BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF SOUTH DAKOTA

In the Matter of the Application of Black Hills Power,	**)**	
Inc. for Approval of Tariff Revisions Related to its	**)**	**Docket No. EL15-036**
Cost of Service Gas Agreement with Black Hills	**)**	
Utility Holdings, Inc.	**)**	

TESTIMONY OF BASIL L. COPELAND JR.
ON BEHALF OF
THE COMMISSION STAFF

July 11, 2016

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I. BACKGROUND AND QUALIFICATIONS

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Basil L. Copeland Jr. and my business address is 14619 Corvallis Road, Maumelle, AR, 72113.

Q. WHAT IS YOUR OCCUPATION, BY WHOM ARE YOU EMPLOYED, AND FOR WHOM ARE YOU TESTIFYING?

A. I am an economist, specializing in energy and utility economics and a principal in Chesapeake Regulatory Consultants, Inc., Annapolis, MD. I am testifying on behalf of the Staff of the South Dakota Public Utilities Commission.

Q. PLEASE DESCRIBE YOUR EDUCATION AND PROFESSIONAL EXPERIENCE.

A. I received my education at Portland State College (1967-1969), New Mexico Institute of Mining and Technology (1969), and Oregon State University (1972-75). In 1974 I received a Bachelor of Science degree in Economics from Oregon State University and in 1976 a Master of Science degree in Resource Economics (with a minor in Business Finance) from the same institution.

From August 1975 to February 1977 I worked as a financial analyst and staff economist for the Arkansas Public Service Commission. From March 1977 to August 1978 I worked in a similar position for the Iowa State Commerce Commission. In September of 1978 I went to work for the Attorney General of Arkansas in a U.S. Department of Energy-funded office of consumer services with responsibility for economic analysis in electric utility rate cases. While with the Attorney General I assisted in the development of legislation that created the Arkansas Department of Energy. In July of 1979, soon after the Department was officially created, I became Deputy Director for Forecasting. In that position I directed a staff with broad responsibilities that included the development of an energy management information system for monitoring energy supply and demand in Arkansas, including comprehensive forecasts of energy demand by fuel source and sector.

I left the Arkansas Department of Energy in January 1981 and worked briefly as an independent consultant before joining the consulting firm of Hess and Lim, Inc. in April 1981. While employed by Hess and Lim I served as a consultant on numerous rate cases before the FERC and various state utility commissions. I left Hess & Lim in October 1986 to join with two other consultants in the founding of Chesapeake Regulatory Consultants. I have testified or provided technical assistance in over 150 proceedings before the FERC, the FCC, and regulatory bodies in: Alabama, Arizona, Arkansas, California, Colorado, Georgia, Illinois, Iowa, Kansas, Maine, Maryland, Mississippi, Montana, New Jersey, New Mexico, New York, Oklahoma, Pennsylvania, Rhode Island, South Dakota, Texas, Vermont, Washington State, West Virginia, and the District of Columbia. On four occasions I have been invited to appear on the program of the annual conference of Michigan State University's Institute of Public Utilities and I have served as faculty for the Michigan State-NARUC summer training program for regulatory commission personnel.

I have published numerous articles, set forth in Appendix A, on a variety of utility issues, including articles or comments in *Land Economics, American Economic Review, Public Utilities Fortnightly, Journal of Business Research, Yale Journal on Regulation, Journal of Portfolio Management, Energy Law Journal,* and the *Financial Analysts Journal*. My 1982 article in the Financial Analysts Journal on the equity risk premium received a Graham and Dodd award from the *Financial Analysts Federation*. I have also served as an academic referee for two academic journals where I reviewed articles on utility economics and finance. My article in the Spring 1991 issue of the *Energy Law Journal*[1] dealt with the

[1] "Procedural vs. Substantive Economic Due Process for Public Utilities," with Walter Nixon. ***Energy Law Journal*** 12 No. 1 (Spring 1991): 81-110.

constitutional standards for due process as applied to utility ratemaking under the celebrated Hope case. It presented a comparative analysis and critique of the 1989 Duquesne decision.[2] A list of publications is provided at the end of my testimony.

II. OVERVIEW OF TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. This is a filing by Black Hills Power, Inc. ("BHP"), a subsidiary of Black Hills Corporation ("BHC" or "BKH"), to revise its Fuel and Purchased Power Agreement (FPPA) to include costs incurred by BHP under a Cost of Service Gas (COSG) Program intended for the purported purpose of providing a long-term "physical hedge" against instability in gas prices. Under the COSG Program, Black Hills Utility Holdings, Inc. ("BHUH") would own and oversee a new entity, COSGCO, which would acquire gas reserves and administer the COSG Program, allocating costs and credits to each utility in the program. The purpose of my testimony is to present the results of my analysis of the proposal and to make a recommendation on whether or not the proposal should be approved by the Commission.

Q. PLEASE SUMMARIZE YOUR CONCLUSIONS AND RECOMMENDATION.

A. Based on the evidence presented in my testimony I conclude this program will not achieve the alleged benefits that purport to justify it. On the contrary, I conclude that the program shifts most of the costs and all of the risks associated with natural gas exploration and production onto ratepayers in exchange for the promise of a benefit that is unlikely to materialize. Consequently, I recommend that the request to approve this program be rejected.

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[2] Federal Power Comm'n v. Hope Natural Gas, 320 U.S. 591 (1944); Duquesne Light Co. v. Barasch, 488 U.S. 591 (1989).

Q. PLEASE DESCRIBE HOW YOU HAVE ORGANIZED THE REMAINDER OF YOUR TESTIMONY.

A. I have organized the remainder of my testimony into three sections. In Section III I discuss the economic issues associated with the COSG Program and demonstrate how they shift costs and risks to ratepayers in return for little or no benefits. In Section IV I review a specific aspect of the proposal with respect to a proposed methodology for determining the allowed rate of return on equity (ROE) to be recovered under the COSG Program. If my recommendation based on the evidence presented in Section III is adopted, the issue of how to determine the allowed ROE is moot. Section V responds to Supplemental Testimony filed by the Company, and Section VI concludes the testimony.

III. ANALYSIS OF THE PROPOSED COSG PROGRAM.

Q. PLEASE EXPLAIN FURTHER WHAT BHP IS PROPOSING IN THIS DOCKET.

A. BHP is proposing a “cost-of-service gas” program in which an affiliate will acquire and develop natural gas properties, sell the hydrocarbons from those properties in competitive markets, and flow excess returns or losses of that affiliate through its Fuel and Purchase Power Adjustment (FPPA) to its utility ratepayers. In the words of Mr. Ivan Vancas, Vice President of Operations Services for Black Hills Corporation:

> The COSG Program is designed to be a long-term hedging program to reduce the Company’s customers’ exposure to the volatility of gas prices, to provide long-term price stability through a physical hedge, and to provide an opportunity for customers to pay less than market prices over the long term. [Vancas Direct Testimony, Page 5, Lines 4-7.]

On its own terms as stated by Mr. Vancas, this program is destined to fail.

Q. WHY DO YOU SAY THAT?

A. I say that because it has as a stated goal something that is impossible in competitive markets: paying less than market prices over the long term. To explain that, we need to understand a little more how the program will work. Under the program, ratepayers guarantee COSGCO a return on equity that falls within a deadband of 100 basis points of an allowed return on equity. I will discuss problems with how that allowed ROE is proposed to be determined in Section IV, but here assume that it is 9.5 percent. Under the program, and subject to all its provisions about what costs are included in calculating ROE, COSGCO would be guaranteed an ROE of 8.5 percent to 10.5 percent. If it earns less than 8.5 percent ratepayers make up the shortfall through a "hedge cost" flowed through the FPPA. If it earns more than 10.5 percent, the excess return flows through the FPPA as a "hedge credit." Clearly, ratepayers benefit only when COSGCO earns more than 10.5 percent. And this will occur only if COSGCO can consistently produce excess returns, i.e., hedge credits exceed hedge costs over the long term.[3]

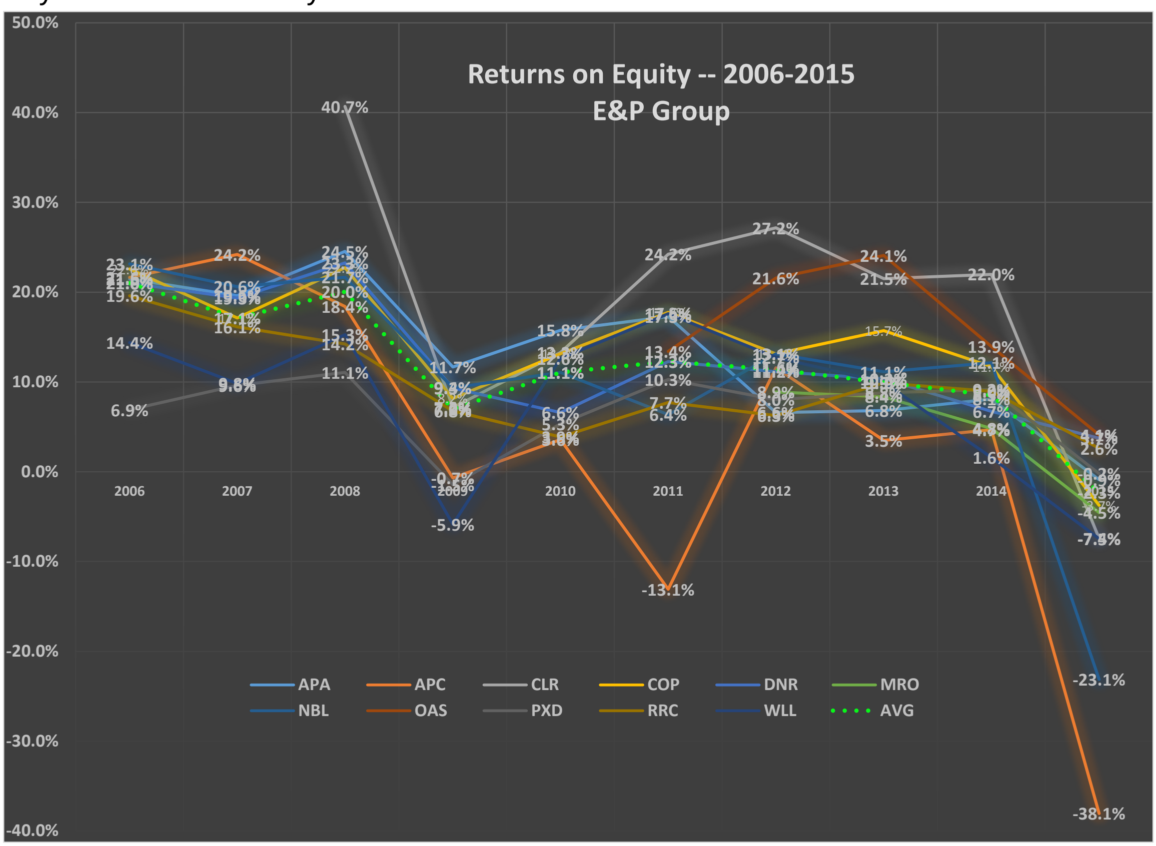
Q. HOW LIKELY IS THAT?

It is not likely at all. BHP wants the Commission to believe that COSGCO can "beat the market." The term "beat the market" refers to earning excess returns in relation to the normal risk adjusted return expected on an investment. In both financial markets and product markets this is impossible over the long run if markets are competitive. Excess returns can exist in the short term for a variety of reasons, but if they persist competition insures that they eventually dissipate. Moreover, the kinds of things that can create short term excess returns are just as likely to produce economic losses so that over any extended period of time the two cancel out, leaving investors with zero excess returns.

A good indication of this here is the history of return on equity earned by the companies making up BHP Witness Mackenzie's "E&P Group." This is a group of petroleum

[3] This assumes the distribution of hedge costs and credits is random over time. If costs are front loaded such that hedge costs occur in early years and hedge credits in later years, hedge credits would have to offset hedge costs so as to make the net present value (NPV) of the stream of costs and credits zero.

exploration and production companies with risk characteristics typical of what COSGCO would be facing and used by Mr. Mackenzie to justify the capital structure proposed for COSGCO. Exhibit___(BLC-1), Schedule 1 shows the range and variation of equity returns for this group for a ten year period, 2006-2015. It exhibits a slight survivorship bias in that I have omitted from the group Ultra Petroleum Corp., which recently filed for bankruptcy. This bias thus overstates the earned returns of the group. But that doesn't affect what we can conclude from the data. On the contrary, it confirms what should be obvious: this is a highly risky and volatile industry.



