-H17		14,963	12,453	9,189	2,611	(5,671)	(10,835)	(17,950)	(21,664)	(26,594)	(31,012)
25			Times: Tax Gross Up		='Drivers&Assumptions'!G55		1.61	1.61	1.61	1.61	1.61	1.61	1.61	1.61	1.61	1.61
26			Hedge Cost/(Credit)		=H24*H25		$ 24,134	$ 20,086	$ 14,821	$ 4,211	$ (9,146)	$ (17,475)	$ (28,951)	$ (34,942)	$ (42,893)	$ (50,020)
27																

A1	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q
	Line No.		*Dollar Amounts in $Thousands*		Years:	0	1	2	3	4	5	6	7	8	9	10
	Tab: FINANCIAL MODEL			FN	REF & FORMULAS		12/31/2016	12/31/2017	12/31/2018	12/31/2019	12/31/2020	12/31/2021	12/31/2022	12/31/2023	12/31/2024	12/31/2025
28	**Investment Base**															
29		Investment Base Rollforward														
30			Beginning Balance		=G34	$ -	$ 148,500	$ 207,816	$ 234,736	$ 245,963	$ 265,411	$ 266,515	$ 276,647	$ 293,282	$ 299,884	$ 304,094
31			Plus: Capital Expenditures		='Drivers&Assumptions'!G14	148,500	90,925	64,757	51,374	64,565	52,059	60,278	71,626	62,529	63,686	52,349
32			Less: Depr, Depl & Amort ("DD&A")		=-H134	-	(25,804)	(30,627)	(32,317)	(36,785)	(40,334)	(39,299)	(43,610)	(44,082)	(47,416)	(47,393)
33			+/- Change in Accum Def Inc Tax ("ADIT")		=-H104	-	(5,805)	(7,210)	(7,831)	(8,331)	(10,622)	(10,846)	(11,381)	(11,845)	(12,060)	(12,004)
34			Ending Balance		=H30+SUM(H31:H33)	148,500	207,816	234,736	245,963	265,411	266,515	276,647	293,282	299,884	304,094	297,046
35																
36			Average Balance		=(G34+H34)/2		$ 178,158	$ 221,276	$ 240,349	$ 255,687	$ 265,963	$ 271,581	$ 284,965	$ 296,583	$ 301,989	$ 300,570
37																
38	**Revenue Requirement**															
39		Return On Investment														
40			Equity %		='Drivers&Assumptions'!G28		60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%
41			Equity Return Authorized	(b)	='Drivers&Assumptions'!G29		9.86%	9.86%	9.86%	9.86%	9.86%	9.86%	9.86%	9.86%	9.86%	9.86%
42			Debt %		='Drivers&Assumptions'!G30		40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%
43			Interest Rate		='Drivers&Assumptions'!G31		4.50%	4.50%	4.50%	4.50%	4.50%	4.50%	4.50%	4.50%	4.50%	4.50%
44			Return on Investment Base ("ROIB")		=(H40*H41)+(H42*H43)		7.72%	7.72%	7.72%	7.72%	7.72%	7.72%	7.72%	7.72%	7.72%	7.72%
45																
46			Authorized Return		=H36*H44		$ 13,747	$ 17,074	$ 18,545	$ 19,729	$ 20,522	$ 20,955	$ 21,988	$ 22,884	$ 23,301	$ 23,192
47																
48		Expense Recovery														
49			Depreciation, Depletion & Amort ("DD&A")		=-H32		$ 25,804	$ 30,627	$ 32,317	$ 36,785	$ 40,334	$ 39,299	$ 43,610	$ 44,082	$ 47,416	$ 47,393
50			Lease Operating Expenses	(c)			3,056	3,423	3,804	4,197	4,384	4,465	4,661	4,863	5,543	6,126
51			Production Taxes	(d)			3,363	4,696	5,616	7,003	9,145	9,863	11,947	13,038	14,626	15,679
52			Program Administrative Fees	(e)			255	259	264	269	274	279	284	289	295	300
53			Gathering & Processing Expenses	(f)			25,200	30,498	33,281	35,026	40,278	39,851	47,750	51,065	55,725	58,017
54			Marketing/Scheduling/Takeaway Pipeline Capacity Fees	(g)			1,906	2,272	2,584	2,558	2,927	2,867	3,546	3,734	4,169	4,296
55			General & Administrative ("G&A")	(h)			2,037	2,075	2,113	2,152	2,192	2,233	2,274	2,316	2,359	2,402
56																
57			Total Operating Expenses		=SUM(H49:H56)		61,620	73,850	79,979	87,991	99,534	98,857	114,073	119,389	130,133	134,214
58			Income Taxes		=H36*H40*H41*H102*H25		6,460	8,023	8,715	9,271	9,644	9,847	10,333	10,754	10,950	10,898
