Direct Testimony
Christopher J. Kilpatrick

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Exhibits

I. INTRODUCTION AND QUALIFICATIONS

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Christopher J. Kilpatrick, 625 Ninth Street, P.O. Box 1400, Rapid City, South Dakota 57701.

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

A. I am employed by Black Hills Utility Holdings, Inc. ("BHUH"), a wholly-owned subsidiary of Black Hills Corporation ("BHC"), as Director of Regulatory Services.

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 am a graduate of Mount Marty College in Yankton, South Dakota, with a Bachelor of Arts Degree in Accounting. I am a Certified Public Accountant, a Chartered Global Management Accountant, a member of the American Institute of Certified Public Accountants, and a member of the South Dakota CPA Society. My work experience includes working for two public accounting firms from 1994 through 1999. The first was Wohlenberg, Ritzman, and Co., located in Yankton, South Dakota, and the second was Ketel Thorstenson, LLP, located in Rapid City, South Dakota. I began my career with BHC in January 2000 in the internal audit department. In August 2003, I became the controller of Black Hills FiberCom until February 2005 when I accepted the position of Director of Accounting – Retail Operations. In August 2008, I became Director of Rates. In 2011, I accepted an expanded role, responsible for both electric rates and resource planning. In 2013, BHC reorganized its Resource Planning department, and I am now the Director of Regulatory.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THIS COMMISSION?

A. No.

II. PURPOSE OF TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY?

A. My testimony explains and supports the Company's application by describing and addressing various accounting and regulatory issues associated with the proposed Cost of Service Gas Program (the "COSG Program") including: how "Hedge Credits" and "Hedge Costs" will be calculated under the COSG Program; how revenues, expenses, and return on equity will be calculated; how forecast and actual costs, and ultimately Hedge Credits and Hedge Costs, will be trued-up; and how the Company's Gas Cost Adjustment "GCA" tariff sheets will be modified in light of the COSG Program.

III. GENERAL OVERVIEW OF ACCOUNTING AND REGULATORY TREATMENT

Q. CAN YOU PROVIDE AN OVERVIEW OF HOW THE COSG PROGRAM WILL BE MANAGED FROM AN ACCOUNTING AND REGULATORY STANDPOINT?

A. Yes. The accounting for the COSG Program will commence with COSGCO (the entity that would acquire the gas reserve interests) in accordance with the COSG Agreement, and will include the determination of revenues, expenses, assets and liabilities included in the COSG Program. The financial results from COSGCO's operations (including its revenues from the market sale of its gas and other hydrocarbons and its expenses from production activities) will be forecast for six-month periods as described later in my testimony. These forecasts will be used to calculate whether customers will receive a Hedge Credit or pay a Hedge Cost each month. All other existing accounting processes and procedures will remain in place for the GCA, but will also include the projected Hedge Credits or Hedge Costs. After the end of each calendar year, COSGCO's actual financial results will be used to calculate the actual Hedge Credit or Hedge Cost for the calendar year, and any differences from the forecast amounts will be trued-up annually in a reconciliation. When customers receive Hedge Credits, their cost for gas will effectively be discounted from the market prices at the time, because the Hedge Credits will offset part of the Company's gas supply costs. If the Company incurs a Hedge Cost, it will pay an additional amount for the hedge and associated price stability benefits of the COSG Program.

Q. WHAT IS THE SOURCE OF THE ACCOUNTING GUIDANCE THAT WILL BE FOLLOWED FOR THE COSG PROGRAM?

A. ASC 932 - Accounting for Oil and Gas Exploration and ASC 980 (formerly known as FAS 71- Accounting for the Effects of Certain Types of Regulation) will be used to account for the effects of the COSG Agreement. Accounting for oil and gas production is a specialized and unique form of energy accounting. COSGCO will use the oil and gas industry standard chart of accounts to record all revenues, expenses, assets and liabilities. Attached as Exhibit CK-1 is a condensed chart of accounts that will be used for the COSG Program and how these accounts track back and forth from FERC to oil accounts and gas accounts.

Q. PLEASE DESCRIBE THE INTERNAL CONTROLS THAT WILL BE PUT IN PLACE TO ENSURE ACCURATE FINANCIAL REPORTING AND CALCULATIONS UNDER THE COSG AGREEMENT.

A. COSGCO will rely on a third party or BHEP to operate the wells to produce gas, either as a contract operator or as the operator under a joint operating agreement ("JOA"). Standard industry practice includes measures that substantially protect a non-operator. For example, under the standard industry form of JOA, COSGCO will (i) receive detailed monthly invoices for all costs (called "JIBs" by the industry, which is short for joint interest billings) calculated using the standard form accounting procedures (called the "COPAS" by the industry because it was developed by the Council of Petroleum Accountants Societies), and (ii) have audit rights. A sample JOA, including the COPAS, is attached as Exhibit JB-3 to the Direct Testimony of John Benton. Furthermore, COSGCO will utilize the expertise and experience of Black Hills Exploration and Production, Inc. ("BHEP") in oil and gas accounting. In addition to the protection provided by these standard industry procedures, there are also internal controls that will further ensure accurate financial accounting and calculations. COSGCO will be a company within Black Hills Corporation and will be subject to the same internal control standards as all other companies. These standards will be in compliance with Sarbanes Oxley and part of the annual audit currently performed by Deloitte and Touche.

Q. WILL A THIRD PARTY VERIFY THE FINANCIAL REPORTING AND HEDGE CALCULATIONS UNDER THE COSG AGREEMENT?

A. Yes. As required by Section 5.5 of the COSG Agreement, BHUH will provide the Company with an annual report containing COSGCO's financial statements, plus other information related to the calculation of Hedge Credits and Hedge Costs and the performance of the COSG Program. The independent Accounting Monitor will also provide an assurance report, which will assess whether BHUH's report is materially correct and consistent with the COSG Agreement. The Company will file the report and the Accounting Monitor's conclusions with the Commission as part of its next GCA filing.

IV. HEDGE CREDITS AND HEDGE COSTS

Q. WILL THERE BE A REVENUE REQUIREMENT CALCULATED UNDER THE COSG PROGRAM TO DETERMINE HEDGE CREDITS AND HEDGE COSTS?

A. In a matter of speaking, yes, although it is somewhat different than in a traditional regulatory setting. Hedge Credits and Hedge Costs will be calculated in accordance with the provisions and formulas set forth in the COSG Agreement, which effectively equate to a revenue requirement in a traditional regulatory setting. Consequently, there is a revenue requirement, including an allowed return on equity, imbedded in the calculation of Hedge Credits and Hedge Costs, which are based on COSGCO's financial performance.

Q. CAN YOU GENERALLY DESCRIBE HOW HEDGE CREDITS AND HEDGE COSTS WILL BE CALCULATED UNDER THE COSG PROGRAM?

A. Yes. In simple terms and as provided in the COSG Agreement, Hedge Credits and Hedge Costs will be calculated by first dividing "Net Income" (which will be calculated using the total revenues COSGCO receives from the market sales of its natural gas and other hydrocarbons to third parties, less operating expenses, interest expense, and income taxes) by "Invested Equity" (which will be 60% of "Investment Base," namely 60% of the net capital COSGCO has invested in the acquisition and development of the gas reserves).

The quotient is the "Actual ROE" under the COSG Agreement, which is used to calculate a Hedge Credit or Hedge Cost. To the extent the Actual ROE is more than 100 basis points greater than the "Allowed ROE" under the COSG Agreement, then the Company would receive a Hedge Credit from BHUH, which amount would flow through to the benefit of customers. On the other hand, to the extent the Actual ROE is less than the Allowed ROE by more than 100 basis points, then BHUH will assess a Hedge Cost to the Company. An illustration of this calculation is shown in Exhibit CK-2, pages 1 and 2.

Q. HOW WILL CUSTOMERS RECEIVE THE HEDGE CREDIT OR COST?

A. Customers will receive the Hedge Credit or Cost based on a six-month forecast. This forecast will be completed in November and May, respectively, for each six-month forecast period (i.e., January through June, and July through December). An example forecast for each period is shown in Exhibit CK-2, pages 3 and 4.

Q. PLEASE DESCRIBE EXHIBIT CK-2 PAGES 3 AND 4.

A. As described above, the starting point in determining a Hedge Credit or Cost is the financial performance of COSGCO. Pages 3 and 4 of Exhibit CK-2 show how the financial performance of COSGCO is reflected and how the resulting Hedge Credit or Cost is calculated. The forecast completed for each six-month period will also incorporate the 100 basis-point band as risk for BHUH. This is illustrated on pages 3 and 4 of Exhibit CK-2 on line 17 as a deadband in the calculation.

V. <u>INVESTMENT BASE</u>

Q. PLEASE EXPLAIN HOW INVESTMENT BASE WILL BE CALCULATED.

A. As provided in the COSG Agreement, Investment Base will consist of the average of the forecast capitalized costs at the end of each calendar month during each six-month forecast period to identify, acquire and develop reserve interests, less any accumulated depletion, depreciation, amortization, and net accumulated deferred taxes. Investment Base will include such components as: lease acquisition costs; capital investments; drilling, completion and tangible equipment costs; and compression, gathering and processing capital costs.

Q. IS THIS APPROACH SIMILAR TO THE APPROACH USED IN TYPICAL RATEMAKING CONTEXTS?

A. Yes it is. Under the COSG Program, the COSG Agreement allows the recovery of prudently-incurred expenses and a return on and a return of investment base in the same way that the Company typically recovers for prudently-incurred expenses and a return on and a return of rate base in other contexts.

Q. WOULD THE FORECASTS START WHEN THE COSG AGREEMENT IS SIGNED OR WHEN COSGCO ACTUALLY ACQUIRES ITS FIRST RESERVE INTEREST?

A. Forecasts would begin as close as practical to when COSGCO acquires its first reserve interest and gas is produced.

Q. WILL CONSTRUCTION WORK IN PROGRESS ("CWIP") BE INCLUDED IN THE INVESTMENT BASE?

A. No, CWIP will not be included in Investment Base. As an example, if a well is drilled, the capital costs to drill the well will be included in Investment Base when the well begins producing natural gas.

Q. WHEN WILL THE CAPITAL COSTS TO ACQUIRE INTERESTS IN GAS RESERVES BE INCLUDED IN INVESTMENT BASE?

A. The capital costs to acquire interests in gas reserves will be included in Investment Base as those interests are acquired. For example, when COSGCO acquires reserves, those reserves will be included as an asset on COSGCO's books and the acquisition cost would be included in the Investment Base used to calculate Hedge Credits and Hedge Costs from that point forward.

Q. IF COSGCO EARNS INTERESTS IN GAS RESERVES THROUGH DRILLING RATHER THAN PURCHASING INTERESTS, HOW WOULD THE INVESTMENT BASE BE DETERMINED?