The chart above illustrates the range and variation of returns on equity for the "E&P Group." The absolute range over the ten years examined varied from a high of 40.7 percent to a low of ***negative*** 38.1 percent.

The median ROE for the entire group over the full 10 year period examined was 11.3 percent. I will show below that this is a reasonable estimate for a risk adjusted ROE for these companies. It is an indication of the volatility of this industry to examine how close the individual companies come to staying within a deadband of 100 basis points of an 11.3 percent return. As shown below (and in Exhibit____(BLC-1), Schedule 1), ROE's fell within a deadband of 100 basis points around the 11.3 percent median ROE 11.34 percent of the time. They fell below the deadband 47.42 percent of the time, and above 41.24 percent of

"Deadband Analysis"
10.3% to 12.3%

Below	Within	Above
4	1	5
6	1	3
2		6
2	1	7
4	3	3
4		
3	3	4
1		4
8	2	
7		3
5		5

	Below	Within	Above
Outcomes in % of Total Years:	47.42%	11.34%	41.24%

the time. This result is hardly surprising given the volatility of returns common in this industry. And there is no reason to believe that COSGCO is likely to do any better. If we take overall industry performance as a guide here, hedge credits are just as likely to be offset by hedge costs, so that there is no long term benefit to ratepayers.

Q. MR. VANCAS SAYS THE PROGRAM IS DESIGNED TO PROVIDE LONG TERM PRICE STABILITY. HOW LIKELY IS THAT?

A. That is just as unlikely as hedge credits significantly exceeding hedge costs over the long term. The range of variation in ROE's in this industry is large. (This is further evident from their stock betas, discussed below.) All but three companies experienced years in which their ROE was ***negative***. Two companies experienced a negative ROE in two of the ten years, and another in three of the ten years. Returns of less than 5.65 percent, half of the 11.3 percent used as the expected ROE in this case, occurred 21.6 percent of the time. Extrapolating this to the COSGCO program, we should expect there to be very large hedge costs in roughly 1 out of every 5 years. This is not the recipe for rate stability.

Q. DOES THIS IMPLY AN INCREASED RISK EXPOSURE FOR RATEPAYERS?

A. Yes, it does. This program is more or less designed to shift risk from BHC's operations in what is otherwise a highly volatile and risky business segment to utility ratepayers. This is the way it has been presented to financial and industry observers, and this is how they perceive it. After BHC's "Analyst Day" presentation on October 8 last year NGI's Shale Daily reported:

> Black Hills CEO David Emery told the company's annual analyst meeting in New York City that low oil and gas prices have had a "pretty big negative impact" on the company and continue to do so. "That being our one market-exposed business, we have been hit pretty hard. The operating losses in our E&P unit this year are not good."
>
> However, Emery said from a strategy standpoint the company "has remedied" the red ink situation by focusing on cost-of-service gas reserves program using its Mancos Shale play in the Piceance. "That gets us out of a heavy dependence on product prices," he said.
>
> "With our Mancos Shale gas play we think we have a huge resource, and that is way more than we need even for cost-of-service gas," Emery said, adding that the utility reserve program would involve about 750 Bcf of reserves, or less than 20% of the estimated reserves in the Mancos. "We have a lot of testing under our belt; we've learned a lot about the Mancos, and we think we can transfer that into a very successful gas procurement program for our utilities." [Full report in Exhibit____(BLC-2).]

The COSG Program is closely tied with BHC's need, as far as the investment community is concerned, with reducing its exposure to operating losses in its E&P unit. However, rather than remove that risk by getting out of the E&P business altogether, it has designed the COSG Program to shift the risk to ratepayers. To borrow from what Mr. Emery said, it gets

BHK "out of a heavy dependence on product prices" by shifting that risk almost entirely to ratepayers. Under the COSG Program, the only risk BKH is exposed to is a possible 100 basis point loss of return on equity.

It bears noting how this COSG Program is poorly presented by the Company to industry and financial analysts, and thus poorly understood by them. CEO Emery's comments here could be taken to imply that "cost-of-service gas" refers to reserves being acquired for its utility customers. In a Fitch Ratings report for BHC issued after the SourceGas acquisition, they say:

> Cost of Service Gas Program: BKH's proposed cost of service gas program would be beneficial to credit quality and would largely offset the risk associated with the increased leverage from the SGH acquisition. If approved by state regulators, the cost of the service gas program would ***materially lower the risk of BKH's natural gas exploration and production business*** while also adding stability to the utilities' fuel costs. ***BKH's utilities would procure 50% of their annual gas consumption through long-term contracts tied to the company's natural gas production costs***. BKH recently submitted cost of service gas regulatory filings in CO, IA, KS, NE, SD, and WY, and the SGH acquisition roughly doubles the amount of natural gas that could be contracted under this program. [Emphasis supplied. Full report in Exhibit____(BLC-3).]

First note the sentence that reads ***"would materially lower the risk of BKH's natural gas exploration and production business."*** There is ***nothing*** in the COSG Program that makes natural gas exploration and production ***inherently*** less risky. If so, then how does the program "***materially lower the risk***" for BKH's E&P activities? There is only one way: by shifting this risk to ratepayers through the COSG Program.

Then note also that Fitch seems to think that the COSG Program is designed to acquire reserves to supply actual consumption requirements of BHC's utility customers. That is not the case. The reserves developed under the COSG Program will be sold to others at market prices. As planned, BHC's utility customers will not consume any of this gas. Their role is merely to provide guaranteed cost recovery with a promise to share in any excess economic profits the COSGCO venture might produce.

Fitch cannot really be faulted if it misunderstands the COSG Program. At the 2015 Analyst Day presentation CEO Emery said:

> And then finally, the cost of service gas program which I mentioned earlier. That's an opportunity we're really excited about. Having a portion of your gas portfolio come from a cost of service gas program provides an excellent long-term hedge for customers, certainly provides an investment opportunity for shareholders, ***and still leaves over half of the gas supply to be procured through regular means***. But it really gives them a good stability to their ongoing fuel costs as customers. [Emphasis supplied. Transcript of October 8, 2015 Analyst Day meeting, Page 4.]

Again, this reads like COSGCO is acquiring gas for the use of BHP's utility customers. While it alludes to the hedging aspect of the program, it still leaves the impression that this is gas that will be used by utility customers in the emphasized remark. Even with COSGCO, BHP will continue to procure ***all*** of its utility customer's gas supply through its "regular means." The 50 percent figure is an arbitrary limitation on the size of the COSGCO program in relation to the gas supply requirements of BHP's utility customers. In effect, BHC will be acquiring ***150 percent*** of its gas supply requirements under the COSG Program: 100 percent through "regular means" for its utilities and 50 percent through COSGCO to be sold to other natural gas purchasers at market prices. And precisely because it will be sold to other purchasers at market prices there is still full exposure to the typical and normal risks of E&P operations. The only risk mitigation to E&P exposure comes from shifting that risk to utility ratepayers.

It should be noted that when Mr. Iverson spoke at the Analyst Day meeting he described the program more correctly:

> Go to the next page here -- kind of give you an idea of how this works. We're not going to sell the physical gas to our affiliated utilities. So, it's going to be a financial structure. The resources will be owned and backed by physical assets, but the cost of service gas company that we're going to have will actually sell that gas into the market and provide a credit; or, if it's the other way round, provide an adder (ph) to the bill for the customers. And that'll flow through the -- our gas cost adjustments or electric cost adjustments. [Transcript of October 8, 2015 Analyst Day meeting, Page 14.]

The risk shifting aspect of COSGCO was made clear in a later exchange between Mr. Iverson ("BI" in the following excerpt) and an "Unidentified Participant" ("UP"):

> [UP] Just understand the ownership structure. So, the utilities don't own the reserves. The separate entity does. You guys (ph) are facing these delays (ph) on a financial contract that is delivered upon by the central entity that owns the reserves?
>
> [BI] That's correct. So, the ultimate owner of all the entities is the Black Hills Utility Holdings. It's the intermediate holding company that we have, that owns the utilities. It also own [*sic*] the entity that's doing the drilling, and owning the reserves.
>
> [UP] And what are the performance requirements for production, right? So, you guys go into agreement on (inaudible) approve the project. What is the performance on – drilling performance on (inaudible) performance on (inaudible)?
>
> [BI] There are no restrictions on the agreement that we -- already met. So, basically, what you get into is, are you -- you know, it gets more of a prudency-type (ph) issue. You know, you identify the property, and you go out and you conduct a drilling program that you've identified -- your five-year drilling program. If you comply with that program and go along, that's what gets put into the program. So, you could have -- if you have a bad well, that's part of the process. You may have really good wells. They get the full benefit of the well.
>
> [UP] So, that would all get loaded into the cost of the program.
>
> [BI] Right (ph).
>
> [UP] So, the -- like, a bad well gets sucked in and spread out over everything else.
>
> [BI] Right.
>
> [UP] So, you guys don't carry exposure to that.
>
> [BI] That's correct. So, what it gets to is, if you look at the returns of these kind of businesses, if you're taking that kind of risk, you're going to demand a higher than a utility return. So, what we've tried to do is look at this program and say, if you structure it this way, we're willing to accept that utility type of return on the program. [Pages 18-19 of Transcript of 2015 Analyst Day meeting.]

In other words, the risks "of these kind [sic] of businesses" are still present, but since they are shifted onto the ratepayers BHC is "willing to accept [a] utility type of return on the program."

Q. WHAT IS THE EXPERIENCE OF COMPANIES IN THE E&P INDUSTRY OF EARNING EXCESS RETURNS OF THE KIND NECESSARY TO DELIVER ON THE PROMISES BHC IS MAKING TO JUSTIFY THIS PROGRAM?

A. Some companies have earned excess returns over the past few years, and others have not. On balance, excess returns and losses balance out, which is what you should expect in a competitive industry environment. As noted above, the median ROE for the "E&P Group" as a whole was 11.3 percent. This is a close approximation to a risk adjusted cost of equity for this industry. To determine that I used the Capital Asset Pricing Model because the "beta" coefficients of the model provide a meaningful way to compare individual company risks and returns. In CAPM the cost of equity, "k" is:

$$k_i \quad = \quad r_f + \beta_i * r_p$$

where r_f is the risk-free rate, β_i is the individual stock's beta coefficient, r_p is the market risk premium, and k_i is the individual company's cost of equity. I developed estimates of the risk-free rate and the market risk premium from 180 day averages of returns on Standard & Poor's equity risk premium indexes. The "TR" index is an estimate of the expected total return, and the "ER" index is the expected return relative to the risk free rate. On June 6, 2016 the 180 day average of the "TR" index was 79.53, corresponding to an 8.0 percent (rounded from 7.953) expected total market return, and the 180 day average of the "ER" index was 53.57, corresponding to a 5.4 percent equity risk premium. The difference, 2.6 percent, is the implied risk free rate. Substituting the appropriate values into the CAPM model we get:

$$k_i \quad = \quad 2.6\% + \beta_i * 5.4\%$$

Individual results are shown below (from Exhibit____(BLC-1), Schedule 2)[4]:

[4] For the group as a whole, k = 2.6% + 1.64*5.4% = 11.5%.