59			Total Recoverable Expenses		=H57+H58		68,080	81,874	88,694	97,262	109,177	108,704	124,405	130,143	141,083	145,112
60																
61		Gross Revenue Requirement (Before Sharing)			=H46+H59		$ 81,826	$ 98,947	$ 107,239	$ 116,990	$ 129,699	$ 129,659	$ 146,393	$ 153,027	$ 164,385	$ 168,304
62		Revenue Credit-Oil and Nat Gas Liquid Sales Proceeds			=-H160		(13,864)	(24,679)	(30,454)	(37,236)	(44,413)	(47,749)	(50,706)	(53,608)	(58,463)	(62,042)
63		ROE Adjustment (+/-1% Max/Min)			=H36*H40*(H23-H41)*H25		(1,724)	(2,141)	(2,326)	(2,474)	2,574	2,628	2,758	2,870	2,922	2,909
64		Net Revenue Requirement			=SUM(H61:H63)		66,239	72,127	74,459	77,280	87,859	84,538	98,445	102,289	108,844	109,172
65																
66	**Gas Price Per Mcf**															
67		COSGCO Price Calculation per MMBTU			=H64/(H5/1000)		$ 5.26	$ 4.91	$ 4.73	$ 4.75	$ 4.78	$ 4.74	$ 4.69	$ 4.64	$ 4.61	$ 4.52
68		Nat Gas Market Price Forecast per MMBTU		(i)	='Drivers&Assumptions'!G47		$ 3.34	$ 3.54	$ 3.79	$ 4.49	$ 5.28	$ 5.72	$ 6.07	$ 6.22	$ 6.42	$ 6.59

A1	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q
	Line No.		*Dollar Amounts in $Thousands*		Years:	0	1	2	3	4	5	6	7	8	9	10
	Tab: FINANCIAL MODEL			FN	REF & FORMULAS		12/31/2016	12/31/2017	12/31/2018	12/31/2019	12/31/2020	12/31/2021	12/31/2022	12/31/2023	12/31/2024	12/31/2025
69																
70	**Income Statement (COSGCO + BHUH HEDGE)**															
71		Revenues														
72			Gas Market Sales Revenue		=(H5*H68)/1000		$ 42,104	$ 52,041	$ 59,638	$ 73,069	$ 97,006	$ 102,014	$ 127,397	$ 137,231	$ 151,737	$ 159,192
73			Oil & NGL Market Sales Revenue		=-H62		13,864	24,679	30,454	37,236	44,413	47,749	50,706	53,608	58,463	62,042
74			Hedge Cost/(Credit)		=H26		24,134	20,086	14,821	4,211	(9,146)	(17,475)	(28,951)	(34,942)	(42,893)	(50,020)
75			Total Revenues		=SUM(H72:H74)		80,102	96,806	104,913	114,516	132,273	132,288	149,151	155,897	167,307	171,213
76																
77		Expenses														
78			DD&A		=H49		$ 25,804	$ 30,627	$ 32,317	$ 36,785	$ 40,334	$ 39,299	$ 43,610	$ 44,082	$ 47,416	$ 47,393
79			Lease Operating Expenses		=H50		3,056	3,423	3,804	4,197	4,384	4,465	4,661	4,863	5,543	6,126
80			Production Taxes		=H51		3,363	4,696	5,616	7,003	9,145	9,863	11,947	13,038	14,626	15,679
81			Program Administrative Fees		=H52		255	259	264	269	274	279	284	289	295	300
82			Gathering & Processing Expenses		=H53		25,200	30,498	33,281	35,026	40,278	39,851	47,750	51,065	55,725	58,017
83			Marketing/Scheduling/Takeaway Pipeline Capacity Fees		=H54		1,906	2,272	2,584	2,558	2,927	2,867	3,546	3,734	4,169	4,296
84			G&A		=H55		2,037	2,075	2,113	2,152	2,192	2,233	2,274	2,316	2,359	2,402
85																
86			Total Operating Expenses		=SUM(H78:H84)		61,620	73,850	79,979	87,991	99,534	98,857	114,073	119,389	130,133	134,214
87																
88			Earnings Before Interest & Taxes		=H75-H86		18,482	22,956	24,934	26,525	32,739	33,431	35,078	36,508	37,174	36,999
89			Interest		=H36*H42*H43		3,207	3,983	4,326	4,602	4,787	4,888	5,129	5,338	5,436	5,410
90			Earnings Before Tax		=H88-H89		15,276	18,973	20,608	21,923	27,952	28,542	29,949	31,170	31,738	31,589
91			Taxes		=H90*H102		5,805	7,210	7,831	8,331	10,622	10,846	11,381	11,845	12,060	12,004
92			Net Income		=H90-H91		9,471	11,763	12,777	13,592	17,330	17,696	18,568	19,325	19,678	19,585