A. If COSGCO earns interests in gas reserves through drilling under a joint development agreement, COSGCO's capital costs to drill the wells will be included in Investment Base as the wells are drilled and gas is produced, rather than when the joint development agreement is signed.

Q. WHAT ELSE WOULD BE INCLUDED IN INVESTMENT BASE?

A. Consistent with traditional ratemaking policies for both natural gas and electric utilities, payments for consultants, attorneys, and other costs to assess and complete a reserve transaction will be recorded to a Preliminary Natural Gas Survey and Investigation Charges Account. If the transaction is made, these costs will become part of Investment Base as described above. However, if the transaction is not made, these costs will not become part of Investment Base, but instead will be recovered through depletion accounting consistent with generally accepted accounting principles, FERC rules, and the COSG Agreement.

VI. NET INCOME UNDER THE COSG PROGRAM

Q. PLEASE EXPLAIN HOW NET INCOME WILL BE CALCULATED UNDER THE COSG PROGRAM.

A. As provided in the COSG Agreement, Net Income will be derived by calculating revenues minus expenses in accordance with generally accepted accounting principles and the COSG Agreement. Specifically, Net Income will be calculated based on the proceeds that COSGCO receives from the market sale of its share of production and hydrocarbons from the wells. That amount will be netted against the following: (i) COSGCO's operating expenses (e.g., lease operating expenses, processing, transportation and marketing costs, and accruals for future plugging, abandonment, and other anticipated asset retirement expenses), (ii) BHUH's implied interest expense reflecting the COSG Agreement's capital structure and cost of debt, and (iii) BHUH's income tax expense (both current and deferred). This calculation is shown in Exhibit CK-2 pages 1 and 2 based on a hypothetical example for illustrative purposes only.

Q. WHAT ARE THE OPERATING EXPENSES THAT WOULD BE INCLUDED IN THE CALCULATION OF NET INCOME (AND THE CALCULATION OF HEDGE CREDITS AND HEDGE COSTS)?

A. Generally, the same types of expenses recovered in the ratemaking process in the traditional natural gas and electric utility context will be used in calculating Net Income under the COSG Program. For example, COSGCO will incur direct costs for running the business, such as labor costs, associated benefits, and operation and maintenance costs. In addition, there may also be direct costs from Black Hills Service Company ("BHSC"), BHUH, and BHEP to the extent they render services to COSGCO.

Q. PLEASE EXPLAIN THE TYPE OF COSTS THAT COULD COME FROM THOSE OTHER COMPANIES.

A. Costs COSGCO incurs for the direct support and operation of the COSG Program will be directly charged by the respective supporting companies and will be added to the costs otherwise incurred by COSGCO to acquire, develop, and operate its reserves. For example, when BHEP provides direct consulting or other assistance to COSGCO, the costs for that support will be directly charged to COSGCO and included in the calculation of Net Income under the COSG Agreement. In addition, BHSC could provide such things as accounting services, legal support, and environmental services. The COSG Program will benefit from COSGCO's ability to leverage the existing expertise and systems of BHC.

Q. WILL COSGCO BE INCLUDED IN THE ALLOCATION OF COSTS UNDER BHUH'S OR BHSC'S COST ALLOCATION MANUALS?

A. No. As provided in Section 5.6 of the COSG Agreement, no indirect charges shall be allocated to BHUH's performance of the COSG Agreement under BHUH's or BHSC's cost allocation manuals. Because the COSG Program is a hedging program that flows through the Company's gas cost adjustment filings, it would be inconsistent with practice and inappropriate to allocate overhead charges to the COSG Program. Currently indirect costs are not allocated to the gas cost accounts as indirect costs are included in base rates and should remain in base rates to be reviewed through normal rate case procedures.

Q. WILL THE COST ALLOCATED MANUALS BE UPDATED TO REFLECT THIS APPROACH?

A. Yes. The cost allocated manuals will be updated when the COSG Program is approved.

Q. WHAT IS DEPLETION ACCOUNTING AND HOW IS IT APPLICABLE TO THE COSG PROGRAM?

A. Depletion accounting is used to account for the recovery of the capital costs associated with oil and gas reserves over time. Depletion is to hydrocarbon reserves as depreciation is to tangible equipment; both are means by which capital is expensed (i.e., recovered) over time. Generally Accepted Accounting Principles provide for two acceptable methods of accounting for depletion. The two methods are either Full Cost or Successful Efforts. The COSG Program will use the Full Cost Method, which is consistent with FERC guidance. Aaron Carr's Direct Testimony explains the benefits to customers of using the Full Cost Method. Standard depreciation principles would continue to dictate when other capital costs, such as the costs for equipment, are expensed.

Q. HOW DOES DEPLETION ACCOUNTING DIFFER FROM DEPRECIATION ACCOUNTING PRINCIPLES?

A. Each method is based on a systematic and rational manner to allocate the service value on an annual basis over the service life of the asset. However, depletion is based on the useful life of each well and the amount of production that will come from those wells. For a simple illustrative example, suppose a natural gas well costs $12,000,000 to drill and has an estimated asset retirement cost of $500,000. The well is expected to produce approximately 10 Bcf of natural gas over its life, which would result in a depletion expense of $1.20 per produced Mcf (i.e., [$12,000,000 + $500,000] ÷ 10 Bcf). Therefore for every Mcf produced from this hypothetical well, a corresponding expense of $1.20 would be recorded in the financial statements to reduce Investment Base. Depletion accounting becomes more complex as all the wells are analyzed collectively under the concept of depletion "pooling" to determine the depletion rate to use for all wells. Pursuant to ASC 932, for depletion purposes, COSGCO's capital investments in gas reserves will be aggregated at a reservoir or field level when they share common geological structural features. The reserve estimates used in calculating depletion will be updated annually and verified by the independent Hydrocarbon Monitor.

VII. <u>RETURN ON EQUITY</u>

Q. HOW WILL ACTUAL ROE BE CALCULATED UNDER THE COSG PROGRAM?

A. The COSG Agreement provides that Actual ROE will be calculated in much the same way it is under traditional rate making procedures. Net Income will be compared to Investment Base, and the quotient will be the Actual ROE.

Q. WHAT RETURN ON EQUITY WILL BE USED IN THE CALCULATION OF HEDGE COSTS AND HEDGE CREDITS?

A. The actual ROE earned under the COSG Program will be either the Allowed ROE or a risk-adjusted ROE within a range of minus 100 basis points to plus 100 basis points of the Allowed ROE, as discussed above.

Q. HOW IS THE ALLOWED ROE CALCULATED?

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

(ii) the average of the annual return on equity in all gas and electric utility rate cases for the prior calendar year, all as reported by Regulatory Research Associates." COSG Agreement, Article 1, at 2. Witness Adrian McKenzie discusses in detail how Allowed ROE is determined and explains why this approach is reasonable.

VIII. ANNUAL TRUE-UP OF HEDGE CREDITS AND COSTS

Q. WILL FORECAST HEDGE CREDITS AND HEDGE COSTS BE TRUED-UP BASED ON COSGCO'S ACTUAL PERFORMANCE?

A. Yes. Hedge Credits and Hedge Costs will be forecast before January 1 and July 1 for the following six-month period. Section 5.3 of the COSG Agreement provides for an annual reconciliation of those forecasts. No later than ninety days after the end of each calendar year, BHUH will reconcile the forecast Hedge Credits and Hedge Costs for the completed calendar year against the actual Hedge Credits and Hedge Costs for the completed calendar year, which will be calculated using COSGCO's actual performance during that calendar year and the actual Allowed ROE for that calendar year. (The report from Regulatory Research Associates used to determine the actual Allowed ROE for the completed year will not be available until mid- to late January.) See Exhibit CK-2, pages 5 and 6. Once this calculation is completed for the entire COSG Program, the Company's proportionate share of any necessary adjustment will be reflected in the next six-month period, which would be in approximately May of each year. This reconciliation process will ensure that the Company and its customers are receiving the actual benefits or paying the actual costs of the COSG Program and will be reflected in customer rates for six months beginning in July. See Exhibit CK-2, page 7 for an illustration of how this would work.

Q. ARE THERE MECHANISMS TO MITIGATE THE POSSIBILITY OF LARGE ANNUAL ADJUSTMENTS?

A. Yes. Utilizing six-month forecasts rather than annual forecasts is one mechanism to mitigate the possibility of large annual adjustments. The forecasts, particularly in the early years of the COSG Program, may also include an adjustment to reflect anticipated differences between the prior forecasts and actuals to date.

IX. TARIFF SHEETS

Q. WILL TARIFF SHEETS NEED TO BE MODIFIED TO IMPLEMENT THE COSG PROGRAM?

A. Yes. The Company's GCA adjustment clause tariff sheet will need to include a new variable as part of the formula for costs to be recovered from customers. The reason to make these changes in the Company's tariff sheet is to make sure all stakeholders are aware of how the COSG Program benefits and costs will flow into the adjustment clauses. This provides transparency and helps provide guidance on future audits of those adjustment clauses.

Q. WHAT SPECIFIC CHANGES WOULD BE MADE TO THE COMPANY'S TARIFF SHEET?

A. Attached as Exhibit CK-3 is a redline version of the Company's tariff sheet showing the modifications that would be necessary to incorporate the COSG Program.