CAPM Analysis of E&P Group ROE's

Company	ROE Median	Beta	"Alpha"
Apache Corp. (APA)	13.7%	1.64	2.3%
Anadarko Petro. (APC)	4.1%	1.57	-6.9%
Continental Res. (CLR)	21.7%	1.78	9.5%
ConocoPhillips (COP)	14.4%	1.35	4.6%
Denbury Resources (DNR)	10.8%	3.19	-9.1%
Marathon Oil (MRO)	6.6%	2.29	-8.4%
Noble Energy (NBL)	11.6%	1.42	1.4%
Oasis Petroleum (OAS)	13.9%	2.22	-0.7%
Pioneer Nat. Res. (PXD)	8.4%	1.41	-1.8%
Range Resources (RRC)	8.3%	1.01	0.3%
Whiting Petroleum (WLL)	11.3%	3.17	-8.4%
Group Median	11.3%	1.64	-0.7%

In CAPM “alpha” is a measure of whether a stock is producing excess returns or losses in relation to its market risk as measured by beta. Normally it is a measure of market returns. But it can also be used, as here, to evaluate whether a book return is above or below the required cost of equity in relation to a stock’s beta. When “alpha” is positive it indicates that the earned ROE is above the indicated required cost of equity; when “alpha” is negative it indicates that the earned ROE is below the indicated cost of equity. All of this is relevant because COSGCO is premised on being able to consistently produce excess returns, i.e. “alphas,” of more than 100 basis points above the required rate of return on equity. As shown in the table above, only 4 companies show “alphas” above 1.0 percent. Five companies show “alphas” that would fall below a 100 basis point deadband. Two companies show returns that would fall within such a deadband.

These results are not surprising to anyone who understands how competitive markets work. There will always be, over any given period of time, some winners and some losers. But on balance they will cancel out, leaving nominal expected excess returns at zero. In other words we are back to what I said earlier: over the long term you cannot "beat the market." This is just as true in product markets as it is financial markets. We are in fact witnessing this play out more or less in real time with the performance of the E&P Group in recent years. The attractive excess returns of 2006-2008 have brought a lot of new investment (along with new technology) into the industry seeking to capture some of these excess returns. Under pressure from this competition, excess returns have dissipated, and in 2015 no company in the E&P Group earned an excess return. There is simply no way that BHP can guarantee to the Commission that COSGCO will generate net excess returns over the long term, and without those net excess returns this program will not only not benefit utility ratepayers, it will actually harm them.

Q. THE BETA COEFFICIENTS FOR THE E&P GROUP SEEM QUITE HIGH. ARE THERE ANY INFERENCES WE CAN TAKE AWAY FROM THIS REGARDING THE COSG PROGRAM?

A. Yes, the betas ***are*** quite high, and there are inferences we can draw from that regarding the COSG Program. Beta coefficients above 1.0 imply above average market risk. For the E&P Group the betas range from 1.01 to 3.19, with a median of 1.64. These are quite high, but reflective of the high degree of risk in E&P activities. Investopedia describes the industry this way:

> Companies involved in the ***high-risk/high-reward*** area of exploration and production focus on finding, augmenting, producing and merchandising different types of oil and gas.[5]

The COSG Program is not making any of those risks go away. If COSGCO were set up as a stand-alone market traded company it would have a beta coefficient similar to the betas

[5] http://www.investopedia.com/terms/e/exploration-production-company.asp. Emphasis in quote supplied.

experienced by the E&P Group. Rather than make those risks go away, the COSG Program ***is shifting them to ratepayers***. I see two fundamental and fatal implications from this.

First, even if the reward to ratepayers were commensurate to the risks they will incur under the program, this would amount to a conscription of capital from ratepayers that is wholly inappropriate. Ratepayers do not expect a portion of what they pay for utility service to constitute an involuntary partnership in the risky E&P industry. If they have capital they want to invest in a “high-risk/high-reward” enterprise, they can do so by investing directly in the shares of a company in the E&P industry. It is simply inappropriate to force ratepayers into becoming risk-bearing partners with COSGCO.

But second, the return they get under the COSG Program is most assuredly ***not*** commensurate with the risk they are being ask to bear under the program. As I point out again below, almost all risks are being shifted to ratepayers. What kind of return should ratepayers expect for incurring this kind of risk? Based on the analysis above, they should expect a return of 8.9 percent above the risk free rate (11.5 percent, per Footnote #4, which is the risk adjusted cost of equity for E&P, less the risk free rate of 2.6%). What kind of return can they expect from COSGCO? Under COSG Program the ***best*** ratepayers can hope for is for COSGCO to produce an industry normal or average ROE over time of 11.5 percent. Economic and financial theory dictates that it is unreasonable to expect more, i.e., net excess returns, over time. Under the COSG Program COSGCO gets to keep 100 basis points of the difference between this 11.5 percent and the 9.86 percent used in the hedge credit/cost calculation (using the 2014 figure for example), so that ratepayers are left with a net return of 0.64 percent.

The only way to avoid this imbalance in risk and return would be to cap COSGCO’s ROE at the risk-free rate. Using the current risk-free rate of 2.6 percent (which was used in developing the 11.5 percent cost of equity for the E&P Group), if COSGCO can generate an average ROE of 11.5 percent over time, and is only allowed an ROE of 2.6 percent (using the current risk free rate), then ratepayers would get a return through the FPPA of 8.9 percent, equal to what they should expect given the level of risk they are expected to bear.

I am, however, not suggesting that the COSG Program can be remedied simply by setting the ROE at the risk-free rate. I think that the first point above, that the program amounts to a forced conscription of capital from ratepayers, turning them into *de facto* business partners with COSGCO in the high risk/high reward business of E&P activities, is a sufficient basis to reject the program.

Q. ARE YOU AWARE OF ANY CORROBORATING ANALYSIS OF THIS KIND OF NEGATIVE IMPACT ON RATE PAYERS FROM PROGRAMS LIKE THE COSG PROGRAM?

A. Yes. A study was recently published (February 2016) by Ken Costello, Principle Researcher, Energy and Environment, of the National Regulatory Research Institute (NRRI) titled *Vertical Arrangements for Natural Gas Procurement by Utilities: Rationales and Regulatory Considerations*, NRRI Report No. 16-04 (hereafter cited as the "Costello Report"). A copy is included here as Exhibit___(BLC-4). Costello considers a number of different kinds of vertical integration arrangements for acquiring natural gas reserves either "in the form of utility ownership of gas reserves (UOGR) or a joint venture with an affiliate exploration and production (E&P) company."[6] BKH's COSG Program is among the programs he looked at. Costello raises the same kinds of concerns that I have about the risk shifting in such programs. "One concern is the risk-reward effect on utility customers relative to the utility or its holding-company shareholders."[7] In describing "common features of UOGR" he includes "imbalanced allocation of risk to utility customers," concluding "most of the risks associated with the arrangement fall on utility customers, rather than the utility itself."[8] He later adds

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[6] Costello Report, "Executive Summary, iii.
[7] Costello Report, 4.
[8] Costello Report, 5, 6.

> From the perspective of utility customers, vertical integration seems to be a high-risk strategy. Under most proposals and actual plans, utility customers would be shouldering much more risk than utility or holding company shareholders.[9]
>
> After reviewing different vertical-arrangement plans, it seems clear that customer risk is excessive relative to utility or holding company risk. It is somewhat ironic that the major apparent reason for vertical arrangements is to reduce upside price risk to utility customers but, in the process, utilities are asking customers to take on new risks. Although an empirical question, it is conceivable that utility customers could face higher risk from a vertical arrangement that involves UOGR or a utility affiliate than from the absence of long-term hedging. A review of the vertical plans suggests that customers could very well bear higher risk from an action that purports to protect those same customers from risk.[10]

Everything Costello says is applicable to the COSG Program.

Q. ACCOMPANYING THE TESTIMONY OF MR. AARON CARR IS AN ECONOMIC EVALUTION MODEL OF THE COSG PROGRAM. DOES THIS MODEL ADDRESS ANY OF YOUR CONCERNS ABOUT THIS PROGRAM?

A. No, it does not. The model illustrates how COSG would evaluate prospective properties using a hypothetical scenario. I could go through and question certain input assumptions – discount rates, natural gas price forecasts, etc.[11] – but at the end of the day it would tell me nothing about the likelihood of any real project contributing to a return on equity that would generate the net excess return on equity necessary to result in a net overall benefit to utility ratepayers.

On the other hand, the model seems to confirm a main concern. Exhibit____(BLC-1), Schedule 3 compares the volatility of the ROE's for the hypothetical COSGCO investment analyzed in Revised Exhibit 7.2 to the volatility of ROE's of the E&P Group and the volatility of dividends for BKH. I use dividends rather than earnings for BKH because utilities are valued on the basis of the predictability and stability of the dividend payout as evidenced in their low stock betas. Dividend payments from the companies making up the E&P Group are negligible and so they are valued on the basis of earnings and have high stock betas. While

[9] Costello Report, 44.
[10] Costello Report, 44-45.
[11] I do discuss natural gas price forecasts later in my testimony.

complete data are shown in Schedule 3, the summary results are presented in the following table:

	Beta	CoV[4]
BKH[1]	0.67	6.17%
E&P Group[2]	1.64	62.9%
COSGCO[3]		87.4%

Notes:

[1] Data are BKH Dividends Per Share 2006-2015
[2] Data are Median E&P Group ROE's 2006-2015
[3] Data are projected "ROE Actual" from Revised Exhibit 7.2, 2016-2025, Page 5
[4] Coefficient of Variation

We cannot measure beta for COSGCO but we can measure and compare the coefficients of variation ("CoV") in the projected ROE's for the hypothetical asset to the E&P Group and to BKH's dividends. As we would expect from the variability of the E&P Group's ROE's, their CoV's are quite volatile, ranging from 51.0 percent to 515.7 percent, though mostly in a range between 51.0 percent and 64.1 percent. (CoV's for the individual companies in the E&P Group are in Schedule 1, Page 1 of 2.) The CoV for the COSGCO hypothetical example is 87.4 percent, a little higher than the typical E&P company, but not alarmingly so.

What is, or should be, alarming is how much higher the COSGCO CoV is than the BKH dividend stream. This corroborates what I've been saying – that the volatility of hedge costs and credits will be more like the volatility of ROE's in the E&P Group, and unlike the volatility of returns for a utility, amounting to a massive shift of risk from COSGCO to utility ratepayers.

Q. MR. VANCAS COMPARES THE PROPOSED COSG PROGRAM TO OTHER PROGRAMS THAT HAVE BEEN IMPLEMENTED IN OTHER JURISDICTIONS. ARE THOSE COMPARISONS HELPFUL?

A. Perhaps in an odd way I think some comparisons are helpful, but not in the way that was intended. For example, the Wexpro unit of Questar develops gas properties under a cost of service arrangement, but with two important distinctions: (1) Wexpro must acquire the reserve asset at its own risk, and then request cost of service treatment, and (2) the reserves so acquired and produced are for the direct benefit and use of Questar's utility customers. The latter point is important to describing an arrangement like this as a "physical" hedge. Despite BHP referring to COSGCO as a physical hedge arrangement, it is not, because it does not deliver gas to BHP to be used in direct service of ratepayer requirements. Perhaps it was a slip, but Mr. Iverson got it correct when he said at the Analyst Day event "We're not going to sell the physical gas to our affiliated utilities. So, it's going to be a financial structure." From a ratepayer perspective, COSGCO is a "financial" hedge, not a physical hedge.

Another example cited by Mr. Vancas was Northwest Natural Gas Company's joint development agreement with Encana Oil and Gas (USA) Inc., approved by the Oregon PUC in 2011. Again, this case involved an application to approve a specific development project, with the gas supplied from it to replace gas making up a portion of Northwest Natural Gas Company's gas supply portfolio. The arrangement does allow Northwest Natural Gas Company to opt between taking physical delivery and selling at market prices whereby the Company would have to purchase replacement gas at market prices. But this is a straight-forward physical hedge which does not involve acquiring additional reserves in the (vain) hopes of earning excess returns that can be used to offset the cost of BHP's actual gas supply portfolio.

Two of the projects or programs mentioned by Mr. Vancas have met an untimely demise. The Washington Gas Light plan to enter into an agreement with Energy Corporation of America to acquire 22 producing wells in Pennsylvania was rejected by the Virginia State

Corporation Commission in November 2015. Among the Commission's concerns was the fact that "WGL's customers would bear all of the Plan's risks and WGL (and its shareholders) would bear none of those risks."[12] While the deadband proposed here limits BHP's ratepayers from bearing ***all*** of COSGCO's risks, the risks borne by ratepayers are all out of proportion to the benefits received, as I will explain in looking at the next example. (I also demonstrated this above in showing that the only way to remedy the imbalanced risk/reward was to limit the ROE that COSGCO receives to a risk-free rate.)