93			ACTUAL ROE		=H92/(H36*H40)		8.86%	8.86%	8.86%	8.86%	10.86%	10.86%	10.86%	10.86%	10.86%	10.86%
94	**Tax Reconciliation**															
95		Earnings Before Tax			=H90		$ 15,276	$ 18,973	$ 20,608	$ 21,923	$ 27,952	$ 28,542	$ 29,949	$ 31,170	$ 31,738	$ 31,589
96		Plus: Book Depreciation/Depletion			=H78		25,804	30,627	32,317	36,785	40,334	39,299	43,610	44,082	47,416	47,393
97		Less: Tax DD&A			=-H142		(198,436)	(61,620)	(53,017)	(70,258)	(59,060)	(65,414)	(75,281)	(66,603)	(67,050)	(56,881)
98		Taxable Income/(Loss) BF NOL			=SUM(H95:H97)		(157,356)	(12,020)	(92)	(11,550)	9,226	2,427	(1,721)	8,649	12,104	22,101
99		NOL Generated/(Used)			=-H98		157,356	12,020	92	11,550	(9,226)	(2,427)	1,721	(8,649)	(12,104)	(22,101)
100		NOL Carryforward Balance			=G100+H99		157,356	169,376	169,468	181,018	171,793	169,365	171,087	162,437	150,333	128,232
101		Taxable Income After NOL			=H98+H99		-	-	-	-	-	-	-	-	-	-
102		Fed & State Combined Tax Rate			='Drivers&Assumptions'!G54		38.0%	38.0%	38.0%	38.0%	38.0%	38.0%	38.0%	38.0%	38.0%	38.0%
103		Current Tax			=H101*H102		-	-	-	-	-	-	-	-	-	-
104		Deferred Tax			=H91-H103		5,805	7,210	7,831	8,331	10,622	10,846	11,381	11,845	12,060	12,004
105																

A1	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q
	Line No.		*Dollar Amounts in $Thousands*		Years:	0	1	2	3	4	5	6	7	8	9	10
	Tab: FINANCIAL MODEL			FN	REF & FORMULAS		12/31/2016	12/31/2017	12/31/2018	12/31/2019	12/31/2020	12/31/2021	12/31/2022	12/31/2023	12/31/2024	12/31/2025
106	**Depreciation, Depletion & Amortization (DD&A) Calculations**															
107		Capital Costs for Depletion														
108		Depletion Pool														
109			Beginning of Year Reserves		='Drivers&Assumptions'!G87		125,000,000	150,000,000	165,000,000	170,000,000	185,000,000	200,000,000	225,000,000	245,000,000	255,000,000	265,000,000
110			Plus: Reserve Additions		=H112-H111-H109		39,130,000	32,480,000	23,960,000	34,850,000	37,510,000	47,160,000	45,250,000	36,340,000	38,050,000	38,670,000
111			Less: Annual Production (Mcfe)		='Drivers&Assumptions'!G80		(14,130,000)	(17,480,000)	(18,960,000)	(19,850,000)	(22,510,000)	(22,160,000)	(25,250,000)	(26,340,000)	(28,050,000)	(28,670,000)
112			Total End of Yr Reserves (Mcfe)		=I109		150,000,000	165,000,000	170,000,000	185,000,000	200,000,000	225,000,000	245,000,000	255,000,000	265,000,000	275,000,000
113			Depletion Factor		=-H111/H109		11.30%	11.65%	11.49%	11.68%	12.17%	11.08%	11.22%	10.75%	11.00%	10.82%
114			Depletable Pool		=H118+H119		$ 219,425	$ 250,378	$ 265,575	$ 299,623	$ 316,697	$ 338,441	$ 372,567	$ 393,286	$ 414,689	$ 421,422
115			Depletion Expense		=H114*H113		24,804	29,177	30,517	34,985	38,534	37,499	41,810	42,282	45,616	45,593
116																
117		Depletion Pool Rollforward														
118			Beg Balance Depletable Pool		=G121	-	$ 141,000	$ 194,621	$ 221,201	$ 235,058	$ 264,637	$ 278,162	$ 300,941	$ 330,757	$ 351,003	$ 369,073
119			Add: Capex to Depletion Pool		='Drivers&Assumptions'!G12	141,000	78,425	55,757	44,374	64,565	52,059	60,278	71,626	62,529	63,686	52,349
120			Less: Depletion		=-H115	-	(24,804)	(29,177)	(30,517)	(34,985)	(38,534)	(37,499)	(41,810)	(42,282)	(45,616)	(45,593)
121			End Balance Depletable Pool		=SUM(H118:H120)	141,000	194,621	221,201	235,058	264,637	278,162	300,941	330,757	351,003	369,073	375,829
122																
123		Capital Costs for Depreciation														
