EXHIBIT 7
Direct Testimony and Exhibits
T. AARON CARR

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

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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 Power, Inc. (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 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/Board 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 COSG PROGRAM?

A. Yes. As is explained in greater detail below, as part of its application and the COSG Program, the Company is proposing that a series of reviews, guidelines, and independent professional monitors be approved and implemented to provide regular oversight opportunities. The COSG Agreement is included as Exhibit 3.1 to the Direct Testimony of Ivan Vancas. First, 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. Second, 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. COMMISSION REVIEW

Q. DOES THE COSG PROGRAM PROVIDE THE COMMISSION WITH ONGOING OPPORTUNITIES TO ADDRESS CONCERNS? IF SO, CAN YOU EXPLAIN SPECIFICALLY WHEN SUCH OPPORTUNITIES WOULD ARISE?

A. Yes. As noted, 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/Board 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 Christopher 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 7.1, 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 Christopher 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 Fuel and Purchased Power Adjustment ("FPPA") tariff 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. 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 FPPA filings. Furthermore, the Commission/Board 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/Board 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 7.2.

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. CONCLUSION

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.