X. CONCLUSION

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

FERC Account	Description	Quorum Account	Quorum Acct Description
101000	PLANT IN SERVICE	200-050	PROSPECTS - OTHER
101000	PLANT IN SERVICE	200-051	PROSPECTS
101000	PLANT IN SERVICE	200-055	LT PREPD WATER INFRASTRUCTURE
101000	PLANT IN SERVICE	200-060	CAPITALIZED INTEREST
101000	PLANT IN SERVICE	200-100	BROKERAGE SERVICES
101000	PLANT IN SERVICE	200-150	LEGAL SERVICES
101000	PLANT IN SERVICE	200-200	TITLE OPINIONS & ABSTRACTS
101000	PLANT IN SERVICE	200-250	FILING, RECORDING, AND ORIGINA
101000	PLANT IN SERVICE	200-300	LEASE BONUS
101000	PLANT IN SERVICE	200-350	DELAY RENTALS
101000	PLANT IN SERVICE	200-940	MISCELLANEOUS
101000	PLANT IN SERVICE	200-998	CONTRA - UNPROVED LEASEHOLD COSTS
101000	PLANT IN SERVICE	201-105	LOCATION/SITE/SURFACE COSTS
101000	PLANT IN SERVICE	201-110	PERMITS
101000	PLANT IN SERVICE	201-120	ENVIRONMENTAL COMPLIANCE
101000	PLANT IN SERVICE	201-130	TITLE COSTS
101000	PLANT IN SERVICE	201-140	SURVEYS
101000	PLANT IN SERVICE	201-180	LEGAL COST
101000	PLANT IN SERVICE	201-998	CONTRA - UNPROVED PRE-DRILL
101000	PLANT IN SERVICE	202-200	SEISMIC ACQUISITION/PURCHASE
101000	PLANT IN SERVICE	202-202	SEISMIC PERMITS/DAMAGES
101000	PLANT IN SERVICE	202-204	SEISMIC PERMIT AGENT
101000	PLANT IN SERVICE	205-100	BROKERAGE SERVICES
101000	PLANT IN SERVICE	205-150	LEGAL SERVICES
101000	PLANT IN SERVICE	205-200	TITLE OPINIONS & ABSTRACTS
101000	PLANT IN SERVICE	205-250	FILING, RECORDING, AND ORIGINA
101000	PLANT IN SERVICE	205-300	LEASE BONUS
101000	PLANT IN SERVICE	205-350	DELAY RENTALS
101000	PLANT IN SERVICE	205-400	MAPS, LOGS, REPRODUCTION
101000	PLANT IN SERVICE	205-450	SEISMIC
101000	PLANT IN SERVICE	205-500	LAND, G&G, EXPL COSTS
101000	PLANT IN SERVICE	205-940	MISCELLANEOUS
101000	PLANT IN SERVICE	205-950	NON-OPERATED LEASE ACQ COSTS
101000	PLANT IN SERVICE	205-980	EST - LEASE ACQ COSTS
101000	PLANT IN SERVICE	205-998	CONTRA - PROVED LEASEHOLD COSTS
101000	PLANT IN SERVICE	210-100	CASING HEAD & VALVES& ACCESSORIES
101000	PLANT IN SERVICE	210-105	CONDUCTOR CASING
101000	PLANT IN SERVICE	210-110	SURFACE CASING
101000	PLANT IN SERVICE	210-125	LINER, HANGER, CASING SPOOLS
101000	PLANT IN SERVICE	210-940	MISCELLANEOUS
101000	PLANT IN SERVICE	210-950	NON-OPERATED TANGIBLE DRILLING
101000	PLANT IN SERVICE	210-980	EST - TANGIBLE
101000	PLANT IN SERVICE	210-998	CONTRA - TANGIBLE DRLIING COSTS
101000	PLANT IN SERVICE	220-115	INTERMEDIATE CASING
101000	PLANT IN SERVICE	220-120	PRODUCTION CASING

FERC Account	Description	Quorum Account	Quorum Acct Description
101000	PLANT IN SERVICE	220-125	CASING LINER
101000	PLANT IN SERVICE	220-130	TUBING
101000	PLANT IN SERVICE	220-135	SUCKER RODS, GUIDES & ACCESSORIES
101000	PLANT IN SERVICE	220-145	DNHLE PMPS, PLNGRS, GS LFT VLV
101000	PLANT IN SERVICE	220-165	PACKER, BRIDGE PLUGS, ETC
101000	PLANT IN SERVICE	220-215	WELLHEAD EQUIPMENT & VALVES
101000	PLANT IN SERVICE	220-240	PRIME MOVER
101000	PLANT IN SERVICE	220-255	SURFACE ARTIFICIAL LIFT EQUIP
101000	PLANT IN SERVICE	220-300	TANKS & ACCESSORIES
101000	PLANT IN SERVICE	220-325	SEPARATOR, TREATOR, DEHYDRATOR
101000	PLANT IN SERVICE	220-340	FLOWLINES, VALVES, ETC (on wellsite)
101000	PLANT IN SERVICE	220-345	GAS GATHERING/SALES LINES (off wellsite)
101000	PLANT IN SERVICE	220-355	MEASUREMENT/ELECTRONIC EQUIPMENT
101000	PLANT IN SERVICE	220-360	BUILDINGS & HOUSINGS
101000	PLANT IN SERVICE	220-940	MISCELLANEOUS
101000	PLANT IN SERVICE	220-950	NON-OPERATED TANGIBLE COMPLET
101000	PLANT IN SERVICE	220-980	EST - TANGIBLE
101000	PLANT IN SERVICE	220-998	CONTRA - TANGIBLE COMPLETION COSTS
101000	PLANT IN SERVICE	230-100	DRILLING PERMIT, TITLE, BOND, LEGAL
101000	PLANT IN SERVICE	230-110	ENVIRONMENTAL COMPLIANCE
101000	PLANT IN SERVICE	230-120	SURFACE DAMAGES & ROW
101000	PLANT IN SERVICE	230-200	SURVEY & ARCHEOLOGY
101000	PLANT IN SERVICE	230-210	ROADS, LOCATION, PITS
101000	PLANT IN SERVICE	230-300	RIG MOB/DEMOB
101000	PLANT IN SERVICE	230-310	DRILLING CONTRACTOR
101000	PLANT IN SERVICE	230-360	WATER HAULING
101000	PLANT IN SERVICE	230-370	WATER MANAGEMENT
101000	PLANT IN SERVICE	230-390	DRILLING FLUIDS DISPOSAL
101000	PLANT IN SERVICE	230-400	CASING CREWS & LD MACHINE
101000	PLANT IN SERVICE	230-410	CEMENT & SERVICES
101000	PLANT IN SERVICE	230-500	SUBSURFACE EQUIP
101000	PLANT IN SERVICE	230-510	DIRECTIONAL DRLG TOOLS & SURVEY EQUIP RENTALS
101000	PLANT IN SERVICE	230-520	FISHING TOOLS
101000	PLANT IN SERVICE	230-530	SURFACE EQUIPMENT RENTALS
101000	PLANT IN SERVICE	230-540	MATERIALS & SUPPLIES
101000	PLANT IN SERVICE	230-700	OPEN HOLE LOGS
101000	PLANT IN SERVICE	230-710	MUD LOGGING UNIT
101000	PLANT IN SERVICE	230-720	DRILL STEM TESTS
101000	PLANT IN SERVICE	230-730	CORES & ANALYSIS
101000	PLANT IN SERVICE	230-900	OVERHEAD
101000	PLANT IN SERVICE	230-901	INSURANCE
101000	PLANT IN SERVICE	230-940	MISCELLANEOUS
101000	PLANT IN SERVICE	230-950	NON-OPERATED INTANGIBLE DRILL
101000	PLANT IN SERVICE	230-980	EST - INTANGIBLE
101000	PLANT IN SERVICE	230-998	CONTRA - INTANGIBLE DRLIING COSTS

FERC Account	Description	Quorum Account	Quorum Acct Description
101000	PLANT IN SERVICE	240-210	ROADS, LOCATION, PITS
101000	PLANT IN SERVICE	240-310	COMPLETION RIG & ACCESSORIES
101000	PLANT IN SERVICE	240-311	COIL RIG & ACCESSORIES
101000	PLANT IN SERVICE	240-320	ACID AND FRAC
101000	PLANT IN SERVICE	240-350	WATER SUPPLY
101000	PLANT IN SERVICE	240-360	WATER HAULING
101000	PLANT IN SERVICE	240-370	WATER MANAGEMENT
101000	PLANT IN SERVICE	240-390	FLUIDS DISPOSAL
101000	PLANT IN SERVICE	240-450	FRACING/ACIDIZING SERVICES
101000	PLANT IN SERVICE	240-455	COMPL FLUIDS, CHEMICALS, OIL
101000	PLANT IN SERVICE	240-500	SUBSURFACE EQUIP RENTALS
101000	PLANT IN SERVICE	240-530	SURFACE EQUIPMENT RENTALS
101000	PLANT IN SERVICE	240-535	HOUSING AND COMMUNICATIONS
101000	PLANT IN SERVICE	240-540	MATERIALS & SUPPLIES
101000	PLANT IN SERVICE	240-541	SITE ELECTRIFICATION (POWER LINES)
101000	PLANT IN SERVICE	240-750	MICROSEISMIC
101000	PLANT IN SERVICE	240-900	OVERHEAD
101000	PLANT IN SERVICE	240-901	INSURANCE
101000	PLANT IN SERVICE	240-940	MISCELLANEOUS
101000	PLANT IN SERVICE	240-950	NON-OPERATED INTANGIBLE COMPL
101000	PLANT IN SERVICE	240-980	EST - INTANGIBLE
101000	PLANT IN SERVICE	240-998	CONTRA - INTANGIBLE COMPLETION COSTS
101000	PLANT IN SERVICE	400-060	CAPITALIZED INTEREST
101000	PLANT IN SERVICE	400-210	LEASE ACQUISITION COSTS
101000	PLANT IN SERVICE	400-220	UNBILLED WELL COSTS
101000	PLANT IN SERVICE	400-300	TANGIBLE DRILLING
101000	PLANT IN SERVICE	400-310	TANGIBLE COMPLETION
101000	PLANT IN SERVICE	400-410	INTANGIBLE DRILLING
101000	PLANT IN SERVICE	400-510	INTANGIBLE COMPLETION
101000	PLANT IN SERVICE	400-590	NON-OPERATED LEASE ACQ COSTS
101000	PLANT IN SERVICE	400-600	NON-OPERATED TANGIBLE DRILLING
101000	PLANT IN SERVICE	400-610	NON-OPERATED TANGIBLE COMPLETE
101000	PLANT IN SERVICE	400-620	NON-OPERATED INTANGIBLE DRILL
101000	PLANT IN SERVICE	400-630	NON-OPERATED INTANGIBLE COMPL
101000	PLANT IN SERVICE	410-110	GEOLOGICAL & GEOPHYSICAL COSTS
101000	PLANT IN SERVICE	410-210	EXPLORATION DRYHOLE
101000	PLANT IN SERVICE	410-310	PLUGGING/ABANDONMENT COSTS
101000	PLANT IN SERVICE	410-410	ABANDONED LEASEHOLD COSTS
101000	PLANT IN SERVICE	410-420	ACQUISITION COSTS
101000	PLANT IN SERVICE	410-600	NON-OPERATED DRYHOLE
101000	PLANT IN SERVICE	410-610	NON-OPERATED PLUG/ABAND COSTS
101000	PLANT IN SERVICE	420-110	GEOLOGICAL & GEOPHYSICAL COSTS
101000	PLANT IN SERVICE	420-210	LEASE ACQUISITION COSTS
101000	PLANT IN SERVICE	500-005	OTHER PROPERTY - ESTIMATE
101000	PLANT IN SERVICE	500-105	FIELD OPERATING EQUIPMENT

FERC Account	Description	Quorum Account	Quorum Acct Description
101000	PLANT IN SERVICE	500-135	TRANSPORTATION EQUIP-FIELD
101000	PLANT IN SERVICE	500-137	TRANSPORTATION EQUIP-G&A
101000	PLANT IN SERVICE	500-138	TRANSPORTATION EQUIP BHMS
101000	PLANT IN SERVICE	500-145	OFFICE FURNITURE & EQUIP-FIELD
101000	PLANT IN SERVICE	500-147	OFFICE FURNITURE & EQUIP-G&A
101000	PLANT IN SERVICE	500-155	COMPUTER EQUIP & SOFTWAR-FIELD
101000	PLANT IN SERVICE	500-157	COMPUTER EQUIP & SOFTWARE-G&A
101000	PLANT IN SERVICE	500-158	EQUIPMENT - MIDSTREAM
101000	PLANT IN SERVICE	500-162	LAND
101000	PLANT IN SERVICE	500-165	BUILDINGS
101000	PLANT IN SERVICE	500-172	PIPELINES/GATHERING SYSTEM
101000	PLANT IN SERVICE	500-185	COMPRESSORS
101000	PLANT IN SERVICE	500-200	GAS PLANTS/FACILITIES
101000	PLANT IN SERVICE	501-050	PRELIMINARY ENGINEERING
101000	PLANT IN SERVICE	501-075	CONSTRUCTION ENGINEERING
101000	PLANT IN SERVICE	501-100	LEGAL, PERMITS, SURFACE DAMAGES, ROW
101000	PLANT IN SERVICE	501-110	ENVIRONMENTAL, ARCHEOLOGY, SURVEYS
101000	PLANT IN SERVICE	501-210	LOCATION, ROADS, TRENCHES, BORING
101000	PLANT IN SERVICE	501-220	SAND, GRAVEL, DIRT
101000	PLANT IN SERVICE	501-225	FENCING
101000	PLANT IN SERVICE	501-250	INSTALLATION COST
101000	PLANT IN SERVICE	501-260	TRANSPORTATION/GENERAL HAULING
101000	PLANT IN SERVICE	501-270	EQUIPMENT RENTALS
101000	PLANT IN SERVICE	501-370	ONSITE ENGINEERING/SUPERVISION
101000	PLANT IN SERVICE	501-460	HOUSING/COMMUNICATION
101000	PLANT IN SERVICE	501-475	TESTING
101000	PLANT IN SERVICE	501-500	PIPE - STEEL
101000	PLANT IN SERVICE	501-550	PIPE- POLY
101000	PLANT IN SERVICE	501-600	VALVES AND FITTINGS
101000	PLANT IN SERVICE	501-650	MEASUREMENT/ELECTRONIC EQUIPMENT
101000	PLANT IN SERVICE	501-690	MISC EQUIPMENT/SUPPLIES
101000	PLANT IN SERVICE	501-998	WIP PIPELINES CONTRA
101000	PLANT IN SERVICE	502-050	PRELIMINARY ENGINEERING
101000	PLANT IN SERVICE	502-075	CONSTRUCTION ENGINEERING
101000	PLANT IN SERVICE	502-100	LEGAL, PERMITS, SURFACE DAMAGES, ROW
101000	PLANT IN SERVICE	502-110	ENVIRONMENTAL, ARCHEOLOGY, SURVEYS
101000	PLANT IN SERVICE	502-210	LOCATION, ROADS, SITE WORK
101000	PLANT IN SERVICE	502-215	POND CONSTRUCTION
101000	PLANT IN SERVICE	502-220	SAND, GRAVEL, DIRT
101000	PLANT IN SERVICE	502-225	FENCING
101000	PLANT IN SERVICE	502-250	INSTALLATION COST
101000	PLANT IN SERVICE	502-260	TRANSPORTATION/GENERAL HAULING
101000	PLANT IN SERVICE	502-270	EQUIPMENT RENTALS
101000	PLANT IN SERVICE	502-370	ONSITE ENGINEERING/SUPERVISION
101000	PLANT IN SERVICE	502-460	HOUSING/COMMUNICATION

FERC Account	Description	Quorum Account	Quorum Acct Description
101000	PLANT IN SERVICE	502-475	TESTING
101000	PLANT IN SERVICE	502-500	FLOWLINES/PIPE
101000	PLANT IN SERVICE	502-600	VALVES/FITTINGS
101000	PLANT IN SERVICE	502-690	MISC EQUIPMENT/SUPPLIES
101000	PLANT IN SERVICE	502-700	COMPRESSORS
101000	PLANT IN SERVICE	502-710	AMINE SKID/PLANT
101000	PLANT IN SERVICE	502-720	BUILDINGS
101000	PLANT IN SERVICE	502-730	TANKS
101000	PLANT IN SERVICE	502-740	PUMPS/ PUMPSKIDS
101000	PLANT IN SERVICE	502-770	ELECTRICAL TRANSFORMERS
101000	PLANT IN SERVICE	502-780	ELECTRICAL CONTROLS
101000	PLANT IN SERVICE	502-998	WIP FACILITIES CONTRA
101304	PLANT IN SERVICE ARO	420-220	ARO ASSET
108000	ACCUM DEPR RESERVE	430-115	ACCUM DD&A - FASB 143
108000	ACCUM DEPR RESERVE	430-118	ACCUM DD&A - SALVAGE
108000	ACCUM DEPR RESERVE	510-100	ACCUM DEPR - OTHER PROPERTY
108000	ACCUM DEPR RESERVE	510-105	ACCUM DEPR - FIELD EQUIPMENT
108000	ACCUM DEPR RESERVE	510-135	ACCUM DEPR - TRANS EQUIP FIELD
108000	ACCUM DEPR RESERVE	510-137	ACCUM DEPR - TRANS EQUIP G&A
108000	ACCUM DEPR RESERVE	510-138	ACCUM DEPR - TRANSPORT BHMS
108000	ACCUM DEPR RESERVE	510-145	ACCUM DEPR - OFFICE FURN-FIELD
108000	ACCUM DEPR RESERVE	510-147	ACCUM DEPR - OFFICE FURN-G&A
108000	ACCUM DEPR RESERVE	510-155	ACCUM DEPR - COMPUTER - FIELD
108000	ACCUM DEPR RESERVE	510-157	ACCUM DEPR - COMPUTER - G&A
108000	ACCUM DEPR RESERVE	510-158	ACCUM DEPR - TRANS EQ BHMS
108000	ACCUM DEPR RESERVE	510-165	ACCUM DEPR - BUILDINGS
108000	ACCUM DEPR RESERVE	510-172	ACCUM DEPR - PIPELINES
108000	ACCUM DEPR RESERVE	510-185	ACCUM DEPR - COMPRESSORS
108000	ACCUM DEPR RESERVE	510-200	ACCUM DEPR - GAS PLANT/PIPELIN
118999	SVC CO UTILITY PLANT ALLOC	500-900	CORPORATE ASSETS ALLOCATED
119999	SVC CO ACCUM DEPR ALLOC	510-900	CORPORATE ACCUM DEPR ALLOCATED
122320	NON UTILITY-DEPLETION	430-110	ACCUM DD&A - OIL & GAS ASSETS
122320	NON UTILITY-DEPLETION	430-120	ACCUM DD&A - RETIREMENTS
122320	NON UTILITY-DEPLETION	430-130	ACCUM DD&A - UNECONOMICAL
131148	WELLS FARGO OPER CASH	100-110	BHEP WELLS MASTER ACCOUNT
131999	MONEY MARKET	100-120	BHEP WELLS A/P
134500	RESTRICTED CASH	100-410	RESTRICTED CASH ESCROW FUNDS
135000	WORKING FUNDS-	100-180	PETTY CASH
141000	NOTES RECEIVABLE	120-210	NOTES RECEIVABLE (NON I/C)
142200	CUSTR A/R MANUAL OFF SYS SALES	130-150	A/R - JOINT INTEREST BILLING
142200	CUSTR A/R MANUAL OFF SYS SALES	130-160	A/R - OUTSIDERS BILLING
142200	CUSTR A/R MANUAL OFF SYS SALES	130-400	A/R GAS BALANCING
143005	A/R ACCRUALS	110-110	CASH CLEARING
143005	A/R ACCRUALS	130-110	A/R - OIL & GAS SALES
143005	A/R ACCRUALS	130-115	A/R - OIL & GAS ESTIMATE

FERC Account	Description	Quorum Account	Quorum Acct Description
143038	A/R MEDICARE SUBSIDY	130-185	A/R - MEDICARE PART D SUBSIDY
143999	A/R OTHER TRADE RECEIVABLES	130-120	A/R - WGR JT INT GAS PLANT
143999	A/R OTHER TRADE RECEIVABLES	130-140	A/R - PROPERTY TAXES
143999	A/R OTHER TRADE RECEIVABLES	130-200	A/R - EMPLOYEES
143999	A/R OTHER TRADE RECEIVABLES	130-300	A/R - MISCELLANEOUS
143999	A/R OTHER TRADE RECEIVABLES	130-920	CUTBACK CLEARING
144000	ACCUM PROV FOR UNCOLL ACCTS	135-110	ALLOWANCE FOR DOUBTFUL ACCOUNT
146000	I/C ACCOUNTS RECEIVABLE	130-320	A/R - BH CORP
146000	I/C ACCOUNTS RECEIVABLE	130-325	A/R - BH SERVICE COMPANY, LLC
146000	I/C ACCOUNTS RECEIVABLE	130-335	A/R - BHUH
151005	FUEL STOCK-OIL	140-110	PROPANE
151005	FUEL STOCK-OIL	140-140	FIELD OIL
154003	INVENTORY MANUAL	140-310	MATERIALS INVENTORY
154100	INVENTORY - MISCELLANEOUS	140-320	MATERIALS MISCELLANEOUS
154105	INVENTORY - DIESEL	140-130	DIESEL
163000	STORES EXPENSE UNDISTRIBUTED-	140-315	INVENTORY CLEARING
165002	PREPAID INSURANCE	150-120	PREPAYMENTS - INSURANCE
165006	PREPAID PENSION	150-110	PREPAID PENSION
165007	PREPAID FEDERAL TAXES	150-150	PREPAID - FEDERAL INCOME TAX
165012	PREPAID OTHR	150-140	PREPAYMENTS - MISCELLANEOUS
165180	PREPAID STATE TAXES	150-160	PREPAID - STATE INCOME TAX
165182	PREPAID PROPERTY TAXES	150-125	PREPAID POSSESORY TAXES
165184	PREPAID PRODUCTION COSTS	150-135	PREPAYMENTS - CASH ADVANCES
171000	INTEREST & DIVIDENDS RECEIVABLE	160-210	INTEREST RECEIVABLE (NON I/C)
176000	DERIVATIVE MKT VALUE ASSET ST	170-120	DERIVATIVE CURRENT ASSETS
184999	OTHER CLEARING	130-170	A/R - CLEARING
186001	MISC DEFERRED DEBITS-IN PROCESS	520-145	LT RECEIVABLE/PREPAY
186030	DERIVATIVE MV ASSET - LT	520-160	DERIVATIVES-MRKT VALUE/ASSET
186998	DEFERRED ASSETS - OTHER	520-110	WGR OPERATING DEPOSIT
186998	DEFERRED ASSETS - OTHER	520-120	SURETY BONDS - CD'S
186998	DEFERRED ASSETS - OTHER	520-130	GOVT ROYALTIES
190175	DEFERRED TAX ASSET ST	170-130	DEF TAX - DERIV MV ASSET CURR
190175	DEFERRED TAX ASSET ST	170-132	DEF TAX ST DERIV MV ASSET CURR
190175	DEFERRED TAX ASSET ST	170-135	DEF TAX CUR - RESULTS COMP
190175	DEFERRED TAX ASSET ST	170-140	DEF TAX CUR-EE GROUP INSURANCE
190175	DEFERRED TAX ASSET ST	170-145	DTA ST-BAD DEBT RESERVE
190175	DEFERRED TAX ASSET ST	170-180	DEF TAX CUR-PRODUCTION TAXES
190520	DEFERRED TAX ASSET LT	170-150	DEF TAX - PENSION AOCI
190520	DEFERRED TAX ASSET LT	170-160	DEF TAX LT - PENSION - OCI
190520	DEFERRED TAX ASSET LT	170-165	DEF TAX-PENSION (ST) OCI
190520	DEFERRED TAX ASSET LT	170-170	DEF TAX LT-RETIREE HEALTH-OCI
190520	DEFERRED TAX ASSET LT	170-175	DEF TAX-RETIREE HC (ST) AOCI
190520	DEFERRED TAX ASSET LT	520-150	DTA LT - NON QUAL DEF COMP
190520	DEFERRED TAX ASSET LT	520-170	DEF TAX - DERIV MV ASSET LT
190520	DEFERRED TAX ASSET LT	520-172	DEF TAX ST DERIV MV ASSET LT

FERC Account	Description	Quorum Account	Quorum Acct Description
190520	DEFERRED TAX ASSET LT	520-175	DEF TAX FASB 143 CHNG IN ACCT
190520	DEFERRED TAX ASSET LT	520-180	NOL CARRYFORWARD
190520	DEFERRED TAX ASSET LT	520-185	RESERVE FOR NOL
190520	DEFERRED TAX ASSET LT	520-187	DEF TAX LT-STATE DEFERRED
190520	DEFERRED TAX ASSET LT	520-190	DEF TAX LT - DEPLETION
190520	DEFERRED TAX ASSET LT	520-195	DEF TAX LT - ASSET IMPARMENT
190520	DEFERRED TAX ASSET LT	520-200	DEF TAX LT - RETIREE HC
190520	DEFERRED TAX ASSET LT	520-205	DEF TAX LT - PERFORMANCE PLAN
190520	DEFERRED TAX ASSET LT	520-210	DEF TAX LT - PENSION
190520	DEFERRED TAX ASSET LT	520-215	DEF TAX LT % DEPLETION CF
190520	DEFERRED TAX ASSET LT	520-220	DEF TAX LT - STATE NOL
190520	DEFERRED TAX ASSET LT	520-230	DEF TAX LT - STATE NOL RESERVE
190520	DEFERRED TAX ASSET LT	520-240	DEF TAX - F E OF STATE FIN 48
190520	DEFERRED TAX ASSET LT	520-250	DEF TAX - FIN 48 ACCR INT
190520	DEFERRED TAX ASSET LT	520-260	DEF TAX LT - R&D CREDIT
199999	SUSPENSE BALANCING	670-798	CURRENT RETAINED EARNINGS
199999	SUSPENSE BALANCING	670-899	PRIOR YEAR'S RETAINED EARNINGS
201001	COMMON STOCK	660-110	COMMON STOCK
211001	ADDL PAID IN CAPITAL	660-120	CONTRIBUTED CAPITAL
216000	RETAINED EARNINGS GENERAL	670-140	NET INCOME YTD - 1986-2002
216020	CUM EFFECT ACCOUNTING ADJ	670-010	CUM EFFECT ACCT ADJ
216100	RETAINED EARNING SUBSIDIARIES-	670-305	RETAINED EARNINGS SUBSIDIARY
217000	TREASURY STOCK	660-130	TREASURY STOCK
219008	AOCI RETIREE HC	660-031	AOCI-RETIREE HC (GRS)-GL AMOR
219008	AOCI RETIREE HC	660-033	AOCI-RETIREE HC (GRS)-GL ANNUL
219008	AOCI RETIREE HC	660-093	AOCI-RETIREE HC DEFERRED (ST)
219009	AOCI DERIVATIVES SHORT TERM	660-100	AOCI - DERIVATIVES (GROSS)
219010	AOCI PENSION	660-021	AOCI-PENSION (GRS)-GL AMORT
219010	AOCI PENSION	660-023	AOCI-PENSION (GRS)-GL ANNUAL
219010	AOCI PENSION	660-092	AOCI-PENSION DEFERRED (ST)
219010	AOCI PENSION	660-140	AOCI - PENSION (GROSS)
219012	AOCI TRANSITION OBLIG RET HC	660-010	AOCI-TRANS OBL RETIREE HC(GRS)
219013	AOCI PENSION DEF TAX BENEFIT	660-025	AOCI-PENSION(FED TAX)
219013	AOCI PENSION DEF TAX BENEFIT	660-090	AOCI-PENSION (STATE TAX)
219015	AOCI TRANS OBLIG RET HC TAXBEN	660-015	AOCI-TRANS OBL RETIREE HC(FED)
219015	AOCI TRANS OBLIG RET HC TAXBEN	660-035	AOCI-RETIREE HC (FED TAX)
219015	AOCI TRANS OBLIG RET HC TAXBEN	660-070	AOCI-TRAN OBILG RETIREE HC(ST)
219015	AOCI TRANS OBLIG RET HC TAXBEN	660-075	AOCI-RETIREE HC (STATE TAX)
219016	AOCI DERIVATIVES TAX BENEFIT	660-105	AOCI - DERIVATIVES (TAX)
219016	AOCI DERIVATIVES TAX BENEFIT	660-107	AOCI - DERIVATIVES (ST TAX)
219018	AOCI DERIVATIVES LONG TERM	660-101	AOCI - LT DERIVATIVES (GROSS)
221000	LONG TERM DEBT	640-125	NOTES PAYABLE - OUTSIDERS L/T
228204	RESERVE MEDICAL	620-170	ACCRUED GROUP HEALTH & LIFE
232009	A/P MANUAL	600-110	A/P - VENDORS
232009	A/P MANUAL	600-240	UNAPPLIED ADVANCES

FERC Account	Description	Quorum Account	Quorum Acct Description
232016	A/P WH HEALTH INSURANCE	600-160	A/P - EMPLOYEE HEALTH CARE
232021	A/P WH EMPL DONATIONS	600-140	A/P - UNITED WAY
232024	A/P EMPLOYEE WH OTHER	600-150	A/P - EMPLOYEE CHILD CARE
232037	A/P GENERAL	600-120	A/P - MISCELLANEOUS
232037	A/P GENERAL	600-123	A/P - GAS IMBALANCE
232037	A/P GENERAL	600-125	A/P - LOE NON-OP CLEARING
233052	I/C NUMP NOTE PAY TO AFFILIATE	640-230	NOTES PAYABLE - BHC
233153	I/C INTEREST PAYABLE AFFILIATE	600-215	A/P - INT PAY - BHC
234000	I/C ACCOUNTS PAYABLE	600-280	A/P - BH CORP
234000	I/C ACCOUNTS PAYABLE	600-285	A/P - BH SERVICE COMPANY, LLC
236000	ACCRUED INCOME TAXES FEDERAL	600-190	A/P - FED INC TAXES - CURRENT
236000	ACCRUED INCOME TAXES FEDERAL	600-200	A/P - FED INC TAXES - PRIOR
236001	ACCRUED INCOME TAXES STATE	600-185	A/P - STATE INCOME TAXES
236004	ACCRUED PROPERTY TAXES	620-310	ACCRUED PRODUCTION TAXES EST
236004	ACCRUED PROPERTY TAXES	620-330	ACCRUED AD VALOREM - WESTON
236004	ACCRUED PROPERTY TAXES	620-436	ACCRUED AD VALOREM - NON OPER
236011	ACCRUED FUTA TAX	620-130	ACCRUED FUTA
236012	ACCRUED SUTA TAX	620-140	ACCRUED SUTA
236999	ACCRUED TAXES OTHER	620-580	ACCRUED SEV TAXES - COLORADO
236999	ACCRUED TAXES OTHER	620-585	ACCRUED PROD TAXES - NEW MEXCO
236999	ACCRUED TAXES OTHER	620-586	ACCRUED PROD TAXES - JICARILLA
236999	ACCRUED TAXES OTHER	620-587	ACCRUED JIC CAP IMPROVE TAX
236999	ACCRUED TAXES OTHER	620-588	ACCRUED INC TAX - NM
236999	ACCRUED TAXES OTHER	620-630	ACCRUED CONS TAXES - COLORADO
237999	ACCRUED INT OTHER	620-810	ACCRUED INTEREST (NON I/C)
239000	CURRENT MATURITIES OF LT DEBT	630-135	CURRENT PORTION - L/T OBLIGATI
241001	FEDERAL WITHHOLDING TAXES PAYB	620-120	ACCRUED FICA & FIT
241004	STATE SALES AND USE TAX	620-725	ACCRUED SALES TAX - NEW MEXICO
241004	STATE SALES AND USE TAX	620-730	ACCRUED SALES TAX - COLORADO
241004	STATE SALES AND USE TAX	620-735	ACCRUED SALES TAX - DENVER
241004	STATE SALES AND USE TAX	620-775	ACCRUED USE TAX - NM
241004	STATE SALES AND USE TAX	620-780	ACCRUED USE TAX - COLORADO
241004	STATE SALES AND USE TAX	620-785	ACCRUED USE TAX - DENVER
241006	STATE WITHHOLDING TAXES PAYABLE	620-125	ACCRUED COLO/NEW MEX STATE W/H
242001	ACCRUED AUDIT FEES	620-830	ACCRUED AUDIT FEES
242009	SFAS 106 CURRENT PORTIONS	620-175	ACCR LIAB - RETRIEE HC CURR
242013	ACCRUED BENEFITS 401K	600-170	A/P - EMPLOYEE 401K
242017	ACCRUED PARTNER DISTRIBUTIONS	610-100	R/P - LEASE LEVEL
242017	ACCRUED PARTNER DISTRIBUTIONS	610-110	R/P - JOINT INTEREST OWNERS
242017	ACCRUED PARTNER DISTRIBUTIONS	610-120	R/P - REVENUE PAYABLE ESTIMATE
242017	ACCRUED PARTNER DISTRIBUTIONS	610-130	R/P - ROYALTIES(FEDERAL)
242017	ACCRUED PARTNER DISTRIBUTIONS	610-140	R/P - ROYALTIES(STATE)
242017	ACCRUED PARTNER DISTRIBUTIONS	610-150	R/P - SUSPENSE-LEGAL
242017	ACCRUED PARTNER DISTRIBUTIONS	610-170	JIB/RP - SUSPENSE-MINIMUM
242017	ACCRUED PARTNER DISTRIBUTIONS	610-180	R/P - SUSPENSE-ESCHEAT

FERC Account	Description	Quorum Account	Quorum Acct Description
242017	ACCRUED PARTNER DISTRIBUTIONS	610-400	R/P - PIPELINE BALANCING
242024	ACCRUED ROYALTIES	620-880	ACCRUED ROYALTY/TAX OBLIGATION
242025	WELLS FARGO CD PAYROLL	620-110	ACCRUED PAYROLL
242041	ACCRUED INCENTIVE	620-190	ACCRUED RESULTS SHARING
242052	ACCRUED LT PERFORMANCE PLAN	620-210	ACCRUED PERFORMANCE PLAN & STK
242999	ACCRUED OTHER	600-127	A/P - UNPAID NON-OP
242999	ACCRUED OTHER	620-820	ACCRUED RESERVE STUDIES
242999	ACCRUED OTHER	620-850	RESERVE FOR NOL
242999	ACCRUED OTHER	620-890	ACCRUED LIABILITIES ESTIMATE
242999	ACCRUED OTHER	630-150	CURRENT ACQUISTION LIABILITIES
242999	ACCRUED OTHER	630-180	ACCRUED RELOCATION COSTS
244000	DERIVATIVE MV LIAB - ST	630-130	DERIVATIVE CURRENT LIABILITIES
253011	ACCRUED GROUP INS RETIREE LT	620-180	ACCRUED RETIREE HEALTH CARE LT
253100	ACCRUED PEP	620-160	ACCRUED PEP
253105	ACCRUED PENSION	620-150	ACCRUED PENSION COSTS
253120	NQDC SCHWAB	620-220	ACCRUED NDQC PLAN
253201	DERIV MV LIAB - LT	640-110	DERIVATIVES-MRKT VALUE/LIABLTY
253520	FIN48 LIABILITY	640-115	FIN 48 LIABILITY
254304	ARO LIABILITY – FASB 143	640-130	ASSET RETIRE OBLIG LIABILITY
282100	DEF TAX PROPERTY LT	650-110	DEF INC TAXES - GAS PLANT
282100	DEF TAX PROPERTY LT	650-120	DEF INC TAXES - OTHER PROPERTY
282100	DEF TAX PROPERTY LT	650-130	DEF INC TAXES - PROD PROPERTY
282100	DEF TAX PROPERTY LT	650-140	DEF INC TAXES - PROD PROP OTHE
282100	DEF TAX PROPERTY LT	650-200	DEF TAX-LT DRYHOLES
282100	DEF TAX PROPERTY LT	650-210	DEF TAX-LT UND LHC ABAND
282100	DEF TAX PROPERTY LT	650-220	DEF TAX-LT CAPITALIZED INT
283005	DEFERRED TAX LIAB ST	630-140	DEF TAX - DERIV MV LIAB CURR
283005	DEFERRED TAX LIAB ST	630-145	DEF TAX ST DERIV MV LIAB CURR
283005	DEFERRED TAX LIAB ST	630-147	DEF TAX CUR - PREPAID EXP
283005	DEFERRED TAX LIAB ST	630-149	DEF TAX CUR - DERIVATIVE
283005	DEFERRED TAX LIAB ST	630-170	DEF INCOME TAXES - STATE
283440	DEFERRED TAX LIAB LT	650-145	DEF INC TAXES - GAIN DEFERRAL
283440	DEFERRED TAX LIAB LT	650-150	DEF INC TAXES - OTHER
283440	DEFERRED TAX LIAB LT	650-160	DEF TAX - DERIV MV LIAB LT
283440	DEFERRED TAX LIAB LT	650-165	DEF TAX ST DERIV MV LIAB TX
283440	DEFERRED TAX LIAB LT	650-170	DEF INC TAXES - STATE
283440	DEFERRED TAX LIAB LT	650-180	DEF TAX FASB 143
283440	DEFERRED TAX LIAB LT	650-190	DEF TAX-PENSION (ST) AOCI
283440	DEFERRED TAX LIAB LT	650-192	DEF FED TAX-PENSION (LT)
283440	DEFERRED TAX LIAB LT	650-195	DEF TAX-RETIREE HC (ST) AOCI
283440	DEFERRED TAX LIAB LT	650-197	DEF FED TAX- RETIREE HC (LT)
283440	DEFERRED TAX LIAB LT	650-230	DEF TAX-LT PARTNERSHIPS
283440	DEFERRED TAX LIAB LT	650-240	DEF TAX LT - ROLLOVER ADJ
283440	DEFERRED TAX LIAB LT	650-250	DEF TAX LT - FED EFF ST NOL

BHUH
Article 5 of the Cost of Service Gas Agreement

Line No.				
1	Per Section 5.1(i) the Hedge Formula is as follows:			
2				
3	Hedge Credit = -(Net Income-((Allowed ROE + 100 basis points) * Invested Equity)) * 1/(1-T)			
4				
5	For illustrative Purposes Only the following is how this formula would work.			
6			3,250,000	Revenue from sales of Hydrocarbon
7				**COSGCO OpEx**
8			2,324,000	Operating Expenses
9			111,075	Interest Exp (40% of Investment Base)
10			814,925	Income Before Taxes
11			309,672	Ln 10 * 38% (Federal and State Taxes)
12	Net Income =		505,254	
13			1.61	Tax Gross up (1/(1-.38)
14	Hedge Credit		(166,366)	=-(ln12-((ln23+ln29)*ln27))*ln13
15				
16	Assumptions for the above calculation			
17	Equity %		60.00%	
18	Allowed Return on Equity (ROE)		9.86%	
19	Debt %		40.00%	
20	Allowed Cost of Debt		4.50%	
21	Return on Investment Base		7.72%	
22	Allowed Return % (monthly)	ln 21 ÷ 12	0.6433%	
23	Allowed ROE % (monthly)	ln 18 ÷ 12	0.8217%	
24	Allowed Cost of Debt % (monthly)	ln 20 ÷ 12	0.3750%	
25	Monthly Debt Expense	ln 26 * ln 19 * ln 24	111,075	
26	Investment Base	ln 25 Jul-Dec Forecast	74,050,000	
27	Invested Equity	ln 26 * ln 17	44,430,000	
28	100 Basis Points		1.00%	
29	100 Basis Points (monthly)	ln 28 ÷ 12	0.083%	
30				
31	All of the above information is from the Example Utility Hedge Forecast and the			
32	month of December 2016. Line 14 above is calculated in accordance with the Agreement			
33	and reconciles to Line 18 in the Example Utility Hedge Forecast that is developed in more			
34	of the traditional rate making process. There may be slight differences due to rounding			
35	but the overall calculations prove out the formula in the Agreement.			

BHUH
Article 5 of the Cost of Service Gas Agreement

Line No.				
1	Per Section 5.1(ii) the Hedge Formula is as follows:			
2				
3	Hedge Cost = -(Net Income-((Allowed ROE - 100 basis points) * Invested Equity)) * 1/(1-T)			
4				
5	For illustrative Purposes Only the following is how this formula would work.			
6			2,450,000	Revenue from sales of Hydrocarbon
7				**COSGCO OpEx**
8			2,054,000	Operating Expenses
9			86,075	Interest Exp (40% of Investment Base)
10			309,925	Income Before Taxes
11			117,772	Ln 10 * 38% (Federal and State Taxes)
12		Net Income =	192,154	
13			1.61	Tax Gross up (1/(1-.38)
14		Hedge Cost	100,107	=-(ln12-((ln23-ln29)*ln27))*ln13
15				
16	Assumptions for the above calculation			
17	Equity %		60.00%	
18	Allowed Return on Equity (ROE)		9.86%	
19	Debt %		40.00%	
20	Allowed Cost of Debt		4.50%	
21	Return on Investment Base		7.72%	
22	Allowed Return % (monthly)	ln 21 ÷ 12	0.6433%	
23	Allowed ROE % (monthly)	ln 18 ÷ 12	0.8217%	
24	Allowed Cost of Debt % (monthly)	ln 20 ÷ 12	0.3750%	
25	Monthly Debt Expense	ln 26 * ln 19 * ln 24	86,075	
26	Investment Base	ln 25 Jan-Jun Forecast	57,383,333	
27	Invested Equity	ln 26 * ln 17	34,430,000	
28	100 Basis Points		1.00%	
29	100 Basis Points (monthly)	ln 28 ÷ 12	0.083%	
30				
31	All of the above information is from the Example Utility Hedge Forecast and the			
32	month of April 2016. Line 14 above is calculated in accordance with the Agreement			
33	and reconciles to Line 18 in the Example Utility Hedge Forecast that is developed in more			
34	of the traditional rate making process. There may be slight differences due to rounding			
35	but the overall calculations prove out the formula in the Agreement.			

Exhibit CK-2 (sample calculation of hedge cost/(credit) and annual hedge reconciliation)

BHUH

Example Utility Hedge Forecast (Section 5.2 of the Agreement)

Line No.	FORECAST	Reference	Jan-16	Feb-16	Mar-16	Apr-16	May-16	Jun-16
1	**Production and Revenues: (All at COSGCO)**							
2	Natural Gas Sales ($4.00)		1,800,000	1,800,000	1,800,000	2,050,000	2,050,000	2,300,000
3	Liquids Sales (Oil & NGL)		350,000	350,000	350,000	400,000	400,000	450,000
4	Total Market Sales		2,150,000	2,150,000	2,150,000	2,450,000	2,450,000	2,750,000
5	**Expense Recovery (All at COSGCO)**							
6	Depr, Depl & Amort		850,000	850,000	850,000	925,000	925,000	1,000,000
7	Lease Operating Exp		50,000	50,000	50,000	55,000	55,000	60,000
8	Production Taxes		85,000	85,000	85,000	90,000	90,000	95,000
9	Gathering & Processing		830,000	830,000	830,000	830,000	830,000	830,000
10	Marketing/Scheduling Fees		45,000	45,000	45,000	50,000	50,000	55,000
11	General & Admin & Program Fees		104,000	104,000	104,000	104,000	104,000	104,000
12	**Total Expense Recovery**	sum (lns 6-11)	1,964,000	1,964,000	1,964,000	2,054,000	2,054,000	2,144,000
13	Income Taxes @ 38%	(ln 35/(1-.38))-ln 35	173,397	173,397	173,397	173,397	173,397	173,397
14	Monthly Return Amount	ln 34	369,147	369,147	369,147	369,147	369,147	369,147
15	**Total Revenue Requirement**	sum (lns 12-14)	2,506,544	2,506,544	2,506,544	2,596,544	2,596,544	2,686,544
16	**Over/(Under) Allowed ROE**	ln 4 - ln 15	(356,544)	(356,544)	(356,544)	(146,544)	(146,544)	63,456
17	**Risk Sharing deadband (+/-)**	ln 37	(46,277)	(46,277)	(46,277)	(46,277)	(46,277)	46,277
18	**Forecasted Hedge Cost/(Credit)**	**ln 17 - ln 16**	**310,267**	**310,267**	**310,267**	**100,267**	**100,267**	**(17,179)**
19	**Forecasted Investment Base:**							
20	Beginning Balance		50,000,000	49,000,000	48,000,000	58,000,000	56,900,000	66,800,000
21	Plus: New Gas Wells				11,000,000		11,000,000	
22	Less: Depr, Depl & Amort		(850,000)	(850,000)	(850,000)	(925,000)	(925,000)	(1,000,000)
23	+/- Deferred Taxes		(150,000)	(150,000)	(150,000)	(175,000)	(175,000)	(200,000)
24	Ending Balance	sum (lns 20-23)	49,000,000	48,000,000	58,000,000	56,900,000	66,800,000	65,600,000
25	Six Month Investment Base Average							57,383,333
26	**Return on Investment Base**							
27	Equity %		60.00%					
28	Allowed Return on Equity (ROE)		9.86%					
29	Debt %		40.00%					
30	Interest Rate		4.50%					
31	Return on Investment Base		7.72%					
32	Monthly Return %	ln 31 ÷ 12	0.6433%					
33	Monthly ROE %	ln 28 ÷ 12	0.8217%					
34	Monthly Authorized Return	ln 25 * ln 32	369,147	369,147	369,147	369,147	369,147	369,147
35	Monthly Equity Amount	ln 25 * ln 27 * ln 33	282,911	282,911	282,911	282,911	282,911	282,911
36	Monthly Risk Sharing Amount	ln 25 * ln 27 * (1% ÷ 12)	28,692	28,692	28,692	28,692	28,692	28,692
37	Total Risk Sharing including Tax	ln 36 * (1/(1-.38))	46,277	46,277	46,277	46,277	46,277	46,277

BHUH

Example Utility Hedge Forecast (Section 5.2 of the Agreement)

Line No.	FORECAST	Reference	Jul-16	Aug-16	Sep-16	Oct-16	Nov-16	Dec-16
1	**Production and Revenues: (All at COSGCO)**							
2	Natural Gas Sales ($4.00)		2,300,000	2,300,000	2,550,000	2,550,000	2,550,000	2,800,000
3	Liquids Sales (Oil & NGL)		450,000	450,000	450,000	450,000	450,000	450,000
4	Total Market Sales		2,750,000	2,750,000	3,000,000	3,000,000	3,000,000	3,250,000
5	**Expense Recovery (All at COSGCO)**							
6	Depr, Depl & Amort		1,000,000	1,000,000	1,075,000	1,075,000	1,075,000	1,150,000
7	Lease Operating Exp		60,000	60,000	65,000	65,000	65,000	70,000
8	Production Taxes		95,000	95,000	100,000	100,000	100,000	105,000
9	Gathering & Processing		830,000	830,000	830,000	830,000	830,000	830,000
10	Marketing/Scheduling Fees		55,000	55,000	60,000	60,000	60,000	65,000
11	General & Admin & Program Fees		104,000	104,000	104,000	104,000	104,000	104,000
12	**Total Expense Recovery**	sum (lns 6-11)	2,144,000	2,144,000	2,234,000	2,234,000	2,234,000	2,324,000
13	Income Taxes @ 38%	(ln 35/(1-.38))-ln 35	223,760	223,760	223,760	223,760	223,760	223,760
14	Monthly Return Amount	ln 34	476,364	476,364	476,364	476,364	476,364	476,364
15	**Total Revenue Requirement**	sum (lns 12-14)	2,844,123	2,844,123	2,934,123	2,934,123	2,934,123	3,024,123
16	**Over/(Under) Allowed ROE**	ln 4 - ln 15	(94,123)	(94,123)	65,877	65,877	65,877	225,877
17	**Risk Sharing deadband (+/-)**	ln 37	(59,718)	(59,718)	59,718	59,718	59,718	59,718
18	**Forecasted Hedge Cost/(Credit)**	**ln 17 - ln 16**	**34,405**	**34,405**	**(6,159)**	**(6,159)**	**(6,159)**	**(166,159)**
19	**Forecasted Investment Base:**							
20	Beginning Balance		65,600,000	64,400,000	74,200,000	72,900,000	71,600,000	81,300,000
21	Plus: New Gas Wells			11,000,000			11,000,000	
22	Less: Depr, Depl & Amort		(1,000,000)	(1,000,000)	(1,075,000)	(1,075,000)	(1,075,000)	(1,150,000)
23	+/- Deferred Taxes		(200,000)	(200,000)	(225,000)	(225,000)	(225,000)	(250,000)
24	Ending Balance	sum (lns 20-23)	64,400,000	74,200,000	72,900,000	71,600,000	81,300,000	79,900,000
25	Six Month Investment Base Average							74,050,000
26	**Return on Investment Base**							
27	Equity %		60.00%					
28	Allowed Return on Equity (ROE)		9.86%					
29	Debt %		40.00%					
30	Interest Rate		4.50%					
31	Return on Investment Base		7.72%					
32	Monthly Return %	ln 31 ÷ 12	0.6433%					
33	Monthly ROE %	ln 28 ÷ 12	0.8217%					
34	Monthly Authorized Return	ln 25 * ln 32	476,364	476,364	476,364	476,364	476,364	476,364
35	Monthly Equity Amount	ln 25 * ln 27 * ln 33	365,081	365,081	365,081	365,081	365,081	365,081
36	Monthly Risk Sharing Amount	ln 25 * ln 27 * (1% ÷ 12)	37,025	37,025	37,025	37,025	37,025	37,025
37	Total Risk Sharing including Tax	ln 36 * (1/(1-.38))	59,718	59,718	59,718	59,718	59,718	59,718

Exhibit CK-2 (sample calculation of hedge cost/(credit) and annual hedge reconciliation)

BHUH

Hedge Year-End Calculation (Section 5.3 of the Agreement)

Line No.	Actual Performance	Reference	Jan-16	Feb-16	Mar-16	Apr-16	May-16	Jun-16	Jul-16
1	**Production and Revenues: (All at COSGCO)**								
2	Natural Gas Sales ($4.15)		1,867,500	1,867,500	1,867,500	2,117,500	2,117,500	2,367,500	2,367,500
3	Liquids Sales (Oil & NGL)		300,000	300,000	300,000	350,000	350,000	400,000	400,000
4	Total Market Sales		2,167,500	2,167,500	2,167,500	2,467,500	2,467,500	2,767,500	2,767,500
5	**Expense Recovery (All at COSGCO)**								
6	Depr, Depl & Amort		851,235	851,235	851,235	926,235	926,235	1,001,235	1,001,235
7	Lease Operating Exp		52,358	52,358	52,358	57,358	57,358	62,358	62,358
8	Production Taxes		86,851	86,851	86,851	91,851	91,851	96,851	96,851
9	Gathering & Processing		865,651	865,651	865,651	865,651	865,651	865,651	865,651
10	Marketing/Scheduling Fees		45,365	45,365	45,365	50,365	50,365	55,365	55,365
11	General & Admin & Program Fees		106,891	106,891	106,891	106,891	106,891	106,891	106,891
12	**Total Expense Recovery**	sum (lns 6-11)	2,008,351	2,008,351	2,008,351	2,098,351	2,098,351	2,188,351	2,188,351
13	Income Taxes @ 38%	(ln 30/(1-.38))-ln 30							
14	Return Amount	ln 33							
15	**Total Revenue Requirement**	sum (lns 12-14)	2,008,351	2,008,351	2,008,351	2,098,351	2,098,351	2,188,351	2,188,351
16	**Over/(Under) Allowed ROE**	**ln 4 - ln 15**							
17	**Risk Sharing Deadband (+/-)**	**ln 35**							
18	**Actual Hedge Cost/(Credit)**	**ln 17 - ln 16**							
19	**Forecasted Hedge Cost/(Credit) Calendar Year**								
20	**Customer (Refund)/Collection**	**ln 18 - ln 19**							
21	**Investment Base:**								
22	Beginning Balance		50,000,000	48,983,530	47,967,060	57,626,540	56,510,070	66,744,465	65,527,995
23	Plus: New Gas Wells				10,675,950		11,350,865		
24	Less: Depr, Depl & Amort		(851,235)	(851,235)	(851,235)	(926,235)	(926,235)	(1,001,235)	(1,001,235)
25	+/- Deferred Taxes		(165,235)	(165,235)	(165,235)	(190,235)	(190,235)	(215,235)	(215,235)
26	Ending Balance	sum (lns 22-25)	48,983,530	47,967,060	57,626,540	56,510,070	66,744,465	65,527,995	64,311,525
27	13 Month Average for Investment Base								
28	**Return on Investment Base**								
29	Equity %		60.00%						
30	Allowed Return on Equity (ROE)		9.95%						
31	Debt %		40.00%						
32	Interest Rate		4.50%						
33	Return on Investment Base		7.77%						
34	100 Basis Point Risk Sharing		1.00%						
35	Total Risk Sharing Amount including taxes								

Exhibit CK-2 (sample calculation of hedge cost/(credit) and annual hedge reconciliation)

BHUH

Hedge Year-End Calculation (Section 5.3 of the Agreement)

Line No.	**Actual Performance**	Reference	Aug-16	Sep-16	Oct-16	Nov-16	Dec-16	Calendar Yr Actual
1	**Production and Revenues: (All at COSGCO)**							
2	Natural Gas Sales ($4.15)		2,367,500	2,617,500	2,617,500	2,617,500	2,867,500	27,660,000
3	Liquids Sales (Oil & NGL)		400,000	400,000	400,000	400,000	400,000	4,400,000
4	Total Market Sales		2,767,500	3,017,500	3,017,500	3,017,500	3,267,500	32,060,000
5	**Expense Recovery (All at COSGCO)**							
6	Depr, Depl & Amort		1,001,235	1,076,235	1,076,235	1,076,235	1,151,235	11,789,820
7	Lease Operating Exp		62,358	67,358	67,358	67,358	72,358	733,296
8	Production Taxes		96,851	101,851	101,851	101,851	106,851	1,147,212
9	Gathering & Processing		865,651	865,651	865,651	865,651	865,651	10,387,812
10	Marketing/Scheduling Fees		55,365	60,365	60,365	60,365	65,365	649,380
11	General & Admin & Program Fees		106,891	106,891	106,891	106,891	106,891	1,282,692
12	**Total Expense Recovery**	sum (lns 6-11)	2,188,351	2,278,351	2,278,351	2,278,351	2,368,351	25,990,212
13	Income Taxes @ 38%	(ln 30/(1-.38))-ln 30						2,343,211
14	Return Amount	ln 33						4,975,837
15	**Total Revenue Requirement**	sum (lns 12-14)	2,188,351	2,278,351	2,278,351	2,278,351	2,368,351	33,309,260
16	**Over/(Under) Allowed ROE**	**ln 4 - ln 15**						**(1,249,260)**
17	**Risk Sharing Deadband (+/-)**	**ln 35**						**(619,733)**
18	**Actual Hedge Cost/(Credit)**	**ln 17 - ln 16**					**Amount outside of the Deadband**	**629,527**
19	**Forecasted Hedge Cost/(Credit) Calendar Year**							**998,332**
20	**Customer (Refund)/Collection**	**ln 18 - ln 19**						**(368,806)**
21	**Investment Base:**							
22	Beginning Balance		64,311,525	73,660,905	72,344,435	71,027,965	79,610,045	
23	Plus: New Gas Wells		10,565,850			9,898,550		
24	Less: Depr, Depl & Amort		(1,001,235)	(1,076,235)	(1,076,235)	(1,076,235)	(1,151,235)	
25	+/- Deferred Taxes		(215,235)	(240,235)	(240,235)	(240,235)	(265,235)	
26	Ending Balance	sum (lns 22-25)	73,660,905	72,344,435	71,027,965	79,610,045	78,193,575	
27	13 Month Average for Investment Base							64,039,085
28	**Return on Investment Base**							
29	Equity %							
30	Allowed Return on Equity (ROE)						ln 27 * ln 29 * ln 30	3,823,133
31	Debt %							
32	Interest Rate							
33	Return on Investment Base						ln 27 * ln 33	4,975,837
34	100 Basis Point Risk Sharing						ln 27 * ln 29 * ln 34	384,235
35	Total Risk Sharing Amount including taxes						ln 34 * (1/(1-.38))	619,733

BHUH
Hedge Cost/(Credit) Allocation to Each State

Line No.	State:	Current Annual Demand	Hedge Target	Percentage Share
1	Iowa	17,300,000	8,650,000	23.83%
2	Kansas	13,000,000	6,500,000	17.91%
3	Nebraska	16,200,000	8,100,000	22.31%
4	Colorado	19,000,000	9,500,000	26.17%
5	Wyoming	6,500,000	3,250,000	8.95%
6	South Dakota	600,000	300,000	0.83%
7		72,600,000	36,300,000	

Line No.		Jan-16	Feb-16	Mar-16	Apr-16	May-16	Jun-16
8		Jan-16	Feb-16	Mar-16	Apr-16	May-16	Jun-16
9	Hedge Forecast Amount - Total	310,267	310,267	310,267	100,267	100,267	(17,179)
10	**Each State's Percentage Share to be Included in the Monthly Adjustment Clause Calculation**						
11	Iowa	73,934	73,934	73,934	23,893	23,893	(4,094)
12	Kansas	55,558	55,558	55,558	17,954	17,954	(3,076)
13	Nebraska	69,233	69,233	69,233	22,374	22,374	(3,833)
14	Colorado	81,199	81,199	81,199	26,241	26,241	(4,496)
15	Wyoming	27,779	27,779	27,779	8,977	8,977	(1,538)
16	South Dakota	2,564	2,564	2,564	829	829	(142)
17		310,267	310,267	310,267	100,267	100,267	(17,179)
18							

Line No.		Jul-16	Aug-16	Sep-16	Oct-16	Nov-16	Dec-16
19		Jul-16	Aug-16	Sep-16	Oct-16	Nov-16	Dec-16
20	Hedge Forecast Amount - Total	34,405	34,405	(6,159)	(6,159)	(6,159)	(166,159)
21	**Each State's Percentage Share to be Included in the Monthly Adjustment Clause Calculation**						
22	Iowa	8,199	8,199	(1,468)	(1,468)	(1,468)	(39,594)
23	Kansas	6,161	6,161	(1,103)	(1,103)	(1,103)	(29,753)
24	Nebraska	7,677	7,677	(1,374)	(1,374)	(1,374)	(37,077)
25	Colorado	9,004	9,004	(1,612)	(1,612)	(1,612)	(43,485)
26	Wyoming	3,080	3,080	(551)	(551)	(551)	(14,877)
27	South Dakota	284	284	(51)	(51)	(51)	(1,373)
28		34,405	34,405	(6,159)	(6,159)	(6,159)	(166,159)
29							

Line No.			
30	**Hedge Year-End Calculation - Customer (Refund)/Collection**		(368,806)
31	Iowa	(87,883)	
32	Kansas	(66,040)	
33	Nebraska	(82,295)	
34	Colorado	(96,519)	
35	Wyoming	(33,020)	
36	South Dakota	(3,048)	

The Hedge Year-End amounts will be included in the 6 month forecast for customer rates going into effect in July.

SUPERSEDED INDEX

NEW **REPLACES**

Index	**Section**	**Sheet**	**Description/Title**	Index	**Revision**	**Sheet**	**Effective Date**
2	Index	1 of 2	Superseded Index 5th Revised	2	Fourth Revised	1 of 2	March 1, 2010
3	Index	1 of 1	General Information Communities Served	3	Original	1 of 2	September 1, 2010
13	Index	1 of 2	Rate Schedule Index Fourth Revised	13	Fourth Revised	1 of 2	March 1, 2010
15	Index	1 of 2	Rate Schedule Energy Options Program	15	Third Revised	1 of 2	March 1, 2010
16	Index	1 of 2	Rate Schedule Economic Development Rate	16	Third Revised	1 of 2	March 1, 2010
21	Index	1 of 3	General Service Terms and Conditions	21	Original	1 of 3	March 1, 2010
23	Index	1 of 2	Billing and Payments	23	Third Revised	1 of 2	March 1, 2010
23	Index	2 of 2	Billing and Payments	23	Second Revised	2 of 2	March 1, 2010
26	Index	1 of 3	Emergency Curtailment Plan	26	Second Revised	1 of 3	March 1, 2010
1	Index	1 of 2	General Index Third revised	2	Second Revised	1 of 2	November 1, 2007
2	Index	1 of 2	Superseded Index Sixth Revised	2	~~Fifth Revised~~ Seventh Revised	1 of 2	~~March 1, 2010~~ August 6, 2015
17	RS	1 of 1	Rate Schedule Pipeline Replacement Charge First Revised	17	Original	1 of 1	June 1, 2005
17	RS	1 of 1	Rate Schedule Pipeline Replacement Charge Second Revised	**17**	First Revised	1 of 1	December 1, 2013
8	GCA	1 of 4	Purchased Gas Cost Adjustment (PGA)	8	Third Revised	1 of 4	November 1, 2009
8	GCA	2 of 4	Purchased Gas Cost Adjustment (PGA)	8	Third Revised	2 of 4	November 1, 2009

PURCHASED GAS COST ADJUSTMENT (PGA)

I. TRADITONAL SALES SERVICE

1. Purchased Cost of Gas:
For purposes of calculating the monthly gas purchase price per therm (PGA), costs shall include, but not limited to, upstream pipeline capacity, interstate pipeline transition charges, interstate pipeline or supplier refunds, wholesale commodity cost including the Cost of Service Gas Program as set forth in the Cost of Service Gas Agreement, pipeline commodity transportation fuel.

The monthly PGA factor per therm shall be shown on the bill as a separate line item.

2. Computation:
In addition to the base rates in effect for residential and commercial service, a charge per therm shall be added for the monthly average cost of purchased gas. The monthly charge per therm shall be calculated as follows:

$$PGA = \frac{G - R}{S}$$

Where:

PGA = Monthly estimated purchased gas cost factor per therm.

G = The annualized estimated delivered costs, including L&U, for natural gas purchased for resale, based on prices in effect for the current month.

R = The annualized amount of any refunds received from any gas suppliers or interstate pipeline.

S = Estimated annual firm sales volumes (therms).

3. Annual Gas Cost Reconciliation:
Annually, on or before October 1st, Black Hills Energy shall compute a "Gas Cost Reconciliation Factor" (GCR) for each Rate Area. The computation will compare the actual cost of gas purchased (including propane) with actual billed revenue arising from the components of retail rates, which are attributable to the cost of gas purchased. Each such comparison shall be for the year ended the immediately preceding June 30. The computation will specify a reconciliation rate adjustment to become effective November 1. This GCR adjustment will correct for any difference between gas cost incurred on behalf of the traditional sales customer and gas cost recovered for the reconciliation year ended June 30, and will correct for the previous year's reconciliation adjustment.

~~Vice President~~Manager, Regulatory Affairs

PURCHASED GAS COST ADJUSTMENT (PGA)
(Continued)

$$GCR = \frac{P - BR + D - \mathbf{CB}}{S}$$

Where:

P = Actual annual cost of all gas cost components described in Paragraph I (1) .

BR = Annual billed revenue for the reconciling period described in Paragraph I (3).

S = Estimated annual sales volumes (therms) for the PGA customers.

D = Annual bad debt component as allowed in Docket No. NG-004.1.

CB = Annual Retail Service Credit (see III. Below)

The GCR factor per therm shall be shown as a separate line item on the customer's monthly bill.

II. ANNUAL PRICE SALES SERVICE (optional)

1. Annual Price Option Cost of Gas:

The rate per therm for the Annual Price Option cost of gas shall remain constant during the twelve month period beginning November 1 and ending October 31 of the following year. The Annual Price Option (APO) shall be calculated on a per therm basis and shall include, but not limited to, upstream pipeline capacity, interstate pipeline transition charges, PNG Pipeline (Rate Area II only), interstate pipeline and supplier refunds, estimated wholesale commodity cost including the Cost of Service Gas Program as set forth in the Cost of Service Gas Agreement,, pipeline commodity transportation, and fuel.

The APO shall be shown on the customer's bill as a separate line item labeled "PGA".

2. Computation:

In addition to the base rates in effect for residential and commercial service, a charge per therm shall be added for the monthly usage of natural gas. The APO charge per therm shall be calculated as follows:

$$APO = \frac{G - R}{S}$$ (Shown as "PGA" on customer's bill)

~~Vice President~~Manager, Regulatory Affairs