124			Depreciable Basis		=G130+H130		$ 20,000	$ 29,000	$ 36,000	$ 36,000	$ 36,000	$ 36,000	$ 36,000	$ 36,000	$ 36,000	$ 36,000
125			Depreciation Rate		='Drivers&Assumptions'!G58		5.0%	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%
126			Depreciation Expense		=H124*H125		1,000	1,450	1,800	1,800	1,800	1,800	1,800	1,800	1,800	1,800
127																
128		Depreciable Basis Rollforward														
129			Beg Balance Depreciable Basis		=G132		$ 7,500	$ 19,000	$ 26,550	$ 31,750	$ 29,950	$ 28,150	$ 26,350	$ 24,550	$ 22,750	$ 20,950
130			Add: Capex		='Drivers&Assumptions'!G13	7,500	12,500	9,000	7,000	-	-	-	-	-	-	-
131			Less: Depreciation		=-H126	-	(1,000)	(1,450)	(1,800)	(1,800)	(1,800)	(1,800)	(1,800)	(1,800)	(1,800)	(1,800)
132			End Balance Depreciable Basis		=SUM(H129:H131)	7,500	19,000	26,550	31,750	29,950	28,150	26,350	24,550	22,750	20,950	19,150
133																
134			Total DD&A		=H115+H126		$ 25,804	$ 30,627	$ 32,317	$ 36,785	$ 40,334	$ 39,299	$ 43,610	$ 44,082	$ 47,416	$ 47,393
135																
136		Tax DD&A														
137			Depletable Pool (Tax)		=G137+G147+H147		$ 23,921	$ 26,709	$ 28,928	$ 32,156	$ 34,759	$ 37,773	$ 41,354	$ 44,481	$ 47,665	$ 50,282
138			Depletion Factor		=H113		11.30%	11.65%	11.49%	11.68%	12.17%	11.08%	11.22%	10.75%	11.00%	10.82%
139			Tax Depletion Deduction		=H137*H138		2,704	3,112	3,324	3,755	4,229	4,185	4,641	4,782	5,243	5,440
140			Intangible Drilling Cost Deduction		=H146+G146		187,661	47,394	37,718	54,880	44,250	51,236	60,882	53,150	54,133	44,497
141			Tax Depreciation				8,071	11,114	11,975	11,624	10,580	9,992	9,758	8,671	7,674	6,945
142			Total Tax DD&A		=SUM(H139:H141)		198,436	61,620	53,017	70,258	59,060	65,414	75,281	66,603	67,050	56,881
143																
144		Tax Basis Rollforward														
145			Beg Balance Tax Basis		=G150		$ 148,500	$ 40,989	$ 44,126	$ 42,483	$ 36,790	$ 29,789	$ 24,653	$ 20,998	$ 16,924	$ 13,560
146			Add: Drilling Capex		=H119*'Drivers&Assumptions'!G56	121,000	66,661	47,394	37,718	54,880	44,250	51,236	60,882	53,150	54,133	44,497
147			Add: Depletable Capex		=H119*'Drivers&Assumptions'!G57	20,000	3,921	2,788	2,219	3,228	2,603	3,014	3,581	3,126	3,184	2,617
148			Add: Depreciable Capex		=(H119*'Drivers&Assumptions'!G58)+H130	7,500	20,342	14,576	11,437	6,456	5,206	6,028	7,163	6,253	6,369	5,235
149			Less: Tax DD&A		=-H142	-	(198,436)	(61,620)	(53,017)	(70,258)	(59,060)	(65,414)	(75,281)	(66,603)	(67,050)	(56,881)

A1	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q
	Line No.		*Dollar Amounts in $Thousands*		Years:	0	1	2	3	4	5	6	7	8	9	10
	Tab: FINANCIAL MODEL			FN	REF & FORMULAS		12/31/2016	12/31/2017	12/31/2018	12/31/2019	12/31/2020	12/31/2021	12/31/2022	12/31/2023	12/31/2024	12/31/2025
150			End Balance Tax Basis		=SUM(H145:H149)	148,500	40,989	44,126	42,483	36,790	29,789	24,653	20,998	16,924	13,560	9,028

A1	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q
	Line No.		*Dollar Amounts in $Thousands*		Years:	0	1	2	3	4	5	6	7	8	9	10
	Tab: FINANCIAL MODEL			FN	REF & FORMULAS		12/31/2016	12/31/2017	12/31/2018	12/31/2019	12/31/2020	12/31/2021	12/31/2022	12/31/2023	12/31/2024	12/31/2025
151																
152	**Liquids Credit Determination**															
153		Production														
154			Net bbl Oil				25,000	45,000	60,000	110,000	120,000	125,000	130,000	130,000	145,000	145,000
155			Oil Price Forecast				$ 67.14	$ 72.75	$ 78.09	$ 83.07	$ 86.53	$ 90.22	$ 93.94	$ 97.83	$ 101.85	$ 106.05
156			Oil Revenue		=(H154*H155)/1000		$ 1,678	$ 3,274	$ 4,685	$ 9,138	$ 10,384	$ 11,278	$ 12,213	$ 12,717	$ 14,768	$ 15,378
157			Net NGL Bbl				330,000	535,000	600,000	615,000	715,000	735,000	745,000	760,000	780,000	800,000
158			NGL Price Forecast				$ 36.92	$ 40.01	$ 42.95	$ 45.69	$ 47.59	$ 49.62	$ 51.67	$ 53.80	$ 56.02	$ 58.33
159			NGL Revenue		=(H157*H158)/1000		$ 12,185	$ 21,406	$ 25,769	$ 28,098	$ 34,029	$ 36,472	$ 38,493	$ 40,891	$ 43,694	$ 46,664
160		Total Liquids Revenue ($ Thousands)			=(H156+H159)		$ 13,864	$ 24,679	$ 30,454	$ 37,236	$ 44,413	$ 47,749	$ 50,706	$ 53,608	$ 58,463	$ 62,042
161																
162	**Footnotes**															
163		(a3)	Hydrocarbon production and reserves based on assumed proven developed producing (PDP) wells and supplemental future horizontal wells drilled in established basin; gas content varies but includes both dry gas and liquid-rich production areas													
164		(a4)	State		Annual Demand	Allocation%										
165			Iowa		17,300,000	24%										
166			Kansas		13,000,000	18%										
167			Nebraska		16,200,000	22%										
168			Colorado		19,000,000	26%										
169			Wyoming		6,500,000	9%										
170			South Dakota		600,000	1%										
171			Total		72,600,000	100%										
172		(b)	Per 2014 Regulatory Research Associates "Major Rate Case Decisions--Calendar 2014" Report dated 1/15/15													
173		(c)	Based on dollar per well month assumption for representative field													
174		(d)	5.75% production tax rate assumed													
175		(e)	Costs incurred for Hydrocarbon & Accounting Monitor included in this category													
176		(f)	Fees to gas processing plant to extract natural gas liquids ("NGLs") and refine/treat gas to pipeline quality specifications													
177		(g)	Fees to gas marketer to facilitate market sales and fees to interstate or intrastate pipelines for takeaway capacity to move processed gas to market													
178		(h)	Program administration fee to gas field operator													
179		(i)	Long term forecast for gas price = average EIA & Ventyx Spring 2015 Reference Case in nominal dollars (i.e. escalated for inflation)													
180		(j)	Long term forecast for oil price = average of base case for WTI Oil from EIA & Ventyx Spring 2015 Reference Case in nominal dollars (i.e. escalated for inflation)													
181		(k)	Forecast for NGL price = 58% of Oil based upon historical correlation to WTI in nominal dollars (i.e. escalated for inflation)													
182		(l)	Capital outlay for drilling and completion of horizontal wells necessary to ramp up production to target volumes with additional wells drilled thereafter to maintain target production levels													
183		(m)	Capital outlay for infrastructure associated with drilling field locations; tangible equipment that is depreciated (e.g. water lines, access roads, compressor stations, etc.)													
184		(n)	Assumes tax rules allowing for "percentage depletion" which is based on a percentage of sales regardless of tax basis do not provide incremental benefit; thus, tax depletion rate held equal to book depletion rate													
185		(o)	Assumed to qualify for 7 year MACRS tax depreciation schedules													

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