The plan approved by the Florida Public Service Commission allowing Florida Power & Light to invest in a joint venture with PetroQuest Energy, Inc. to develop and operate new gas production wells in the Woodford Shale Gas region in Oklahoma was recently overturned by the Florida Supreme Court. Without opining on the legal merits of the case, I wish to call attention to the economic reasoning the Court used in reaching its decision, as it applies to aspects of the COSGCO proposal. In describing the case background, the Court said:

> FPL alleged that it was looking for opportunities to acquire natural gas at production costs (as an investor), rather than at market prices (as a purchaser), in order to help insulate customers from the volatility of the gas market. Specifically, FPL asserted that its ownership interest in the Woodford Project would operate as a long-term physical hedge against the market volatility of natural gas prices used to provide electric service to FPL's customers. FPL also asserted that the Woodford Project would benefit its customers by providing natural gas at a lower cost than market prices.[13]

With one exception this reads very much like what BHP is supposedly proposing with the COSG Program, the exception being that FPL was proposing to acquire physical gas for its customers, which the COSGCO arrangement would not do. Otherwise, the COSG Program is supposed to help insulate customers from the volatility of the gas market, and indirectly

[12] VA SCC CASE NO. PUE-2015-00055, ORDER ON APPLICATION, Page 8.
[13] Supreme Court of Florida, Nos. SC15-95, SC15-113, SC15-115, Citizens of the State of Florida, Appellant, vs. Art Graham, etc., et al, and No. SC15-274, Florida Industrial Power Users Group, Appellant, vs. Art Graham, etc., et al., Appellees, May 19, 2016, Page 3.

provide natural gas to BHP customers at a lower cost than market prices (through hedge credits – which must exceed hedge costs on a NPV basis to actually work).

The Court rejected the "hedging analogy." In discussing the use of a fuel clause to recover certain costs it stated:

> The [fuel clause] mechanism also permits utilities to recover actual costs of financial derivatives and physical hedges that help prevent price shocks from volatile fuel costs. However, regulated utilities through the fuel clause do not earn a return on money spent to purchase fuel. Likewise, while the costs of hedging contracts are pass-through costs, utilities through the fuel clause do not earn a return on the cost of hedging positions purchased.
>
> …
>
> Permitting advance recovery of FPL's investment in the Woodford Project's exploration and production of natural gas will not pay for the costs of actual fuel. It will provide recovery, instead, for investment, operation, and maintenance and operation assets that will provide an unknown quantity of fuel in the future. It is impossible to know what the costs of the natural gas will be until it is actually produced. There is more uncertainty from this investment rather than less. Therefore, it cannot be characterized as a physical hedge.[14]

This is a very cogent and telling ***economic*** analysis that applies, by and large, to the COSG Program. COSGCO will recover all operating expenses, a return on its investment, ***and*** a return of its investment (through depreciation). As a practical matter, and despite the deadband and a potential 100 basis point "loss" of return on equity, the COSG Program is asking for what amounts to a ***guaranteed equity return*** of 8.86 percent (to use the 2014 ROE the Company would propose, discussed further in Part IV of my testimony). Based on long term treasury rates, the "risk free" rate is currently less than 3 percent. What hubris makes BHC think that its shareholders should get a return of 8.86 percent on an investment that arguably has no more risk than a long term treasury bond? Government bonds are treated as risk free because of a negligent risk of default. Where is the risk of ratepayers defaulting on what passes through a fuel and purchased power adjustment clause?

The Florida Supreme Court is right to distinguish the recovery of various kinds of

[14] Op. cit., Pages 8-9.

operating costs and expenses through a fuel clause from the recovery of capital costs. The latter are returns for ***risk taking***. Since all operating risks are shifted onto ratepayers, asking them to pay any kind of return above a risk-free rate is inappropriate.

The Court went on to say:

> Additionally, under FPL's proposal for the Woodford Project, ratepayers (not FPL) bear the risk of natural gas price volatility and all of the production risks. If the production cost of extracting natural gas from the Woodford wells, including profit paid to FPL, on the capital investment, is less than the natural gas market price, the ratepayers will benefit. However, if the production costs of extracting natural gas from the Woodford wells is more than the natural gas market [price], the ratepayers do not benefit but will instead suffer a loss. The monies spent on the Woodford Project are not a mere pass-through, like other fuel expenses, because FPL will earn a return on its capital expenditures. Accordingly, the Woodford Project is a guaranteed capital investment for FPL; it is not a hedge to stabilize fuel costs.[15]

Again, another trenchant economic analysis, to which I would add for emphasis that FPL, or in this case COSGCO, would not just earn a return on its capital, but a full return of its capital. This guaranteed recovery of capital is no small matter. Every company in the E&P Group has at one time or another seen its book value per share decline from one year to the next, usually associated with negative ROE's. In 2015 Apache Corp., one of the E&P Group companies, saw its book value per share decline from $68.83 to $6.83. Only one company in the E&P Group did not see a decline in book value per share in 2015. Ultra Petroleum Corp., the company I dropped from the E&P Group because it just filed bankruptcy, saw its book value per share decline from $10.45 to a ***negative*** $3.78 in 2012. E&P is a risky undertaking! All that risk goes away when operating expenses and a return on and return of capital can be passed on automatically to ratepayers through a fuel and purchased power adjustment clause.

Q. A MAJOR PREMISE BEHIND THE PROPOSED COSG PROGRAM IS TO PROTECT RATEPAYERS FROM EXPOSURE TO NATURAL GAS PRICE VOLATILITY. WHAT HAS

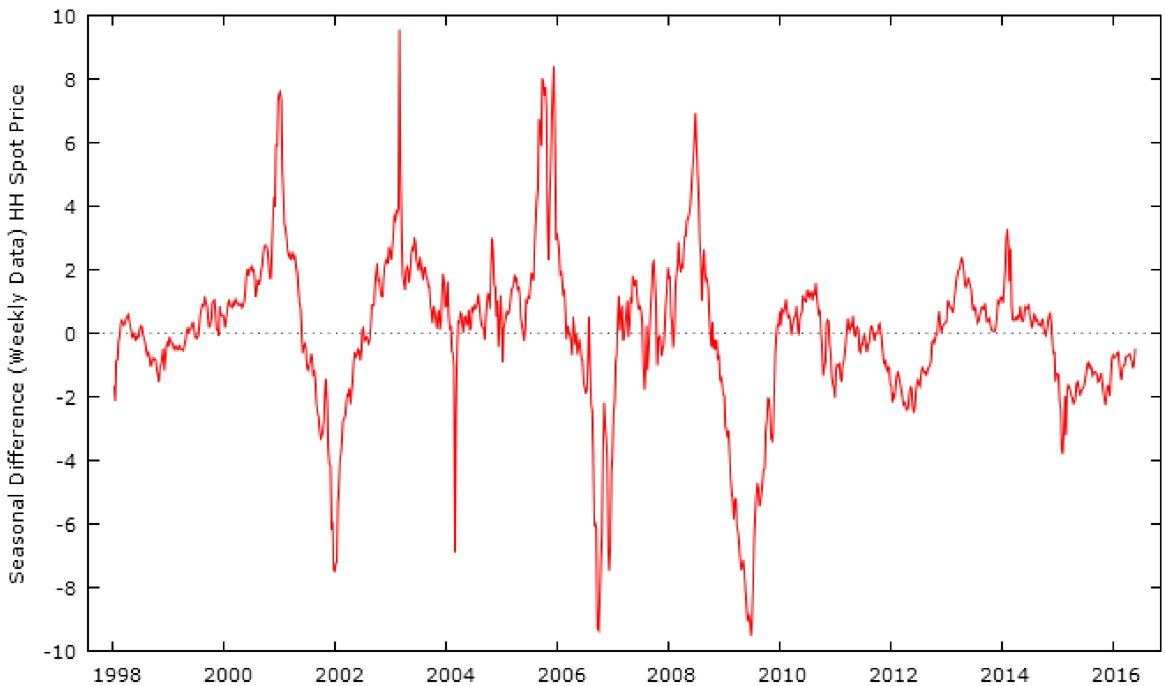
[15] Op cit., Page 10.

BEEN THE PATTERN OF NATURAL PRICE VOLATILITY, AND WHAT IMPLICATIONS DOES THIS HAVE FOR NATURAL GAS PRICE PROJECTIONS?

A. Mr. Loomis, BHUH Vice President for Energy Asset Optimization, discusses natural gas price volatility in his testimony. On Page 5, in Figure 1, he presents a chart of historical price volatility based on the Henry Hub spot price. He says:

> Even though the relative price levels are lower for the time being since the shale revolution, the chart shows there is still significant volatility and lack of stability in spot market prices. [Loomis Direct Testimony, Page 5, Lines 8-9.]

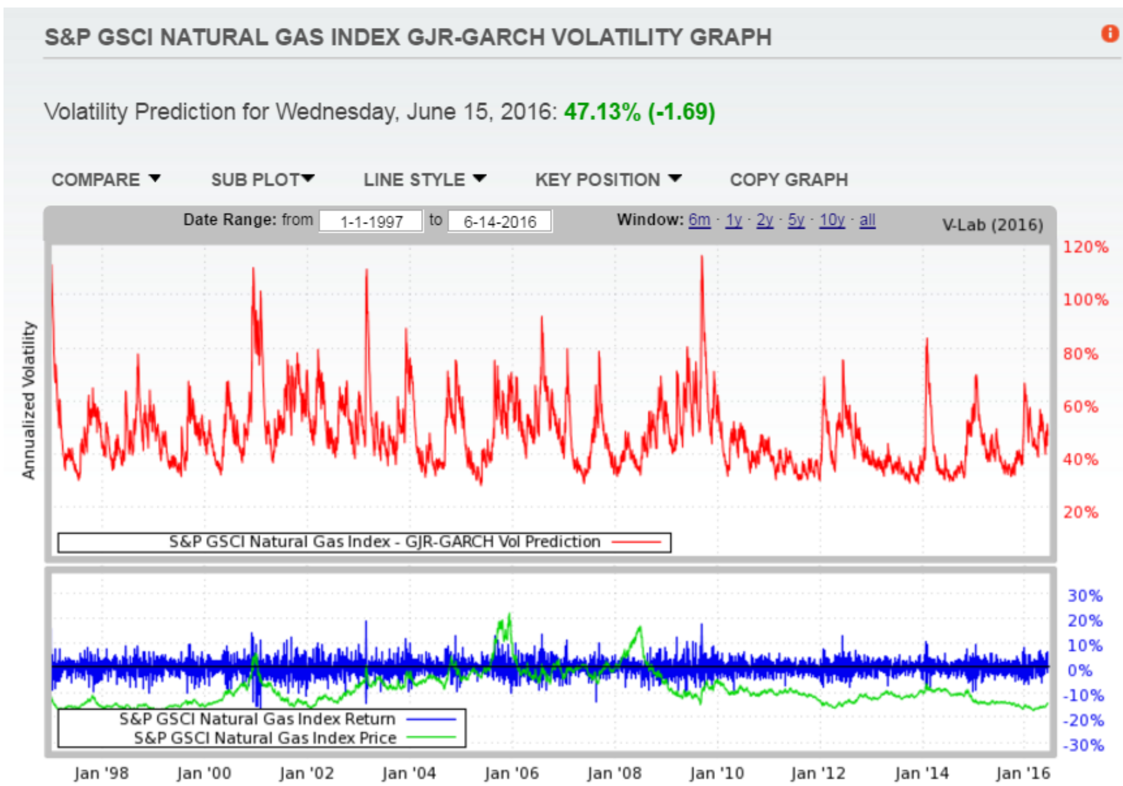
But he doesn't address the significant decline in volatility accompanying the shale revolution. To examine the price volatility of the Henry Hub spot price it is more informative to look at "seasonal differences" in price, as shown for weekly data in the following chart:



Depicted are Henry Hub weekly prices in any given week compared to the price that week in the preceding year. It doesn't take an advanced degree in statistics to see a remarkable decline in price volatility since 2010. Some might take this as the result of the shale revolution. Says Costello:

> Earlier in this century, we saw high price volatility resulting from moderate or even small changes in market conditions. With additional supply from shale gas, most analysts expect the market price to fluctuate less, especially to upward extremes. One implication from this development, running counter to vertical arrangements involving multi-year commitments, is fewer benefits to gas consumers from long-term hedging.[16]

A decline in volatility is also evident in the following chart, which depicts predicted volatility in the S&P GSCI Natural Gas Index. The peaks in this chart match closely to the peaks in my chart on the previous page, and show a moderation in peak predicted volatility since 2010.



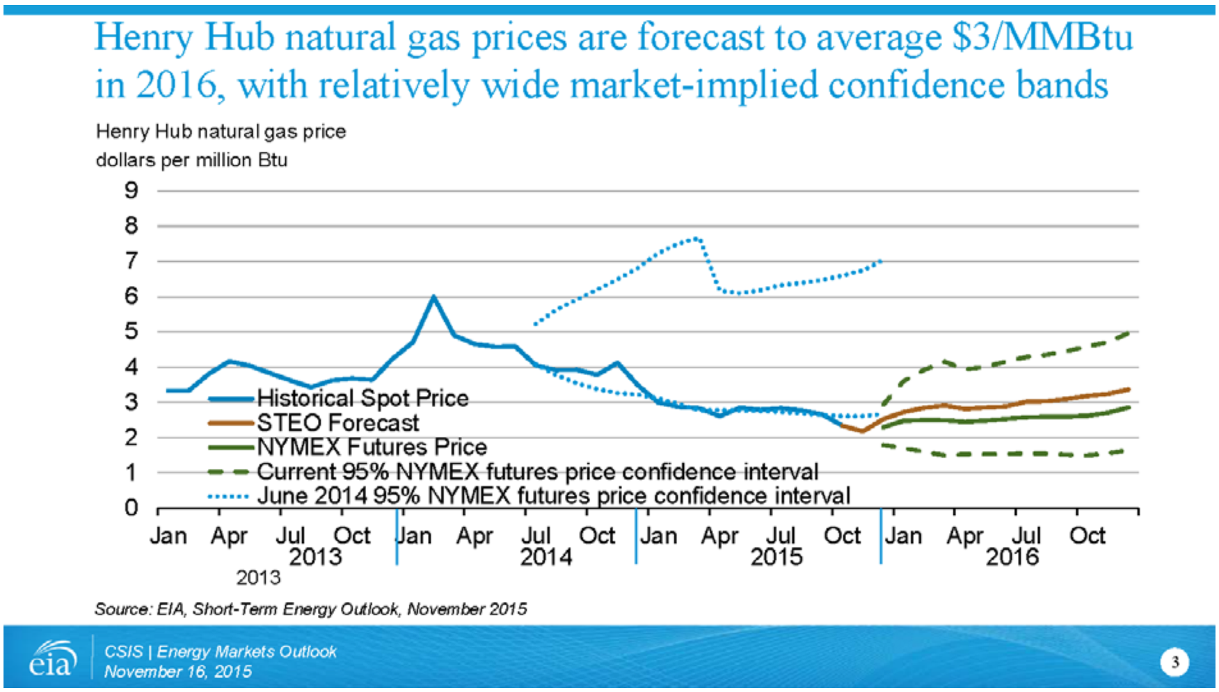
Volatility Summary Table

Closing Price:	$124.82	Return:	0.52%	1 Week Pred:	47.22%
Average Week Vol:	48.19%	Average Month Vol:	45.71%	1 Month Pred:	47.55%
Min Vol:	27.08%	Max Vol:	114.76%	6 Months Pred:	48.75%
Average Vol:	48.99%	Vol of Vol:	38.95%	1 Year Pred:	49.27%

But even with this decline in volatility, long run forecasts remain highly speculative. Long run changes in gas prices forecasts can change dramatically from one year to the next,

[16] Costello Report, Page 13.

and even over the short term the confidence intervals are quite large, as shown in the following chart:



For the July 2014 forecast the confidence interval for prices just a year and half out ranged from just under \$3 per mmBTU to \$7 per mmBTU. By late 2015 the actual price was below the bottom end of the confidence interval, and there was a new forecast for year end 2016 of under \$2 per mmBTU to \$5 per mmBTU. And this is just for short term forecasts. As the length of a forecast increases, the confidence limit of the forecast widens. If short term prices cannot be forecast with any significant degree of precision, why should we think that long term prices can be forecast with any significant degree of precision?

Q. **HAVE YOU EXAMINED THE LONG RANGE PRICE PROJECTIONS IN CONFIDENTIAL EXHIBIT 6.2?**

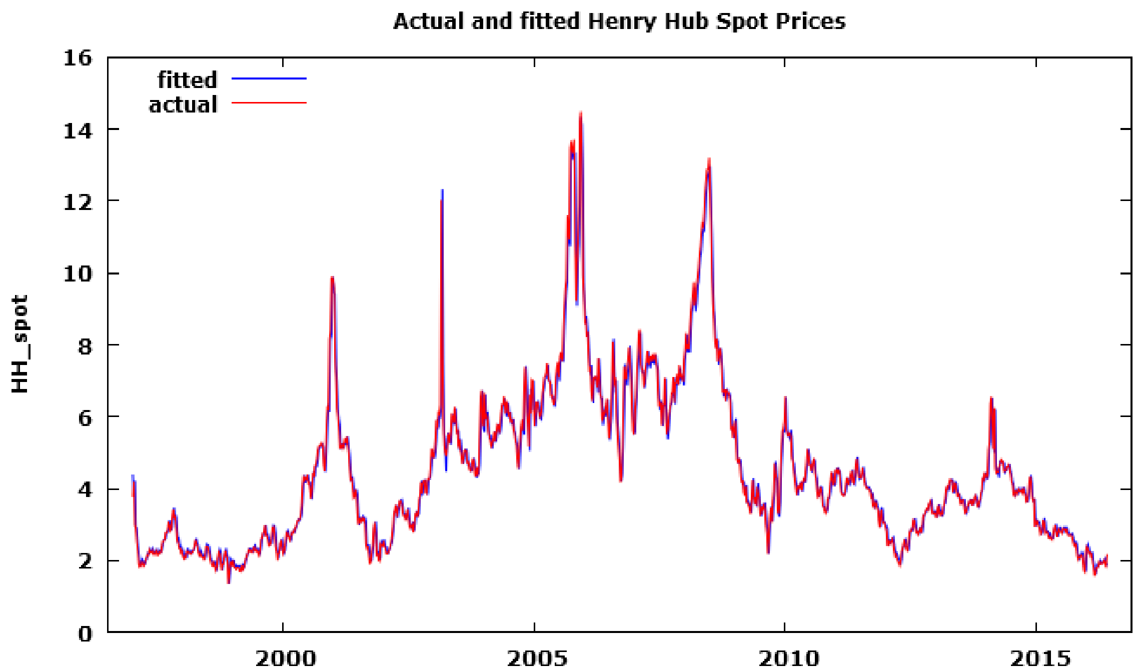
A. Yes, I have.

Q. **WITHOUT DISCUSSING ANY OF THE PROJECTION SPECIFICS, DO YOU HAVE ANY OBSERVATIONS ABOUT THEM?**

A. In my opinion the ranges reflected in the projections are uniformly too optimistic. I do not think they demonstrate the low level of confidence that must be associated with such long term projections.

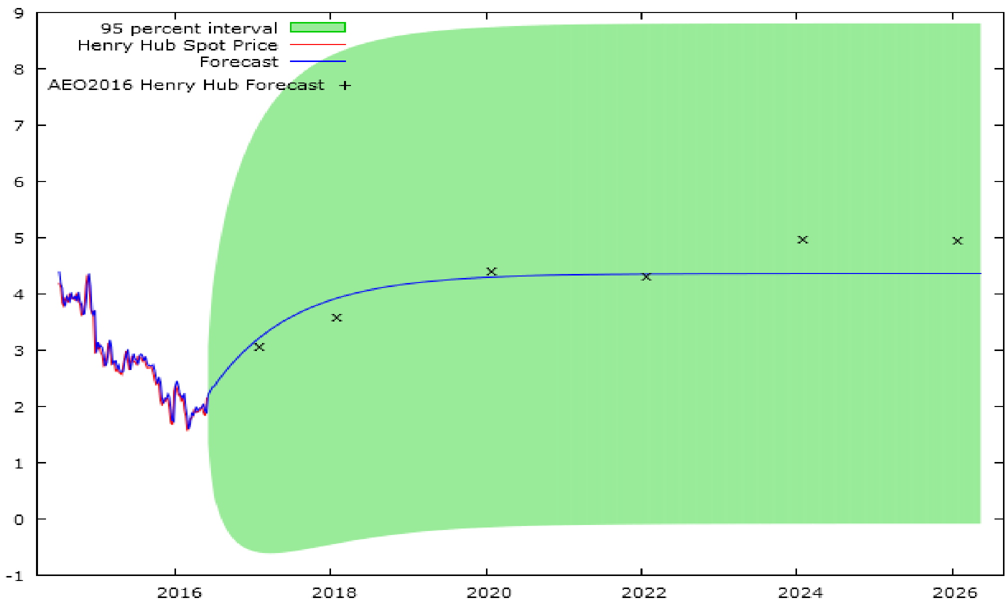
Q. WHY DO YOU SAY THAT?

A. I compared the price projections in Confidential Exhibit 6.2 to the output of an ARMA forecast based on Henry Hub spot prices. ARMA is an econometric time series methodology for modeling autoregressive moving averages.[17] An ARMA model resulted in a fit that more or less captures historical price movements perfectly, as shown in the following chart:



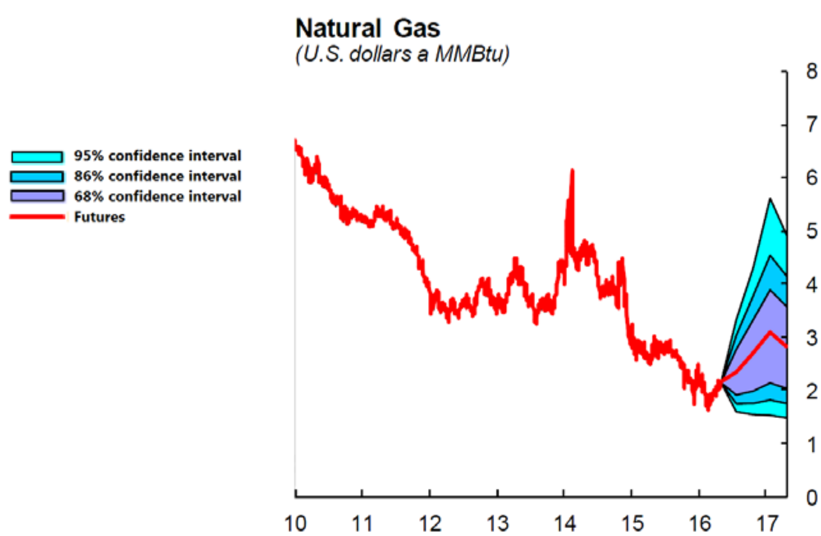
Using this model I ran a 10 year forecast, and compared it to the latest EIA projections, shown in the following chart:

[17] A “moving average” is what it sounds like. “Autoregressive” refers to a time series where future values are a weighted sum of past values.



By 2020 the 95 percent confidence interval encompasses a range of roughly \$0 to \$9 per mmBTU. In terms of range, the forecasts in Confidential Exhibit 6.2 are far more “confident” – i.e., are narrower – than what the historical volatility of prices would seem to justify.[18]

Further indication of the lack of confidence to be associated with long term gas price forecasts is indicated by the chart below:

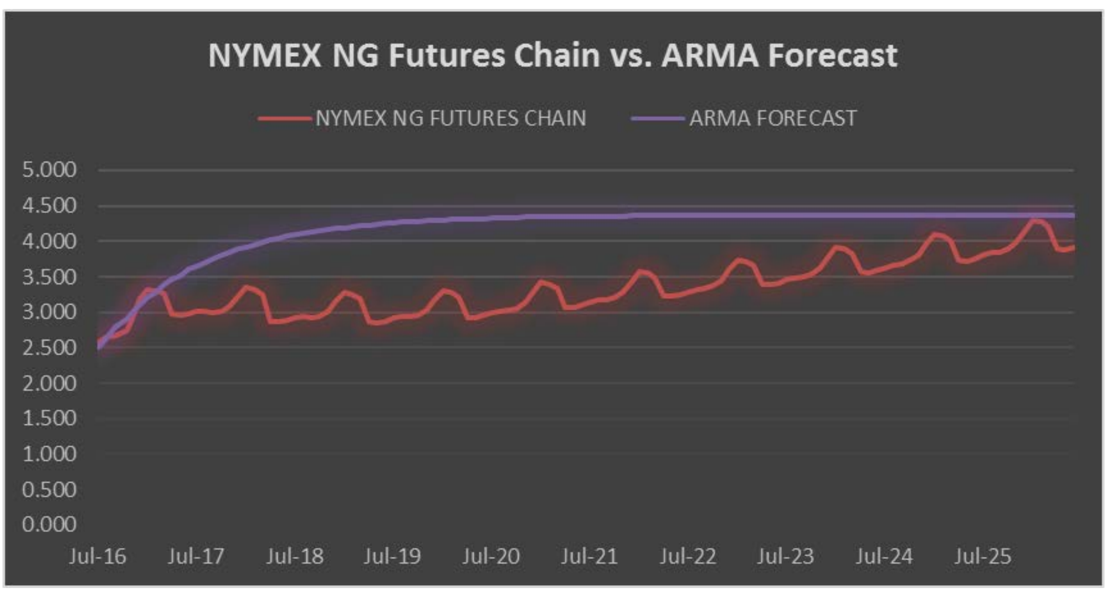


Source: IMF Commodity Price Outlooks & Risks, May 2016

[18] EIA’s long term projections for natural gas prices have also declined since Confidential Exhibit 6.2 was prepared.

It shows a recent forecast of U.S. natural gas prices by the International Monetary Fund with explicit confidence intervals charted. Just for one year forward the 95 percent confidence interval is approximately $1.50 per mmBTU to $5.00 per mmBTU. If prices were to be forecast over a longer horizon, this confidence interval would widen.

I want to emphasize that I am not arguing that ARMA is a better method of forecasting over the long term. The forecasts in Confidential Exhibit 6.2 were undoubtedly developed by people with a lot of experience in the industry. But as the short term forecasts by the U.S. Energy Information Administration show, "expert opinion" can change rapidly in this industry. ARMA and other methods of investigating "stochastic" properties of time series can certainly be "tweaked" to reflect industry specific expectations, and I haven't tried to do that. That might alter the path of a forecast, but is unlikely to reduce the uncertainty of it which is what I'm calling attention to here. Even so a "black box" ARMA forecast isn't out of line with the a current projection of natural gas prices implied by futures prices, as shown in the following chart:



In the final analysis, while the volatility of natural gas prices may have declined as a result of the shale revolution, they probably remain sufficiently volatile as to introduce a large range of possible outcomes for the future, i.e. a high degree of uncertainty and large confidence bands around any forecast.

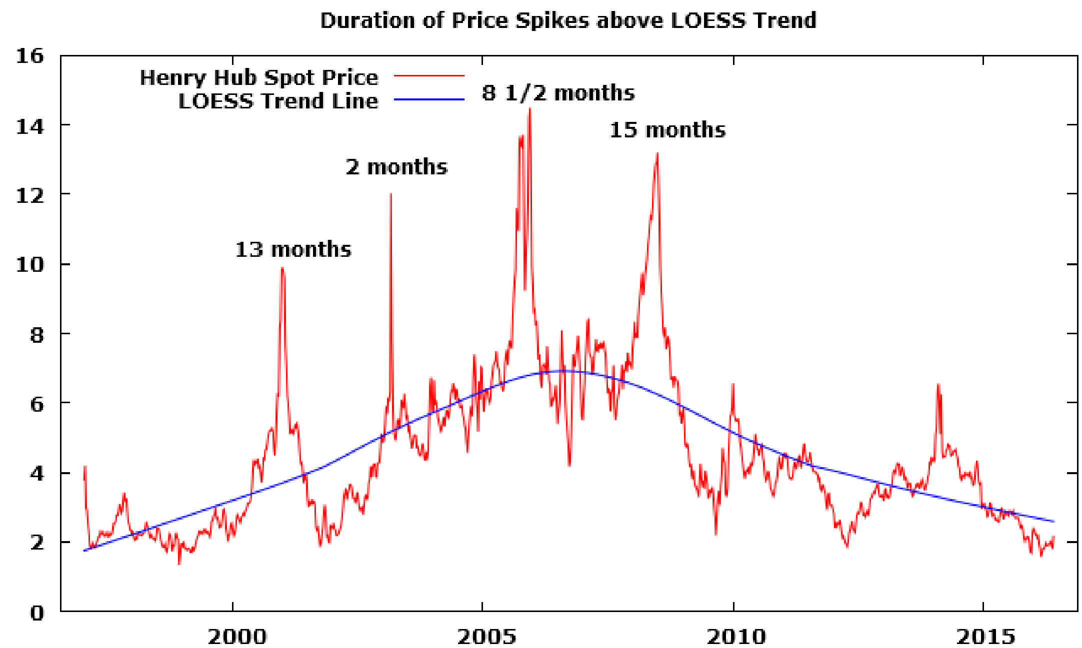
And so the elephant remains in the room. Whose responsibility is it to speculate on the long term level of natural gas prices, and put their money at risk in making investment decisions based upon their speculations? In a competitive market economy those kinds of investments are made by ***entrepreneurs*** and ***risk takers***. If they want to make investments based on the reliability of price projections like those in Confidential Exhibit 6.2, they are free to do so. After all, it is ***their*** money at risk. That is a far cry from what the COSG Program would do. Because of the way the program flows through all costs, subject to the hedge cost or credit calculation, BKH would no longer be exposed to the risk of whether their price forecasts were reasonable or not. In effect, they are asking the ***Commission*** to assume the responsibility whether or not the price forecasts are reasonable, and if so, agree to put ***ratepayer*** money at risk over whether or not the natural price gas forecasts materialize.

Q. IF PRODUCTION COSTS ARE MORE STABLE THAN VOLATILE MARKET PRICES, WOULDN'T THAT JUSTIFY THE COSG PROGRAM?

A. No, it wouldn't. Under the COSG Program, hedge costs and credits are still dependent on market prices. So in reality the program doesn't do anything to insulate ratepayers from natural gas price volatility. Instead of being exposed to volatility through the price of delivered gas, they are exposed to it through the volatility of hedge costs and credits.

The COSG Program is a solution in search of a problem. But it is not a solution to the problem of volatile market prices. "A utility can reduce volatility, for example, by layering fixed-price physical (forward contracts, storage) and fixed-price financial price hedges."[19] The greatest danger from market volatility are dramatic spikes in natural gas prices. But as shown in the chart below, these spikes are typically of short duration, and prices then return

[19] Costello Report, Page 16, Footnote 64.



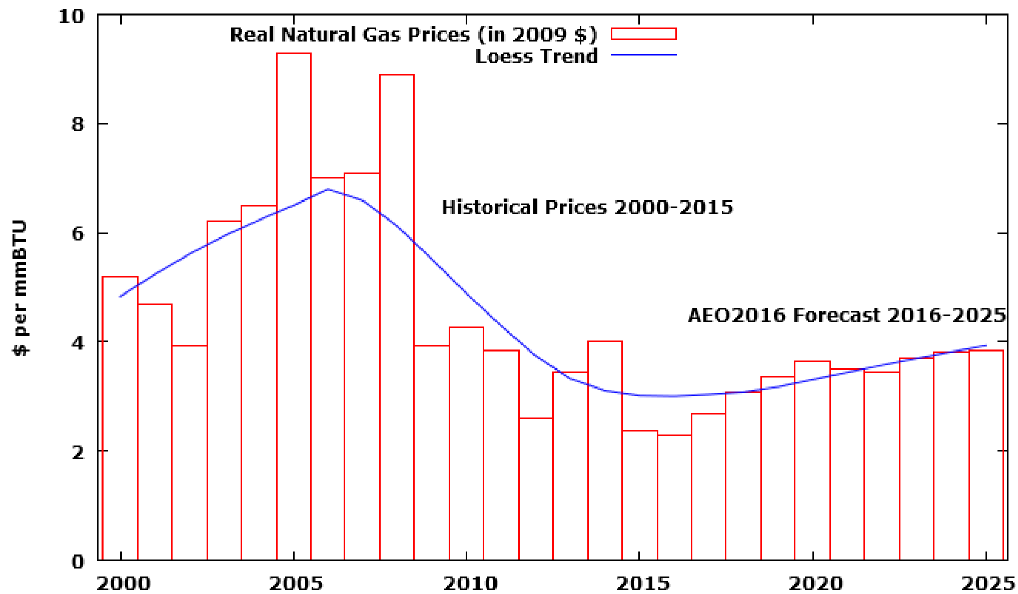
to a more normal level of volatility around longer term trends. These short term spikes are more than adequately managed by traditional short to mid-term hedging arrangements that BKH already utilizes (discussed and acknowledged by BHP Witness Julia M. Ryan, of Aether Advisors LLC, in her testimony and her Exhibit 5.1). A long term physical hedge, like the COSG Program seeks to copy – but be clear that it isn't a physical hedge at all, and will do nothing to reduce volatility to ratepayers – makes sense only if there is a high degree of confidence that prices will rise more rapidly than the rate of inflation. That has not happened historically, and there is no reason to expect it to happen over the next 10 to 20 years. According to the latest EIA forecast of natural gas prices:

> Annual average natural gas prices rise from their 2015 level, $2.62/ million British thermal units (MMBtu) at the benchmark Henry Hub, to roughly $5.00/million Btu in the mid-2020s and remain around that level through 2040. Technology improvements allow natural gas production to rise even as prices stabilize.[20]

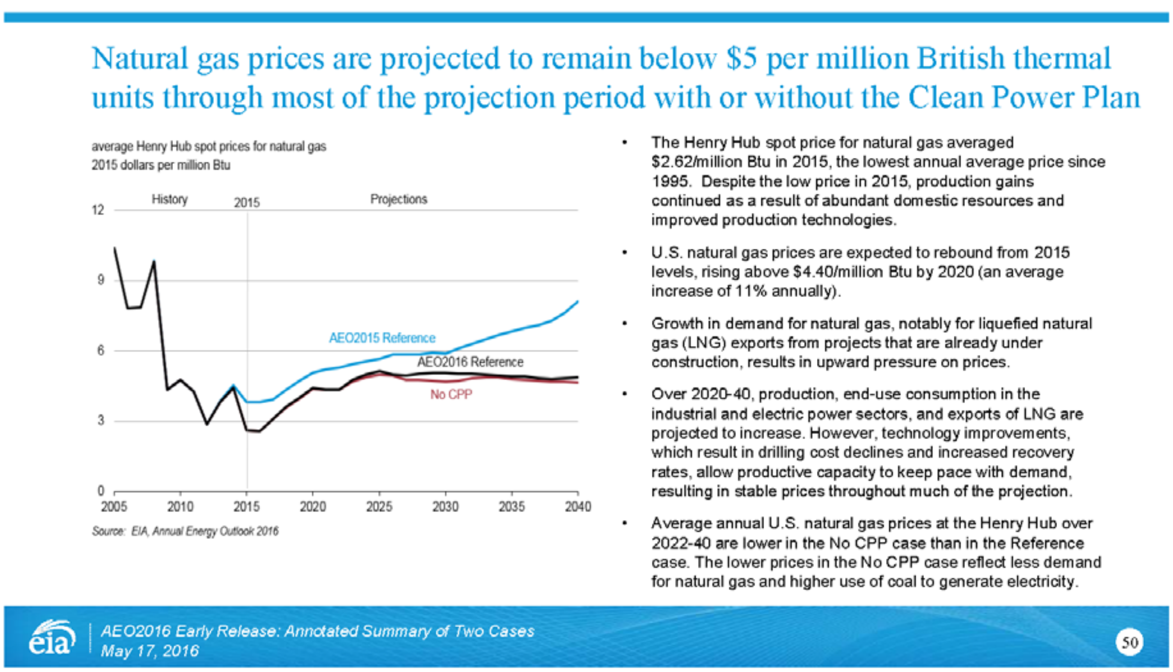
Relative to the median price ($4 mmBTU) experienced from 1997 to date, this does not suggest much if any long term increase in ***real*** natural gas prices. On the contrary, as the

[20] Annual Energy Outlook 2016 Early Release: Annotated Summary of Two Cases, May 17 2016, Page 7.

following chart shows, relative to the past decade and a half real gas prices to 2025 are expected to be lower (reflecting the impact of the shale revolution):



Under such conditions the need for a long term hedge (and again, this is not to acknowledge that the COSG Program is a long term hedge for ratepayers as it is not) is unnecessary. And as seen in the following graphic from the 2016 Annual Energy Outlook, the outlook for



natural gas prices has been dramatically reduced since the 2015 projection, a result that might impact what the Commission wants to take away from Confidential Exhibit 6.2. I've been seeing dire warnings of natural resource shortages and price increases since I was Deputy Director for Forecasting of the Arkansas Department of Energy nearly 40 years ago. The apocalypse keeps getting postponed, seemingly indefinitely. The same should happen to the COSG Program.

Q. PLEASE SUMMARIZE YOUR ANALYSIS OF THE COSG PROGRAM.

A. Despite presenting the program as a hedge that would benefit ratepayers by reducing the volatility of prices paid for natural gas, it seems clear to me that the real purpose of the program is to shift the risk of BHK's E&P operations to ratepayers. But whether that is the intent or not, that is what will happen. Nothing in the proposal reduces the inherent risk and volatility of returns to E&P operations. But unlike firms in the E&P Group, where the risk and volatility is inherent in their high betas and volatile ROE's, BHK will be shielded from such risks through the effective guarantee of full cost recovery – ***from ratepayers*** – of operating expenses, a return of investment (depreciation), and a ***guaranteed rate of return on equity*** of ***no less*** than 100 basis points below a utility based estimate of the cost of equity. Such a return is unjust and unreasonable in relation to the negligible risk to which BHK would now be exposed to in undertaking E&P projects. Since the risk of E&P operations has not been reduced, but merely shifted to ratepayers, and because the promise of consistently earning excess returns necessary to produce hedge credits that would offset hedge costs is empty, the COSG Program would not work to stabilize rates but would have precisely the opposite effect, exposing ratepayers to increased volatility in rates through significant volatility in hedge costs and credits.

IV. ANALYSIS OF METHODOLOGY FOR DETERMING AN ALLOWED ROE

Q. PLEASE DESCRIBE HOW THE ALLOWED RETURN ON EQUITY (ROE) WOULD BE SET UNDER THE COSG PROGRAM.

A. As proposed, the rate of return on equity for calculating hedge costs and credits under the program would be based on the average annual authorized ROE for gas and electric utilities for the corresponding calendar year as reported by *Regulatory Research Associates* ("RRA") annual survey of "Major Rate Case Decisions" published in its report *Regulatory Focus*. Using the 2014 edition, which was the latest edition at the time the COSG Proposal was filed, the allowed ROE would be 9.86%. There are two principal reasons why this approach should not be adopted.

Q. PLEASE EXPLAIN.

A. The first, and by far the most important, is what I call the "assumes facts not in evidence" problem. As the Commission well knows, every rate case presents a unique set of facts that go into determining what is a fair and reasonable rate of return on equity. What is reasonable in one case may not be reasonable in another. One utility may be more highly leveraged than another, a fact that directly affects an appropriate return on equity. Credit ratings often vary significantly from one utility to another, reflecting various differences including generation mix, operating market conditions, and other variations in "business risk" that may justify differences in ROE. Then there are the wide variations in regulatory principles (average versus year end rate base, relative use of trackers or automatic adjustment clauses, etc.) from one jurisdiction to another that make direct ROE comparisons difficult. While averages can sometimes be useful, they also have their limits, captured in the classic description of a "statistician" as someone who can stand with one foot in a bucket of boiling water, and the other foot in a bucket of freezing water, and say "On the average I feel fine."

To adopt an "industry average" essentially requires the Commission to abdicate its statutory responsibility to determine a fair and reasonable return on equity on the merits of each case it adjudicates. Note well that this does not mean that "averages" cannot be used in determining a reasonable ROE. It is done all the time, using a group of "comparable risk" companies. But that requires a prima facie showing of risk comparability to the applicant utility, something entirely lacking in the COSG Proposal. In fact, I would contend, based on the analysis presented in Section III, that the prima facie case here is one of clear non-comparability. How many of the utilities in the RRA *Regulatory Focus* report are ***guaranteed*** an ROE of 8.86 percent? Dare I say none? At the very least, I would argue that an ROE for COSGCO should be based upon BHK's cost of equity capital, not an industry average, and that would only be if COSGCO had the same risk profile as BHK. Since it clearly doesn't, even a return that would ordinarily be fair and reasonable to BHK would be inappropriate for COSGCO.

Q. WHAT IS THE SECOND PROBLEM?

A. The second problem is more technical in terms of trying to discern from the data in the RRA report just what the "average" really is. Even before we get to that, there is always the problem of whether or not to include or exclude certain "observations." In its narrative for the 2014 report it states:

> The average return on equity (ROE) authorized <u>electric</u> utilities was 9.92% in 2014, compared to 10.02% in 2013. There were 37 electric ROE determinations in 2014, versus 50 in 2013. We note that the data includes several surcharge/rider generation cases in Virginia that incorporate plant-specific ROE premiums. Virginia statues authorize the State Corporation Commission to approve ROE premiums up to 200 basis points for certain generation projects (see the Virginia Commission Profile). Excluding these surcharge/rider generation cases from the data, the average authorized electric ROE was 9.76% in 2014 compared to 9.8% in 2013.

Now the preceding relates only to electric utilities, not gas utilities. The COSG Program proposes using an average that combines both electric utilities and gas utilities (which is what is represented by the 9.86 percent return referenced in Witness Mackenzie's testimony).

But looking just at the results for electric utilities shows a major methodology issue (which would also be true for the gas utility ROE's): it ***excludes*** rate case decisions where the ROE is not published. This imparts a definite upward bias to the "average." Looking at the 2014 data for electric utilities, and excluding the Virginia ROE's and one other limited issue proceeding associated with the purchase of hydro facilities by Northwestern Corp., there were 32 electric cases with reported ROE's, and 9 rate cases without reported ROE's.

Taken together, 22 percent of the total were unreported. Moreover, 7 of those 9 unreported ROE's were in cases resolved by stipulations. It is highly likely that these unreported ROE's are ***lower*** than the average for the reported ROE's. After all, the most likely reason for not reporting an ROE in a settlement stipulation is because the utility does not want a low ROE to be reported. Exhibit___(BLC-1), Schedule 4, is a detailed analysis of the 2014 ROE data for electric utilities. For the 32 utilities reporting an ROE, the ***median*** ROE was 9.70 percent. While the median is often chosen to limit the influence of outliers, here it has the felicitous property of allowing us to develop a reasonable estimate including the 9 utilities whose ROE's were not reported. That is because the effect on the median is not affected by their individual values, but by their rank location. That is, when the 32 ROE's are sorted by rank, and we add in the 9 unreported ROE's in the bottom half of the sort (where they would most likely be found if reported), we can locate the new median simply by shifting down five spots (the median of 9). The effect of that is shown on Exhibit___(BLC-1), Schedule 4. The effect is to shift the median downward from 9.70 percent to 9.62 percent.

The primary reason for working through this exercise is to simply point out that picking a number out of the RRA *Regulatory Focus* report isn't as "objective" as it may appear. The reported "average" will always be biased upwards because of the exclusion of unreported ROE's that are in all likelihood below the industry average (or they would have likely been reported). And, as in the specifics of the Virginia ROE's, there are always questions about what to include or not include. Since the specifics are likely to vary from year to year, even if the first problem above did not exist, there is no way that a number could be mechanically plucked out of the RRA report each year and plugged into an automatic adjustment mechanism. The report wasn't designed for that use, and is unwieldy in such an application.

Q. DO YOU HAVE ANY OBSERVATIONS ON THE REQUESTED CAPITAL STRUCTURE OF 60 PERCENT EQUITY AND 40 PERCENT DEBT?

A. Yes, I do. If an appropriate ROE were used, capital structure wouldn't be an issue. Since the COSG Program guarantees recovery of all operating expenses, including depreciation, the appropriate ROE is a risk-free rate. Since that is likely to be lower than the embedded cost of debt, ratepayers would have no reason to object to a capital structure that is 100 percent equity and zero percent debt, as that would result in a lower weighted average cost than the proposed 60/40 capital structure! Do I expect to be taken seriously here? Not really. This is just a kind of *reductio ad absurdum* argument that shows the rabbit hole we are in danger of falling into here. What I do expect to be taken seriously is the ***inappropriateness*** of the wholesale shifting of risks of E&P operations from BKH to BHP's ratepayers that would transpire if this program were approved. Once that is recognized, details about ROE and capital structure become irrelevant.

V. RESPONSE TO SUPPLEMENTAL TESTIMONY

Q. HAVE YOU REVIEWED THE SUPPLEMENTAL TESTIMONY FILED BY THE APPLICANT ON JUNE 24, 2016?

A. Yes, I have. This testimony responds to concerns that have been raised in other states where testimony and even hearings have already occurred on the COSG Program. The Supplemental Testimony of Mr. Kyle White primarily responds to concerns about natural gas price forecasts, while Mr. Ivan Vancas' Supplemental Testimony responds to other aspects of the COSG Program and discusses potential modifications to it.

Q. DOES THIS SUPPLEMENTAL TESTIMONY ADEQUATELY ADDRESS ANY OF THE CONCERNS YOU HAVE RAISED?

A. No, it does not. To explain why not, I will begin with Mr. White's testimony. He states:

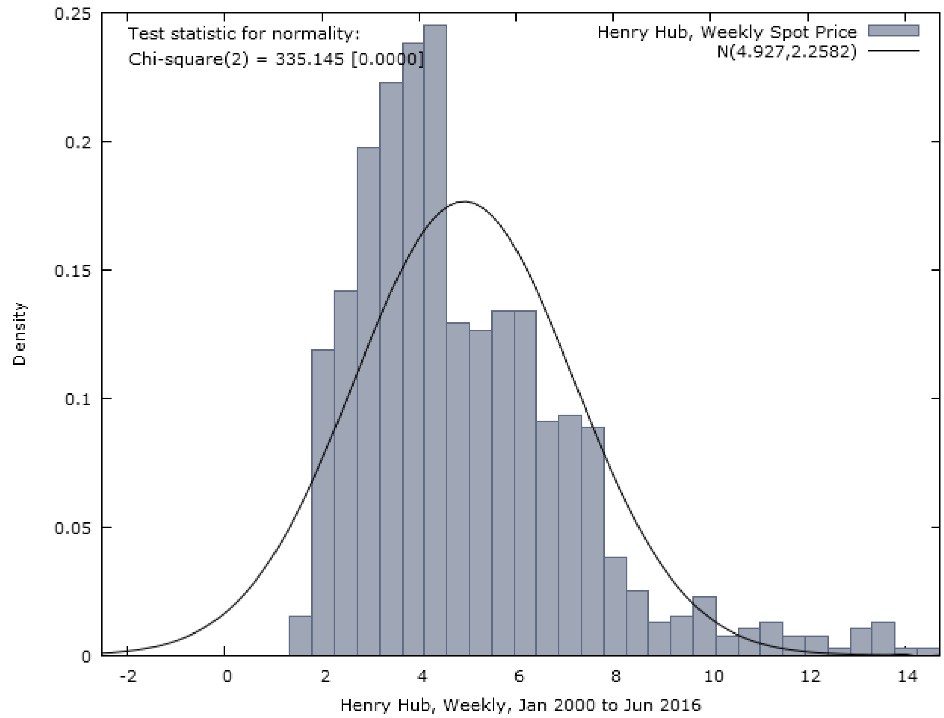
> The intervenors in other states do not fairly represent the value of forecasts or how they would be used in the COSG Program. The intervenors point out that forecasted prices do not match actual prices. This is an unremarkable observation. As the Commission is clearly aware, forecasts always vary to some extent from actual performance. That fact does not undermine the importance of using forecasts in utility decision-making. According to the intervenors' logic, one would never use long-term forecasts to make any resource decisions because actual performance will vary from forecasted performance. That view is clearly shortsighted and ignores the usefulness of forecasts. Long-term forecasts are routinely relied on throughout the utility industry to make long-term decisions. [White Supplemental Testimony, Page 3, lines 2-12.]

I would not dispute the contention here that "[l]ong-term forecasts are routinely relied on throughout the utility industry to make long-term decisions." What I've tried to draw attention to is how the COSG Program shifts the risk of making "long-term decisions" onto ratepayers without any corresponding "return" for bearing that risk. Consider how this differs from some other situations where long-term forecasts are made in the utility industry. Long-term forecasts are routinely considered in making decisions for electric utility capacity expansion. Predicting long-term <u>load growth</u> is not as fraught with uncertainty as is predicting long-term natural gas <u>prices</u>. Moreover, forecasting load growth is a forecast that typically concerns having the capability to meet service on demand requirements. We are not faced here with any question about having sufficient capacity (reserves) over the long term to meet natural gas service on demand requirements. The question is the price, not whether the gas will be there for purchase when customers need it. In the case of electric utility forecasts, the issue is often precisely whether the electricity will be available for purchase when customers need it. In this latter case there is a risk-sharing that takes place in which ratepayers agree (through Commission oversight and approval) to cost of service purchase of the output from a new facility in exchange for some degree of certainty that the service will be available on demand in the future.

That is not what this case is about, or how the natural gas price forecasts are being used. And this is driven home by the other main point of Mr. White's Supplemental Testimony. Mr. White has prepared an exhibit, Exhibit 11.1, to accompany his Supplemental Testimony. On the basis of this Exhibit 11.1, he concludes:

> In 83% of the months since January 2000, the average Henry Hub price was greater than $3.00 per dekatherm. In 90% of the months during that same 16-year period, the average Henry Hub price was greater than $2.75 per dekatherm. If instead we just consider average monthly prices at Henry Hub that were at least roughly double the current low spot market prices, we can see that 60% of the months are $4.00 per dekatherm or more. [White Supplemental Testimony, Page 5, lines 4-8.]

I've examined the frequency distribution of Henry Hub prices since the beginning of 2000 and these figures appear to be consistent with what I see in the frequency distribution. Since a picture is often helpful, here is the actual frequency distribution plotted graphically:



The frequency distribution shows a price above $2.95 about 78 percent of the time, close to the figures cited by Mr. White. He concludes that if COSGCO can "lock in" a price below a certain (confidential) figure that this would be a good deal for ratepayers. And I would not dispute that if COSGCO were applying for cost of service treatment of gas locked in at that price. That would indeed be more analogous to the electric utility that applies for and gets cost of service treatment for a proposed capacity expansion.

But that is not what is being proposed. Even if a certain cost could get "locked in," the benefit to ratepayers – the hedge credit or cost -- is still based on actual future market prices. Ratepayers are not going to get gas at that "locked in" price and are still exposed to risk from uncertain future market prices. The only way to properly balance the risks here would be for COSGCO to propose cost of service treatment at the "locked in" price of a specific reserve asset. If COSGCO thinks that it can acquire a reserve asset with a "locked in" cost of $X.yz per mmBTU, it should acquire the asset and ***then*** file a proposal for cost of service treatment at the "locked in" cost of $X.yz per mmBTU. The Commission can then look at the then current natural gas price forecasts and decide whether the transaction is in ratepayers' interests. If rejected, COSGCO is unharmed in that it can sell output at market prices and receive the corresponding profit or loss. This leaves the risk/return calculus where it belongs, with BKH and its investors.

Q. PLEASE EXPLAIN WHY THE MODIFICATIONS IN MR. VANCAS' TESTIMONY DO NOT RESOLVE YOUR CONCERNS WITH THE COSG PROGRAM.

A. Mr. Vancas says that the Company would not oppose the following changes (based on interaction with intervenors and staff in other states):

1) Lowering the limit on how much of the Company's weather-normalized annual demand would be "hedged" from 50 percent to 35 percent;
2) Increasing the deadband around ROE for calculating hedge costs and credits from 100 basis points to 200 basis points;
3) Reducing the equity in the proposed capital structure from 60 percent to 50 percent;
4) Modifying the components of the Long-Term Price Forecast for gas in the COSG Agreement to include futures prices for the first five years of the forecast;
5) Placing a cap on aggregate drilling costs for purposes of calculating hedge credits and costs during the first three years of the first drilling plan (along with an increase in the frequency of proposed drilling plans to three year plans rather than five year plans);
6) Increasing the 60-day review period to 180 days in the case of BHEP property, and 120 days in the case third-party properties, and 120 days for updated drilling plans, along with $250,000 funding for staff to use for outside support in reviewing applications.

While in the aggregate items 1-5 reduce ratepayer exposure to risk somewhat, individually and collectively they do not go far enough. As originally proposed, the COSG Program shifts almost all risks to ratepayers. Exposure to the risk of higher market prices is shifted to ratepayers through expected volatility in hedge costs and credits. COSGCO recovers all costs, while bearing none of the risks (other a loss of 100 basis points ROE). With items 1-

5, COSGCO would bear some additional token exposure to risk, but ratepayers would still be exposed to significant risks for which there are insufficient benefits.

While item 1 reduces the amount at risk, it doesn't do anything to change the imbalance between risk and return created by the COSG Program. Item 2 does not materially affect the imbalance between risk and return either. A bit more of COSGCO's return is at risk, but this is offset by the reduction in return to ratepayers. Items 2 and 3 together are band aids compared to the only thing that would actually resolve the risk and return imbalance: capping COSGCO's ROE at the risk free rate. Item 4 is literally only of marginal significance; some projects, at the margin, would be rejected. But the projects that continue to be accepted would still expose ratepayers to risks they should not be exposed to. Item 5 would reduce exposure to one particular kind of risk, but would still leave ratepayers exposed to significant volatility in hedge costs and credits.

Item 6 addresses concerns about the impact upon commission staff and state consumer advocates. Some of these concessions might be reasonable if the COSG Program was otherwise reasonable on the merits. But that is not the case. It is simply not appropriate to expose ratepayers to risks associated with E&P activity, which is what the COSG Program would continue to do, even after the limited concessions presented in the Company's Supplemental Testimony.

VI. CONCLUSIONS AND RECOMMENDATION

Q. WHAT ARE YOUR CONCLUSIONS AND RECOMMENDATION?

A. Several conclusions follow from my review of the COSG Program:

1) The COSG Program is based on the promise that COSGCO can create hedge credits that exceed hedge costs over time. But hedge credits are excess economic or financial returns. Economic theory says that the expected value of excess

economic or financial returns in competitive markets is zero. It is not rational or reasonable to expect net excess economic returns over time.

2) The COSG Program does not reduce utility ratepayer exposure to risk from natural gas price volatility. It merely transfers that risk from shareholders to ratepayers through volatility in hedge costs and hedge credits flowed through the fuel clause. The volatility of hedge costs and hedge credits can be expected to reflect the same kind of volatility seen in the earnings of publicly traded E&P companies.

3) The COSG Program will shift risks from BKH shareholders to utility ratepayers, creating an imbalance between risk and return. Using the 9.86 percent ROE from the 2014 RRA Regulatory Focus as an example, COSGCO would be ***guaranteed*** a rate of return on equity of no less than 8.86 percent even though all other risks have been shifted to ratepayers. None of the utilities used to develop the 8.86 percent ROE are guaranteed their ROE. Thus the proposed method of setting the ROE does not properly balance risk and return. The only way to remedy this imbalance would be to cap the COSGCO ROE at the risk-free rate of return. With the ROE set at the risk-free rate, issues regarding the use of RRA Regulatory Focus, as well as capital structure, are moot.

4) Forecasting natural gas prices is difficult enough, even over a one to two year horizon. Forecasting them over a decade or longer is speculative. Speculative investments – like E&P – are the province of entrepreneurs and risk-takers, not ratepayers. The COSG Program would shift responsibility for making risk decisions based on speculative forecasts of natural gas prices to the Commission, with the risk to be borne by ratepayers. If BHC thinks that it can “lock in” a gas reserve at an attractive rate relative to its expectations for long term gas price increases, it should undertake this investment at its own risk. Once made, it could petition the Commission to treat it as “cost of service gas” at a fixed cost per unit of gas to be recovered through the fuel clause. If rejected it can still sell the gas at market prices.

Either way, risks are borne by shareholders, not ratepayers, which is the way it should be.

5) Spikes in long term natural gas price volatility are short lived, and can be (and are) dealt with through traditional hedging mechanisms (forward contracts, futures, options). A long term ***physical*** hedge makes sense only if there is a good reason to expect a significant increase in ***real*** natural gas prices. Compared to gas prices over the past decade or longer (and not just the past year or two), EIA long term forecasts do not show any likely increase in ***real*** natural gas prices. (This probably reflects the net positive long term benefit of the shale revolution.) The value of a long term physical hedge seems negligible or even non-existent at the present time.

6) Modifications to the COSG Program suggested in the Company's Supplemental Testimony do not overcome these concerns or conclusions

I recommend that the COSG Program be rejected.

Q. DOES THAT CONCLUDE YOUR TESTIMONY?

A. Yes it does.

APPENDIX A

Publications of Basil L. Copeland, Jr.

"Double Leverage One More Time." ***Public Utilities Fortnightly***, August 18, 1977, 19-24.

"Alternative Cost of Capital Concepts In Regulation." ***Land Economics*** 54 (August 1978): 348-61.

"Estimates of the Cost of Equity for Public Utilities, 1971-1976." ***Journal of Business Research*** 7 No. 1 (1979): 9-17.

"The Cost of Equity Capital: A Model for Regulatory Review." In **Issues in Public Utility Regulation**, edited by Harry M. Trebing, 342-66. East Lansing: Michigan State University, Graduate School of Business Administration, Institute of Public Utilities, 1979.

"Capacity Planning, Reliability, and Outage Costs in Electricity Supply: Comments." In **Challenges for Public Utility Regulation in the 1980's**, edited by Harry M. Trebing, 511-516. East Lansing: Michigan State University, Graduate School of Business Administration, Institute of Public Utilities, 1981.

"Inflation, Interest Rates, and Equity Risk Premia." ***Financial Analysts Journal*** (May/June 1982): 32-43.

"Do Stock Prices Move Too Much to be Justified by Subsequent Changes in Dividends? Comment." ***American Economic Review*** 73 No. 1 (1983): 234-35.

"Inflation, Monetary Policy, and the Equity Risk Premium." In **Regulatory Reform: The State of the Regulatory Art, Emerging Concepts and Procedures** edited by J. Rhoads Foster, 183-201. Washington: Institute for Study of Regulation, 1984.

"Ratemaking Treatment of Excess Capacity: Reconciling Regulation with Consumer Sovereignty." In **Changing Patterns in Regulation, Markets, and Technology: The Effect on Public Utility Pricing** edited by Patrick C. Mann and Harry M. Trebing, 407-40. East Lansing: Michigan State University, Graduate School of Business Administration, Institute of Public Utilities, 1984.

"Bailing Out Public Utilities with Troubled Nuclear Power Plants: Who wins, Who Loses?" In **The Impact of Deregulation and Market Forces on Public Utilities: The Future Role of Regulation** edited by Patrick C. Mann and Harry M. Trebing, 371-91. East Lansing: Michigan State University, Graduate School of Business Administration, Institute of Public Utilities, 1985.

"Price Theory and Telecommunications Regulation: A Dissenting View," with A. Severn. ***Yale Journal on Regulation*** 3 No. 1 (Fall 1985): 53-85.

"Capital Gains Taxes After Tax Reform," with Alan K. Severn. ***Journal of Portfolio Management*** 13 No. 3 (Spring 1987): 69-75.

"Escape from the Black Hole of FERC: A Proposal to Restore ***Pike*** