PUBLIC VIEW

Direct Testimony
Julia M. Ryan

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I. INTRODUCTION AND QUALIFICATIONS

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Julia M. Ryan. My business address is 716 Boylston Ave. E, Suite 10, Seattle WA 98102.

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

A. I am Managing Partner for Aether Advisors LLC, a management consulting firm. Black Hills Utility Holdings Inc. ("BHUH") retained my services in connection with assessing its hedging program and providing decisional criteria for long-term hedging. BHUH is a wholly owned subsidiary of Black Hills Corporation ("BHC").

Q. FOR WHOM ARE YOU TESTIFYING?

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

Q. PLEASE DESCRIBE YOUR EDUCATIONAL AND BUSINESS BACKGROUND.

A. I received a Bachelor's degree from Smith College, Northampton MA and was recruited to be a commodity trader for Louis Dreyfus Corporation upon graduation in 1984. I held several merchant positions at the firm and in 1989 I led the natural gas trading and marketing desk where I was promoted to Vice President. Not long after the natural gas trading operations were integrated with the power trading operations in the newly formed Duke/Louis Dreyfus joint venture, I transferred into the Strategic Initiatives group as a Senior Vice President, responsible for retail marketing activities and a joint marketing agreement with a local gas distribution company. In 1996, I left Louis Dreyfus to start a new energy and marketing firm as one of four principals. Merchant Energy of the Americas (MEGA) was owned by Gener S.A., and was later acquired by TransAlta Corp. I helped set up the trading and risk management functions and then co-led national marketing initiatives as Managing Director- Origination. In 2001, I left MEGA to assume responsibility for Puget Sound Energy's natural gas and electric utilities' supply operations as Vice President Energy Portfolio Management, where I supervised the utilities' energy supply management function, oversaw the hedging program, and acted as a company witness in a number of regulatory filings. In 2005, I became the Vice President of Risk Management and Strategic Planning, leading risk operations composed of Risk Control, Credit Risk, Internal Audit, and Corporate Budgeting. In 2006, I became a consultant and established Aether Advisors LLC in 2008. Since 2006, I have advised utility clients in the areas of risk management and strategy. It is in this capacity that I provided advisory services to BHUH. I am also the Program Director for the Willamette University Atkinson Graduate School of Management's "Utility Management Certificate Program," and I am the Chair of the Seattle City Light Review Panel.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THIS COMMISSION?

A. No. I have previously testified on multiple occasions before the Washington Utilities and Transportation Commission.

II. PURPOSE OF TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY?

A. The purpose of my testimony is to describe the work Aether Advisors LLC ("Aether") completed for BHUH in connection with the Cost of Service Gas Program (the "COSG Program"). BHUH, which procures gas supply or assists in procuring that supply for the Company and other BHC utilities, engaged Aether to review the current hedging program, to assess whether it should incorporate long-term hedging into its current program, and to provide recommendations related to the proposed COSG Program. Aether conducted a qualitative market analysis and a quantitative portfolio analysis to develop recommendations on how the portfolio should be hedged. Aether explained why BHUH should consider long-term hedging, recommended a target range for long-term hedging (percent of forecasted gas supply needs), and proposed how long-term hedging could be integrated with short-term and medium-term hedging. Aether delivered its report, titled "Gas Supply Portfolio Design", which is attached to my testimony as Exhibit JMR-1 ("Report").

Q. HOW IS THE REPORT ORGANIZED AND WHAT TOPICS DOES IT COVER?

A. In Part 1 – Current Gas Supply Portfolio Review of the Report, Aether summarized BHUH's current and prospective gas supply procurement activities, from the perspective of managing price exposure for gas and electric utility customers. In Part 2 – Gas Supply Hedging Options, Aether explained how a utility's hedging program is influenced by its hedging objectives and described tools generally available to utilities to hedge natural gas price risk exposure in short-term, medium-term, and long-term markets.[1] In Part 3 – Long-Term Factors and Opportunity Assessment, Aether provided decisional criteria for long-term hedging. And in Part 4 – Portfolio Modeling, Aether modeled BHUH's aggregated gas supply portfolio, showing the effect of different hedging scenarios combined with different market price scenarios on its long-term gas supply costs. Lastly, in Part 5 – Conclusions and Recommendations, Aether recommended that BHUH acquire long-term gas production. Additionally, Aether proposed an integrated short-term, medium-term and long-term gas hedging approach.

[1] Short-term hedging refers to hedging for the current Gas Supply Year and the upcoming Gas Supply Year (Gas Supply Years 1-2); medium-term hedging refers to hedging for Gas Supply Years 3-7; and long-term hedging refers to the time horizon beyond Gas Supply Year 7.

III. <u>CURRENT GAS SUPPLY PORTFOLIO REVIEW</u>

Q. WHAT TYPE OF COMMODITY PRICE RISK EXPOSURE DO GAS UTILITY CUSTOMERS HAVE?

A. Gas customers use natural gas for heating, cooling, cooking, water heating, and manufacturing processes. A natural gas utility has the obligation to serve gas customers with either gas supply service or gas transportation service. Typically only the largest customers procure their own gas supply and take transportation service. Most gas customers (chiefly residential and commercial customers) rely upon the utility to purchase gas supply to meet their needs. The cost of the gas supply is passed through at a tariff rate reflecting the utility's cost to acquire the gas. A utility's purchasing practices and the direction of the wholesale natural gas market prices affect the customers' cost of gas supply. If a utility purchases natural gas in the spot market (representing one day to one month forward in time), customers will bear the cost of whatever the spot wholesale market price is at that particular time. If the gas utility can stabilize gas supply costs, there is less rate uncertainty for customers. In this way, customers benefit by being protected against rising natural gas prices.

Q. WHAT TYPE OF COMMODITY PRICE RISK EXPOSURE DO ELECTRIC UTILITY CUSTOMERS HAVE?

A. Electric customers do not use natural gas directly, but natural gas is a fuel for natural gas-fired power plants. Similar to the way a gas utility manages gas supply costs for its natural gas utility customers, an electric utility manages gas fuel costs for its electric customers. Customers benefit from stabilized fuel supply costs and the natural gas fuel hedge mitigates the risk of rising natural gas prices.

Q. WHAT IS 'HEDGING' AND WHAT PURPOSE DOES IT SERVE?

A. In the Report, I explained that "hedging" refers to strategies to manage the cost of natural gas, providing rate stability and reducing the risk of rising natural gas costs for the utility's customers. When a utility can fix or cap the price in a forward contract, it is hedging. This is a deliberate action to manage costs and is not speculative. Instead, utilities' hedging is the act of reducing price risk exposure in a portfolio and is not related to profit and gain or trying to "beat the market". The act of locking into a price means the utility has accepted that price on behalf of its customers. It is willing to forego further opportunity in exchange for protecting against prices moving disadvantageously for customers.

Q. HOW DID AETHER CONDUCT ITS ASSESSMENT OF THE CURRENT HEDGING PROGRAM?

A. As explained in Ivan Vancas' direct testimony, BHUH is involved in procuring gas for the Company and other BHC utilities. As such, I met BHUH representatives and reviewed internal documents related to its hedging program. The focus of this meeting and review was on BHUH's gas procurement. I looked at the hedging time horizon to review how far forward BHUH hedges and examined the percentage of gas supply hedged by year to understand the size and scale of the hedging program. I also reviewed the hedging protocols to understand how BHUH executed its hedges. And, I reviewed the instruments used to mitigate price risk.

Q. **WHAT CONNECTION DID YOU FIND BETWEEN THE OVERALL GAS SUPPLY GOALS AND THE HEDGING PROGRAM?**

A. BHUH's gas supply goals are to 1) provide reasonably priced natural gas; 2) provide a high level of reliability; and 3) mitigate price volatility through its hedging program. I found its hedging program to be consistent with its gas supply goals. Further, the hedging instruments are consistent with the hedging goals.

Q. WHAT WERE YOUR CONCLUSIONS AFTER REVIEWING THE HEDGING PROGRAM?

A. I found BHUH's hedging to be well-structured and very transparent. Additionally, the hedging program goals are clearly articulated and the hedging protocols are well understood. BHUH uses a portfolio of hedging instruments that are appropriate for utility hedging: natural gas storage, fixed price, and call options. BHUH manages market price risk, load variability, and credit risk consistent with utility industry practices. Success is measured through effective execution of the hedging program, providing price protection at a reasonable cost, and the ability to protect customers from price volatility.

Q. DID YOU FIND DIFFERENCES BETWEEN BHUH'S HEDGING PROGRAMS FOR THE DIFFERENT BHC UTILITIES?

A. The design and tenor of BHUH's hedging for the BHC's natural gas utilities' is similar, focusing on managing price exposure one to two winters forward in time. There are minor variations from state to state, with different weightings of instruments, but the focus on winter-seasonal price volatility is consistent. BHUH uses natural gas storage, fixed price contracts, and call options to hedge for gas utilities. The one utility that hedges beyond the short-term is the Colorado electric utility, hedging five years forward in time using fixed price physical contracts. Figure 11 – Hedging Plan Summary by State in the Report shows the detailed percentage of hedges and time horizon for each utility. In addition, Exhibit IV2 of Ivan Vancas' direct testimony contains a summary of each Black Hills' utility's respective hedging percentages and mix.

Q. PLEASE EXPLAIN THE RECOMMENDATION YOU MADE CONCERNING THE EXISTING HEDGING PROGRAM?

A. I recommended that BHUH extend the time horizon of the hedging program and increase the percentage hedged. The current mix of instruments has been effective for protecting against seasonal price spikes in the short-term. However, if the objective is to offer more rate stability over an extended time horizon, then the gas utilities' short-term seasonal hedging program will not be adequate. If BHUH entered into longer-term hedging, the commodity cost of gas would be smoother over time, offering more rate stability for customers. This is because a hedging program over multiple years narrows the range within which gas supply costs can change from one rate year to another. This is demonstrated in more detail in Figure 7 below and the related testimony. I proposed that BHUH's hedging plan link together short-term, medium-term, and long-term hedging. And in this context, I recommended BHUH set a hedging band for the short-term and medium-term horizon with minimum and maximum levels. BHUH would hedge between the minimum and maximum levels based upon forward fundamental and technical market analysis.

Q. IS THE COSG PROGRAM CONSISTENT WITH YOUR RECOMMENDATION?

A. Yes. The strategy to invest in natural gas reserves to serve regulated customers is consistent with Aether's recommendation that BHUH hedge further forward in time. The COSG Program offers greater rate stability over the long term. Specifically, if COSGCO (the entity that would own the reserves under the proposed COSG Program) acquired gas reserves, the Company's customers would have less exposure to medium-term and long-term price volatility and price appreciation, because the gas production revenues under the COSG Program would hedge price exposure associated with the utility's gas purchases.

Q. HAVE OTHER UTILITIES ENGAGED IN LONG-TERM HEDGING BY ACQUIRING RESERVES?

A. Yes, quite a few have. The COSG Program is consistent with other utilities' strategies to acquire long-term price protection for customers through the acquisition of reserves. Appendix A- Illustrative Utility Hedging Through the Acquisition of Reserves in the Report includes examples of long-term utility hedging programs using gas reserves.

IV. GAS SUPPLY HEDGING OPTIONS

Q. WHAT TOOLS ARE AVAILABLE TO MANAGE NATURAL GAS PRICE VOLATILITY FOR CUSTOMERS?

A. There are several tools for medium-term and long-term gas supply portfolio management, some of which are also used for BHUH's short-term hedging. The Report describes how and when different instruments could be used to achieve certain hedging strategies. With respect to medium-term hedging, I focused on the use of physical and financial hedging instruments. For long-term hedging, I reviewed the use of long-term contracts, volumetric production payments, and investment in reserves to reduce supply cost volatility and to stabilize gas supply costs for customers.

Q. HOW WOULD YOU COMPARE HEDGING WITH LONG-TERM CONTRACTS TO OWNING RESERVES?

A. There may be limited market liquidity to transact a long-term fixed price supply contract. In addition there are counterparty and credit risks associated with a long-term fixed price supply contract (please see Part 2 – Gas Supply Hedging Options, section C. Credit Consideration: Counterparty Risk and Collateral Posting, in the Report for additional detail). In contrast, with owning gas reserves, the utility or an affiliate holds title to the asset and can control when additional investments are made.

V. <u>LONG-TERM CONSIDERATIONS AND OPPORTUNITY ASSESSMENT</u>

Q. WHAT FACTORS ARE IMPORTANT TO CONSIDER FOR LONG-TERM HEDGING PROGRAMS?

A. Long-term hedges should be considered when market conditions offer opportunities to hedge at attractive price levels, to provide long-term rate stability for customers, and to reduce market price risk exposure. A gas reserve investment is a material undertaking from a resource and cost perspective. It is important that the investment make sense as a risk reduction strategy. And since there are long-term rate implications, it should provide sustainable, long-term benefits to customers. If future costs can be stabilized at attractive levels, there is considerable benefit for customers. Avoidance of future price volatility and rising market prices would be valuable. Therefore it is helpful to analyze the relative price value and the impact of natural gas supply and demand market drivers.

Q. WHAT DO YOU SEE AS THE RELATIVE PRICE VALUE OF U.S. NATURAL GAS?

A. Current natural gas prices are at a low point relative to historical prices, low relative to global gas prices, and are forecasted to remain low relative to oil prices. The graph below (Figure 28 from the Report) shows historical natural gas prices compared to two prices. The first is the Base Case Price, a blend of the [redacted]ncreases steadily from 2016 to 2035. The second price is an Illustrative Reserves Price, a theoretical price representative of a potential reserves acquisition where the drilling efficiencies over time exceed the rate of inflation. The graph illustrates a higher starting price for the Illustrative Reserves Price, but this decreases over time because of drilling and production efficiencies:

[redacted])[2]

[redacted]

Q. WHAT ARE THE LONG-TERM SUPPLY DRIVERS YOU EXAMINED?

A. The key supply drivers are U.S. domestic production and U.S. imports of natural gas from Canada.

Q. PLEASE DESCRIBE THE TRENDS IN NATURAL GAS PRODUCTION SUPPLY AND COST?

A. Shale gas technology increased the amount of recoverable North American gas supply, enabling producers to access vast supplies of shale gas. New technology that provided

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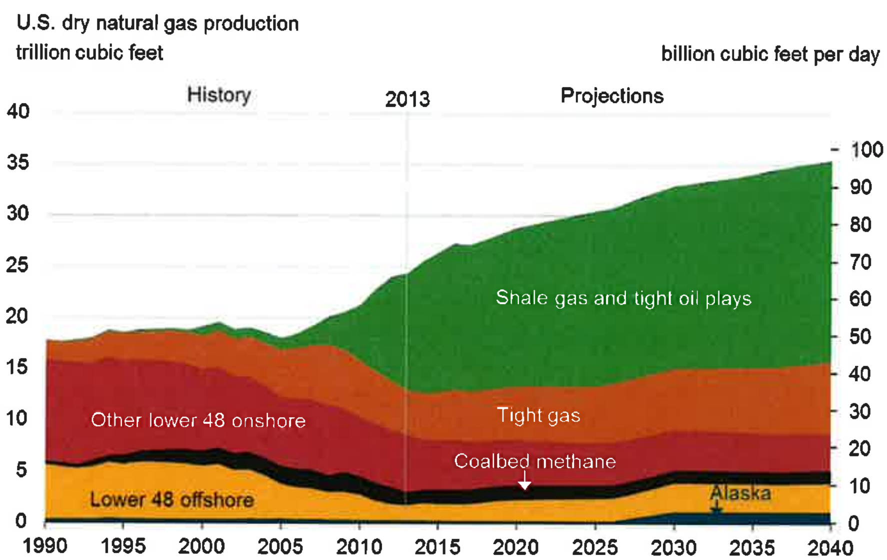
[2] [redacted]

lower cost access to shale gas caused total U.S. production to grow substantially from 2005 to 2013. Figure 2 below (Figure 32 from the Report) shows the historical and future production forecasts for shale gas relative to other production methods.

Figure 2 – EIA U.S. Shale Gas [3]



Source: EIA, Annual Energy Outlook 2015 Reference case

Because shale gas is growing materially in its contribution to total natural gas production and because it has a lower production cost, a break-even analysis of production costs can help define a long-term floor to market prices. In its May 2014 report, Wood Mackenzie's analysis of the major shale plays in North America illustrates break-even prices of \$3.00 - \$5.00 per Mcf for these low cost shale gas resources[4]. This suggests the price cannot go much lower because the market is already close to break-even levels.

Q. PLEASE DESCRIBE THE TREND OF NATURAL GAS IMPORTATION FROM CANADA?

[3] U.S. Energy Information Administration, Center for Strategic and International Studies, *AEO2015 Rollout Presentation*, Adam Sieminski, Administrator, April 14, 2015

[4] David Pruner, Senior Vice President, Wood Mackensize, *North American Natural Gas Market and the Shale Revolution,* May 19, 2014

A. Historically the U.S. has imported significant amounts of Canadian natural gas. But Canada's National Energy Board ("NEB") forecasts continued declining production over the next few years, and then recovery in production driven by shale gas production increases. Canada has less exportable surplus gas to send to U.S. markets if it were needed. This trend is illustrated in the Report in Figure 36 – Canadian Marketable Gas Production.

Q. WHAT PRODUCER METRICS DID YOU REVIEW TO UNDERSTAND THE ECONOMICS OF PRODUCING GAS?

A. I examined two historical metrics to understand the economics of producing natural gas: netback margins and return on equity. Producers' netback margins are composed of gross margin minus royalties, production costs, and transportation expenses. U.S. producers do not publish such a metric, so Canadian producer reporting serves as a proxy for the broader North American producers. Looking at six of Canada's largest natural gas producers, from the period of 2008 to 2014, the group's netback margins were highest in 2008 and then dropped to lows in 2012 when market prices were at their low. For most of the group, the margins have been a little better in 2013-2014, but still the netback margin is significantly below the 2008 levels. The other metric was the average return on equity percentage. I looked at this metric for a peer group of eleven independent natural gas producers. The peer group's average profitability metric of return on equity (%) correlated to the level of annual spot market natural gas prices. It was highest when natural gas prices were at historically high levels, and declined in lower price years. The most recent figures for 2014 indicate that investment returns were not attractive for the sector.

Q: WHAT PROSPECTIVE PRODUCER METRICS IMPACT FUTURE NATURAL GAS PRODUCTION?

A. While netback margins and return on equity ratios provide a historical and current perspective of the relative profitability in natural gas production, looking at producers' capital budgets, rig counts, and reserve replacement ratios provide a forward view of natural gas production trends. With the recent decline in oil and gas prices, there has been a reduction in exploration and production spending. This is supported by an analysis conducted by *Oil & Gas Journal*, comparing 2015 capital investment in different energy sectors to 2014 and 2013 levels.[5] U.S. exploration and production capital spending is forecasted to decline 32% from 2014 levels (which had increased 9% from 2013). Canadian activity is forecasted to decline 30% from 2014 levels (which had increased 7% from 2013). Rig counts and reserve replacement are two other metrics of natural gas production. Examining the number of rig counts allocated to oil and gas production shows shifting exploration and production trends. Recent rig data from Baker Hughes shows that 75% of all rigs in operation today are oil-directed and 25% are gas-directed. That compares to July 2008 when 20% were oil-directed and 80% were gas-directed. Reserve replacement is another metric to track the industry's capital investment and commitment to maintaining, increasing or decreasing investment in crude oil and natural gas reserves. If returns are attractive, reserve replacements should be steady or increasing. In contrast, when investment returns are unattractive, there would be tendency for reserve replacement to decline. Natural gas reserve replacement peaked at

[5] Bob Tipee, Oil & Gas Journal, *Companies slash capital budgets as oil price drop cuts cash flows*, April 6, 2015, Volume 113.4, p 28-34.

268% of annual production in 2010, but declined to minus 34% in 2012 (the recent low in natural gas prices).

Q. WHAT CONCLUSIONS DO YOU DRAW FROM THE HISTORICAL AND PROSPECTIVE PRODUCER METRICS?

A. While production trends are stable, producer profits are not large. Producers are reducing natural gas drilling capital budgets in absolute terms and relative to other investment opportunities such as oil and liquids-rich investments. Recent natural gas reserve replacements are positive but not overwhelmingly large, which suggests that domestic production growth will not increase faster than projected demand. If reserve replacement does not keep up with demand, prices will rise.

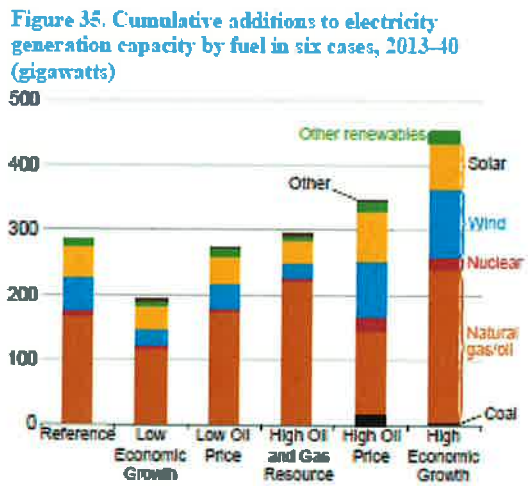
Q. WHAT DID YOU FIND WHEN YOU EXAMINED LONG-TERM DEMAND DRIVERS?

A. On the demand side, I looked at demand growth in electric generation, domestic transportation fuel, and international export of U.S. LNG. The pacing and scale of demand growth is hard to forecast but most forecasts indicate significant demand growth.

Q. WHAT ARE THE TRENDS IN ELECTRIC GENERATION DEMAND FOR NATURAL GAS?

A. As a result of stringent EPA regulation to limit emissions from stationary sources, many generation owners will close old, inefficient coal plants as opposed to investing new capital to comply with environmental regulation. Natural gas is the lowest-cost resource that will comply with these environmental regulations, while offering operational flexibility, large scale capacity, and grid stability. Therefore, most electric generation forecasts reflect continued closure of coal plants and new capacity additions in gas generation and some in renewable energy. The figure below illustrates the growth in natural gas electric generation forecasted by the U.S. Department of Energy's Energy Information Administration ("EIA"), published in its 2015 Annual Energy Outlook ("AEO2015") for its reference case and other forecast scenarios (Figure 45 in the Report):

Figure 3 – EIA's Different Scenarios for Generation by Fuel[6]

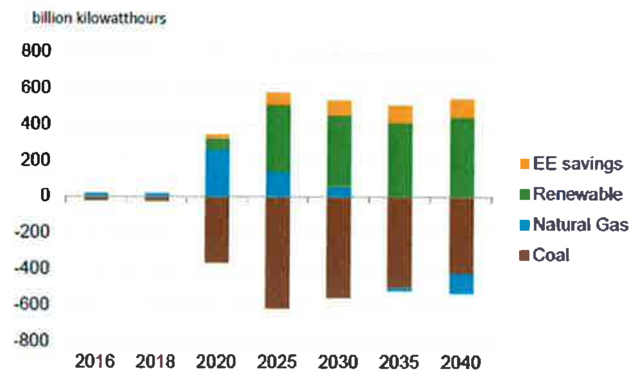


The AEO2015 did not include the effect of the proposed Environment Protection Agency's ("EPA") Clean Power Plan. As a result, the AEO2015 Reference Case likely understates gas demand. As a result, the four natural gas price forecasts may well be higher in a future Annual Energy Outlook based upon the nature of the EPA's Clean Power Plan final regulation. In May 2015, EIA published an analysis showing the effect of the proposed EPA regulation, which is shown in the chart below (Figure 46 from the Report). EIA forecasted the natural gas generation additions would occur primarily in the period of 2020 to 2030.

Figure 4 – Clean Power Plan: Change in Generation for AEO2015 Reference Case[7]

[6] Energy Information Administration, *Annual Energy Outlook 2015 With Projections to 2040*, DOE/EIA-0383(2015), April 2015, 28.

Figure 4. Change in generation and energy efficiency savings under the Clean Power Plan Base Policy case relative to AEO2015 Reference case



Source: U.S. Energy Information Administration.

In August 2015, the final Clean Power Plan was released. Renewable energy is expected to play a larger role than it did in the proposed plan. But at the same time, the 2030 goal for carbon dioxide (CO2) emissions from the power sector to decline was increased from 30% in the proposed plan to 32% in the final plan. The final impacts are not yet known since states have until 2016 to submit their draft proposals to meet the targets and 2018 to submit final plans. But natural gas generation will play a major role in meeting the gaps created by reducing generation from coal-fired plants.

Q. WHAT IS THE IMPACT OF NATURAL GAS TRANSPORTATION FUEL DEMAND?

A. It is very hard to predict the adoption rate of new technologies and the speed of commercialization. There are wide discrepancies in forecasts for natural gas transportation fuel demand. In its AEO2015, EIA forecasts domestic natural gas fuel consumption to grow from 0.9 trillion cubic feet ("Tcf") per year in 2013 to 1.6 Tcf by 2040. This means that in 2013, the domestic natural gas transportation fuel consumption

[7] Energy Information Administration, *Analysis of the Impacts of the Clean Power Plan*, May 2015, p.15.

represented 3% of domestic demand, and is forecasted to grow to 5.5% of 2030 domestic demand. But, in a different forecast, PIRA Energy Group in September 2014 projected that natural gas could take as much as 1.3 million barrels per day of demand away from diesel in the transportation sector by 2030. At a conversion rate of 5.8 MMBtu per barrel, this would equate to 2.75 Tcf per year by 2030. PIRA's 2030 forecast would raise the domestic natural gas transportation fuel consumption to 9.8% of total domestic natural gas demand. Should this sector grow as quickly as PIRA forecasts, it could be material to natural gas prices. Natural gas demand as a transportation fuel can only occur on a large scale when there are fuel savings associated with switching to natural gas, when fueling infrastructure is available, and there is environmental regulation pushing the industry to change. The compelling factors for natural gas conversions from diesel fuel are the fuel cost differential and EPA regulations against emissions. The large price differential between natural gas and refined oil products in combination with environmental regulation is shifting demand to natural gas in the marine, road, and rail transportation sectors. Furthermore, there have been numerous initial investments in infrastructure- both in terms of the engines and the fueling infrastructure to support natural gas transportation fuel demand. These trends are described in more detail in <u>Part 3 – Long-Term Factors and Opportunity Assessment</u> of the Report.

Q. WHAT IS THE IMPORTANCE OF NATURAL GAS EXPORTS WHEN LOOKING AT DEMAND DRIVERS?

A. As North American gas becomes increasingly linked to international markets, supply and demand factors elsewhere in the world will impact U.S. natural gas prices. Therefore, determining where long-term U.S. natural gas prices may go requires insight to global gas market drivers.

Q. WHAT IS CHANGING WITH RESPECT TO EXPORTS TO MEXICO?

A. The U.S. exports natural gas to Mexico through pipelines. In its AEO2015 Reference Case, EIA is projecting continued growth in exports to Mexico from 0.7 Tcf per year in 2013 to 3.0 Tcf in 2040.

Q. HOW SIGNIFICANT MIGHT U.S. LNG EXPORTS BE?

A. I looked at several third-party analyses to review U.S. LNG's competitiveness in international markets. Although there are over 30 countries that currently have LNG liquefaction capability or have announced plans to add liquefaction, the U.S. LNG export sector seems to have several key advantages. U.S. domestic market prices are very low on a global comparison and U.S. projects are "brownfield" facilities with lower project development cost and shorter completion time because many are existing import facilities being turned into export facilities. In contrast to many LNG export countries, the U.S. is more stable economically and politically. Six LNG export facilities have received federal approvals and 8.4 Bcf/day of capacity is under construction. There is an additional 29 Bcf/day of export terminal capacity awaiting approvals by FERC. Many of the LNG facilities have announced LNG export contracts with major international LNG buyers. This indicates a high likelihood of future U.S. LNG exports. The size and scale is hard to determine precisely because of many international supply and demand factors, but the range in forecasts is startling. In its AEO2015 Reference case, EIA forecasted net LNG exports of natural gas of 2.08 Tcf/year (5.7 Bcf/day) by 2020 and 3.29 Tcf/year (9 Bcf/day) by 2030. The forecast remains constant from 2030 to 2040. That would equate to 8.0% of total domestic gas demand by 2020, and 11.7% by 2030 and 11.1% by 2040. In contrast, the Brookings Institute wrote: "We believe that the U.S. LNG projects that are currently under construction totaling close to 10 Bcf/d in capacity, will make it to the market by 2020" (10 Bcf/day of net LNG exports would equate to 14% of domestic demand).[8] Black & Veatch estimated between 10-14 Bcf/day of exports by 2020 based upon the number of FERC and DOE approvals and the announced capacity of the approved facilities,[9] a range of 14% to 19.5% of domestic demand. And, Wood Mackenzie forecasted as much as 6-8 Bcf/day (8.4% to 11.2% of domestic demand) by 2020 and 16-18 Bcf/day (19.7% to 22.1% of domestic demand) by 2040.[10] The U.S. has historically been a net importer of LNG, so the forecasted range in net LNG exports would represent sizeable export demand relative to domestic demand.

Q. WHAT CONCLUSIONS DID YOU DEVELOP IN YOUR QUALITATIVE ANALYSIS OF NATURAL GAS SUPPLY AND DEMAND DRIVERS?

A. I conclude that there is more potential for prices to rise than fall because of the uncertainty in supply growing sufficiently to meet demand. Moreover, prices are close to a break-even point today, which may have occurred because the market has been more of a supply-driven market since 2009. But going forward, it appears there will be a shift to a more demand-driven market. If this proves to be the case, current production trends may be insufficient to meet potential demand growth, suggesting that natural gas prices are likely to rise. This is supported by the aggregated supply and demand factors from the Report in the table below (Figure 3 from the Report):

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[8] Brookings Institute, Natural Gas Issue Brief #4: *An Assessment of U.S. Natural Gas Exports*, Brookings Energy Security and Climate Initiative Natural Gas Task Force, July 2015, P 14.
[9] Black & Veatch, *2014 Strategic Directions: U.S. Natural Gas Industry*, 2014, 36.
[10] David Pruner, Senior Vice President, Wood Mackenzie, *North American Natural Gas Market and the Shale Revolution,* May 19, 2014

Figure 5 – Factors Supporting Long-Term Hedging

Customer Price	Gas production hedging can stabilize rates for customers at reasonable costs relative historical costs, particularly during the current relatively low-price environment
Historical Price Context	Recent historical low gas prices may not continue and may well revert to higher prices seen historically because of new gas demand
Crude Oil vs. Natural Gas	Despite lower crude oil prices, many producers still prioritize crude exploration and production over natural gas; U.S. LNG contracts may be shifting from a crude oil benchmark to blend of crude oil and natural gas benchmarks
Break-even Cost	Current market price is not substantially higher than the break-even cost for shale production
Gas Production Trends	Low producer profitability, shrinking capital investment in gas drilling and modest gas reserves replacement trends indicate prices may need to rise to encourage greater investment
Net Imports	Canada has less exportable surplus to send to the Lower 48 states and Mexican demand is forecasted to continue to grow
Transportation Demand	North American demand is growing through expanding CNG/LNG transportation demand
Environmental Regulation	Current and proposed regulation would result in still more gas generation and renewable energy additions
Comparative Pricing	Natural gas is attractively priced relative to other energy sources
U.S. Gas Prices	U.S. natural gas is attractively priced to destination LNG markets
LNG Plants	U.S. brownfield LNG export terminals have a cost advantage compared to greenfield plants elsewhere and a number of facilities have already received approvals
LNG Contracting	Most of the approved LNG export capacity has associated long-term contracts with large international LNG traders and consumers

Even though Lower 48 production increases are forecasted, decisions by large independent producers to reduce capital in gas production and in some cases, to shift from gas production investment to oil production, indicates gas production economics are not very attractive for producers at current gas prices. Also, Canada does not offer the same low-cost ample supply as it used to, as its exportable surplus continues to decline.

Demand fundamentals appear to be changing, so gas prices may need to rise higher than the Base Case forecast to spark more production to meet the projected future demand. From a demand perspective, there is new gas demand emerging from the retirement of coal plants, the domestic transportation demand for LNG and CNG, and the increase in North American exports (pipeline gas to Mexico and LNG to other countries).

VI. PORTFOLIO MODELING

Q. WHAT WAS THE PURPOSE OF THE PORTFOLIO MODELING?

A. The purpose of the modeling was to see the effect of long-term hedging under varying forward market price scenarios and different hedging scenarios. This type of quantitative analysis is important to consider in addition to the qualitative analysis. It is important to conduct portfolio analysis in order to understand the implications of expanding a utility's hedging program.

Q. PLEASE DESCRIBE THE MODELING OF THE GAS SUPPLY PORTFOLIO.

A. Aether's Portfolio Model was developed to show results in average gas supply costs as well as in net present value terms. The time horizon is a twenty-year time period from 2016 to 2035. The discount rate used was 7.72% to convert the nominal gas supply costs into a net present value amount.[11] In order to model the gas requirements, Aether used BHUH's natural gas demand forecast and annual load growth factors for the period of 2016-2035. The six hedging scenarios represented a range of hedging percentages to manage price risk (please see Figure 63 of the Report for graphs depicting each scenario):

- Scenario 1 - Current Hedging Plan

[11] Consistent with the proposed COSG Program, Aether applied a blend of 60% equity based upon an estimated allowed return on equity of 9.86% and 40 percent long-term debt cost of 4.5% for a weighted cost of capital of 7.72%.

- Scenario 2 - Current Hedging Plan and Gas Reserves starting at 18% in Year 1 and rising to 34% by Year 11 and staying at 34% through Year 20
- Scenario 3 - Short-term, Medium-term and Gas Reserves 35% long-term
- Scenario 4 - Short-term, Medium-term and Gas Reserves 50% long-term
- Scenario 5 - Short-term, Medium-term and Gas Reserves 60% long-term
- Scenario 6 - Short-term, Medium-term and Gas Reserves 75% long-term

Q. WHAT WAS THE ASSUMED HEDGING PRICE TO COMPARE TO THE PRICE SCENARIOS?

A. The starting assumption was that short-term hedges would be acquired at the Base Case Price scenario, whereas the long-term gas production was hedged at an Illustrative Reserves Price, the theoretical example that has been filed as Exhibit AC-2 to Aaron Carr's direct testimony. For each of the six hedging scenarios, the un-hedged volumes were then assumed to be purchased at a given price scenario. There were ten price scenarios used to develop a range of gas supply cost for each of the six hedging scenarios.

Q. PLEASE DESCRIBE THE TEN PRICE SCENARIOS USED IN THE MODEL?

A. The six hedging scenarios were stress-tested using ten natural gas price scenarios intended to show a reasonable range of potential outcomes. The price scenarios were all put into nominal dollar terms (in unadjusted dollars) to reflect the then current value:

[redacted] Base Case Price scenario, [redacted]

- Four natural gas price forecasts from EIA's Annual Energy Outlook 2015 titled "Reference" case, "High Oil Price" case, "Low Oil Price" case and "High Oil and Gas Resource" case
- One natural gas price forecast from EIA's Analysis of the Impacts of the Clean Power Plan, May 2015, "Clean Power Plan Base Policy (CPP)"
- [redacted]
- Extreme High price scenario that is two times the Base Case price scenario (nominal dollars)[12].

The Illustrative Reserves Price and the ten price scenarios are illustrated in the graph below in nominal dollars (Figure 1 from the Report) and are described in Appendix B – Detailed Explanation of Forward Price Scenarios in the Report:

[12] The Extreme High Price scenario is not a forecast, but a price scenario Aether added to incorporate price escalation, based upon historical price appreciation in the period of 1988 to 2008, prior to the shale gas production expansion. This price scenario tests the potential impact on gas supply costs if the forward market price appreciated at a rate of growth seen in historical periods.

[redacted]

[redacted]

Q. HOW WAS THE REGIONAL PRICING FOR THE UTILITIES HANDLED?

A. While some of the short-term hedges were valued at Henry Hub, other elements of the utilities' portfolios, such as load and storage, needed to be valued at regional pricing differentials to Henry Hub. The load service area was divided into regions and three forward regional price locations were developed: (a) Colorado, (b) Northern Natural Gas Ventura, and (c) Southern Star.

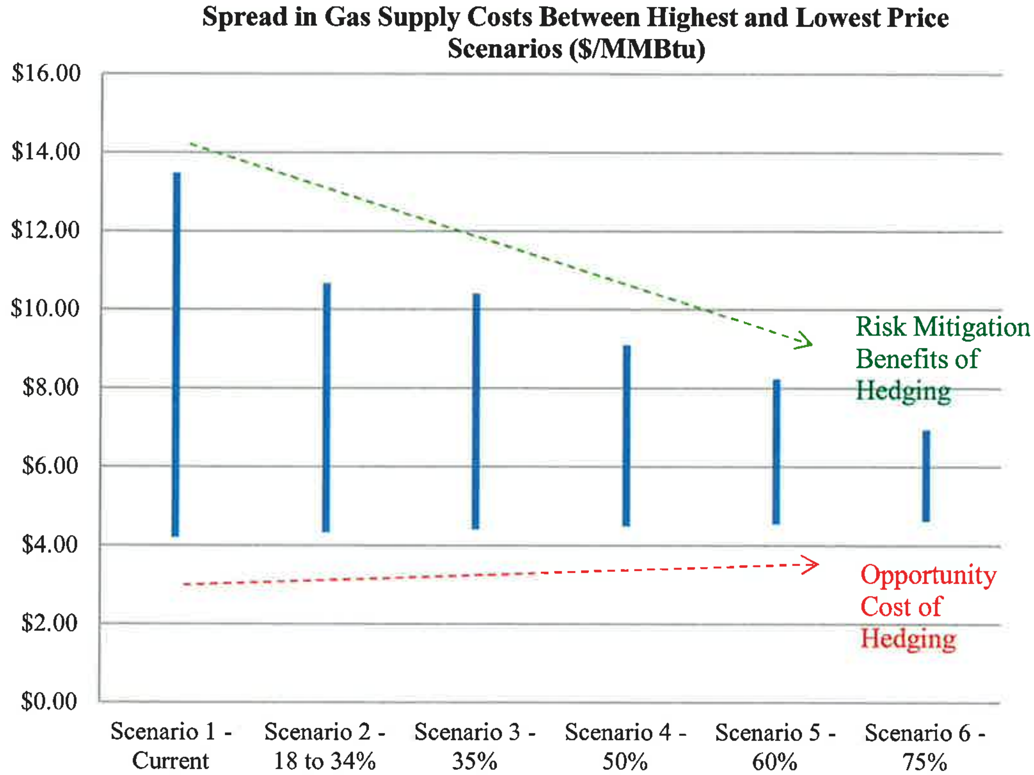
Q. PLEASE DESCRIBE THE REASONING FOR INCLUDING THE EXTREME HIGH CASE PRICE SCENARIO.

A. Natural gas markets have historically exhibited long-term "bull market" trends (rising prices) and "bear market" trends (declining prices). The market has been in an extended bear market trend since annual natural gas prices peaked in 2008. I believe this to be the result of a supply-driven market where the new sources of supply exceeded the demand for natural gas at the time. As such, I believe it is important to include a price scenario that is more reflective of the market before the financial crisis and the implementation of new shale gas extraction technology. Aether examined the compounded annual growth rate ("CAGR") in gas prices in the period of 1998 to 2008, prior to the financial crisis and shale gas technology shift. Aether noted the CAGR over the twenty-year period of 1988 to 2008 was 8.06%, while the CAGR for the ten year period of 1998 to 2008 was significantly higher at 15.54%. [redacted] But that period included very slow growth in the first decade with far greater growth in the second decade. Therefore, Aether elected to include an Extreme High Price scenario at two times that of the Base Case Price scenario, for this had a CAGR of 9.78%. This is not Aether's price forecast or prediction for the future, but rather a scenario worth considering among a range of price scenarios.

Q. WHAT WERE THE RESULTS OF THE PORTFOLIO MODELING?

A. The results from the portfolio modeling are shown in the figure below. The candlestick chart (vertical lines) depicts the range in gas supply costs for each hedging scenario. The higher the percentage hedged of the portfolio, the narrower the spread in gas supply costs across all the price scenarios. This illustrates that the higher the percentage hedged, the more stable customer gas supply costs. The chart is also helpful for viewing the trade-off between price mitigation and potential opportunity cost. The green arrow directionally shows the mitigation achieved with greater percentages of hedging – the higher the hedging percentage, the greater the mitigation against the higher price scenarios. The red arrow directionally shows the potential opportunity cost of hedging greater percentages of the portfolio – the higher the hedging percentage, the more potential opportunity cost.

Figure 7 – Graphical Results of the Portfolio Modeling (Average Cost)



Opportunity cost represents the difference between the hedged cost and lower market prices (represented by the lower price scenarios). The opportunity cost in the portfolio modeling is much smaller than the risk mitigation achieved. This is because the Illustrative Reserves Price scenario is a low price relative to all but two of the other price scenarios in the model and the difference between those and the Illustrative Reserves Price scenario is not large. The numerical values for the range in gas supply costs resulting from the six hedging scenarios are illustrated in the table below.

[redacted]

[redacted]

The table summarizes the twenty-year gas supply cost on an average cost. The greatest range in potential gas supply cost occurs in the first hedging scenario representing BHUH's current hedging program. The spread between the highest and lowest gas supply outcome is $9.27 / MMBtu [redacted] scenario compared to $13.46/ MMBtu in the Extreme High). In contrast, this spread narrows considerably to $2.33/MMBtu in the highest hedging scenario of 75% long-term production [redacted] scenario compared to $13.46/ MMBtu in the Extreme High). Based upon the portfolio modeling results, long-term hedging offers more rate stability over time and provides mitigation against rising market prices. The higher the volume hedged long-term, the more narrow the range in gas supply costs and the greater the price protection.

Q. WHAT CONCLUSIONS DID YOU DRAW FROM MODELING THE ILLUSTRATIVE RESERVES?

A. The combination of the reserves acquisition cost and production costs result in a lower net present value gas supply cost than all but two of the ten price scenarios. And it was only somewhat higher than those two lower price scenarios. This occurs in large part because the reserves are acquired in the current low-priced market environment and the compounded annual growth rate (CAGR) in production costs is -1%, a marked contrast to the other price scenarios that have a CAGR of 2.95% to 9.78%. But it should be noted that even this is a conservative modeling approach for reserves. COSG Program acquisition of producing reserves would be similar to a fixed price contract with volumes declining over time, but the incremental production that comes from drilling new wells is more akin to a long-term call option. The Company would have the opportunity to participate in new drilling under the COSG Program. If forward prices did not justify additional drilling, the Company would not participate in additional drilling. This flexibility would not be present in a fixed price contract.

Q. WHAT CONCLUSIONS DID YOU DRAW FROM THE QUANTITATIVE ANALYSIS OF THE LONG-TERM PORTFOLIO?

A. Based upon the portfolio modeling results, a strategy to hedge long-term gas prices would narrow the range in potential gas costs, thereby offering greater rate stability. The quantitative analysis also illustrated that the higher the percentage hedged, the more protection provided to the Company's customers against rising market prices.

VII. REPORT CONCLUSIONS AND RECOMMENDATIONS

Q. WHAT WERE YOUR PRIMARY CONCLUSIONS?

A. Aether was asked to consider if a long-term hedging program made sense for BHUH to execute and if it did, what would be an appropriate amount of hedging and how could the long-term hedging be integrated with the current hedging program? To do this, I assessed BHUH's hedging objectives and current hedging program; reviewed the COSG proposed structure; considered long-term market price dynamics; and examined the impact of long-term hedging on BHUH's portfolio. Based upon my analysis, I developed the following primary conclusions:

1. BHUH's hedging objective to provide rate stability for customers does not extend beyond one to two winter seasons except for one of its utility jurisdictions (Colorado electric). The current short-term program does not provide enough risk mitigation to achieve the objective to provide long-term rate stability and protect customers from market volatility.
2. The portfolio modeling confirmed that hedging would narrow the variability in future rates, providing rate stability for customers, consistent with BHUH's hedging objectives. Further, hedging through natural gas reserves provides against market price exposure. The analysis demonstrated more potential upside risk than downside risk relative to the ten price scenarios.
3. The market fundamentals point strongly toward demand rising faster than supply. Natural gas prices will need to rise to drive supply growth to meet demand growth.
4. There are compelling reasons for BHUH to consider long-term hedging. Current natural gas prices are not only low relative to historical prices, but are also low compared to alternative fuel prices and global gas prices. There appears to be an opportunity to stabilize long-term gas costs at attractive price levels for

customers. And there is uncertainty regarding long-term supply and demand that warrants looking at opportunities to lock in gas supply costs for customers.

Q. WHAT DID YOU RECOMMEND IN YOUR REPORT?

A. On an annual basis BHUH hedges 27% to 55% of the utilities' gas requirements for the upcoming winter using storage, short-term fixed price, and call options. I recommended that BHUH increase the percentage hedged short-term and that it expand its hedging program to include medium-term and long-term hedging to add rate stability over multiple rate years. The forward market fundamentals point to prices rising as a result of growing natural gas demand. A gas reserves acquisition based upon current market dynamics would provide an opportunity to protect against the risk of rising prices and to reduce the potential range in future gas supply cost.

Q. WHAT INTEGRATED PORTFOLIO RECOMMENDATION DID YOU PROVIDE?

A. The size and scale of a hedging program should be driven by the risk exposure the utility and its regulators want to mitigate within the supply portfolio and what opportunities are present to manage risk. Aether recommended an integrated approach to incorporate the long-term hedging with BHUH's current hedging strategy. The gas supply objective to provide a high level of reliability is well met with the flexibility of storage and the use of call options. Both of these allow the utility to adjust its gas supply portfolio for changes in weather patterns that would impact loads. The two gas supply objectives to provide reasonably priced natural gas and mitigate price volatility would be well met through the acquisition and production of reserves.

Q. DID YOU PROVIDE A RECOMMENDATION IN TERMS OF HOW THIS INTEGRATED PORTFOLIO SHOULD BE DETERMINED?

A. Yes. The starting point is to develop a long-term target for reserves, using both qualitative and quantitative analysis. Following this, the short-term and medium-term instruments would be layered in to provide greater short-term market risk mitigation. Aether recommended that BHUH stage its acquisitions, with an overall goal of acquiring a minimum of 35% long-term gas supply with an objective of up to 50% coverage.

Q. WHY IS "UP TO 50%" COVERAGE PART OF YOUR RECOMMENDATION?

A. The range in percentage of hedging with gas reserves among other utilities is quite varied- ranging from 15% by Sacramento Municipal District to 65% by Questar-Wexpro. My "up to 50%" recommendation for reserves acquisition is based upon several factors. First, the COSG Program is worth proceeding with if there is a meaningful size and scale. It takes a great deal of management time to execute and manage this effort, as well as Commission time to review proposed acquisitions and drilling plans. A more significant program also is more likely to bring economies of scale, making the gas supply cost more attractive for customers. Additionally, the effort involved would not make sense to pursue if it did not provide meaningful hedging protection to customers.

Q: WHY NOT RECOMMEND A HIGHER PERCENTAGE OF HEDGING LONG-TERM IN THE GAS SUPPLY PORTFOLIO?

A. On one hand, increasing the hedging percentage narrows the range in gas supply costs. But, while a higher percentage would provide additional rate stability and confidence around the gas supply cost, there is a point where committing to high percentage of gas reserves leaves little room for future portfolio management flexibility or innovation in the future. For example the combination of 75% hedged and storage would aggregate to close to 100% for the upcoming winter, leaving no opportunity to use other tools such as call options.

Q. WHAT DISTINGUISHES BHUH'S COSG PROGRAM FROM OTHER GAS RESERVES PLANS?

A. There are two key differences. First, BHUH has the benefit of the knowledge and expertise of an exploration and production affiliate, which is unusual among gas and electric utilities. This expertise will help BHUH to understand key valuation drivers and to mitigate risks, reducing costs for customers. Second, unlike other utility reserve acquisition programs with which I am familiar, BHUH is proposing a performance benchmark that should further reduce the risk for customers and align interests between customers and the shareholders. BHUH is proposing that the COSG Programs' allowed return on equity ("Allowed ROE") be decreased by 100 basis points if there is a Hedge Cost associated with the production, thereby placing risk on BHUH and decreasing costs for customers. Given that the COSG Program's Allowed ROE would currently be 9.86%, this would represent a potential penalty of ten percent of its Allowed ROE, which is not inconsequential from a percentage standpoint. The proposal has an incentive on the other side by increasing the Allowed ROE by 100 basis points if there is a Hedge Credit.

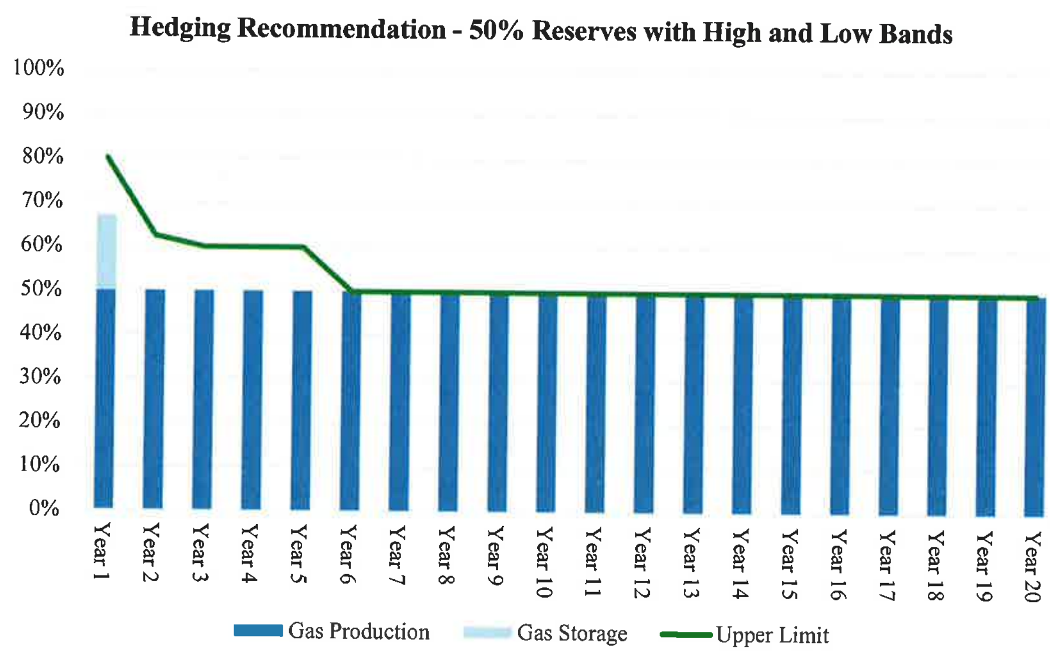
Q. GIVEN THIS LONG-TERM HEDGING RECOMMENDATION, HOW SHOULD BHUH ADAPT ITS SHORT-TERM HEDGING?

A. BHUH should consider the gas reserves as the base of its hedging program, upon which short-term and medium-term hedges can be layered. It would set hedging targets by year that combined reserves with short-term and medium-term hedges. It is conventional in utility hedging programs to hedge a higher percentage in the first year and for the percentage to decline in future years. Therefore, Aether recommends a staggered approach looking forward into the future, where the percentage of hedging declines over time. For example, in Year 1, BHUH would have short-term, medium-term and long-term hedges in place to aggregate to a target amount. The hedging amount for Year 2 would include medium-term and long-term production aggregating to a lower target than Year 1. The decline would similarly apply for Years 2-5 with declining percentages each year, until Year 6 where the gas production would be the only forward hedge. This would be done on a rolling basis, so that at any given point in time, the utility's hedging plan would have this shape looking forward into the future. As one year rolled off, then new short-term and medium-term hedges would be executed to maintain the hedging plan targets.

Q. WHAT TYPE OF HEDGING PLAN FLEXIBILITY DO YOU RECOMMEND BY YEAR?

A. In the Report, Aether suggested that instead of having fixed targets for hedging, BHUH have some discretion to adjust short-term and medium-term hedges within a pre-determined range based upon changing market conditions. The range would be set with a minimum level and a maximum level by year, and BHUH would hedge between the minimum and maximum levels based upon forward fundamental and technical market analysis. In terms of where the minimum and maximum target levels would be set, the reserves production and the storage commitments would be the minimum amount. The maximum amount would include additional call options and short-term fixed price contracts. In terms of prioritization, storage is a critical balancing tool for short-term demand variability and should be maintained to provide operating reliability, system flexibility, and winter peaking price protection for customers. After the gas reserves and the gas storage, the call options would be the next priority. I recommended BHUH continue to use call options (or no cost collars when appropriate) as a discretionary additional hedge to insure against short-term price spikes during winter months. The lowest priority for additional short-term hedging would be short-term fixed price, since the gas reserves production serves as a fixed price hedge in the short-term. The graph below illustrates the proposed hedging plan using a 50% target. The minimum amount is shown in the stacked bars and the maximum is shown as a line above the stacked bars:

Figure 9 - 50% Reserves Portfolio Recommendation



Q. WHAT SHORT-TERM AND MEDIUM-TERM STRATEGY SHOULD BE PURSUED WHILE LONG-TERM GAS PRODUCTION IS BEING ESTABLISHED?

A. With each subsequent acquisition, the Company would rely increasingly less on short-term and medium-term hedging. The graphs for scenarios 1-6 (Figure 63 of the Report) help illustrate the type of changes that could unfold in BHUH's short-term and medium-term hedging over time. As COSGCO entered into new acquisitions, the Company could submit a revised short-term and medium-term hedging plan to the Commission, illustrating how hedges for the next one to five years would be integrated with the natural gas production.

VIII. CONCLUSION

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

Public Version Exhibit
JMR-1-Gas Supply
Portfolio Design

Black Hills Corporation
Improving life with energy

PUBLIC VERSION

[redacted]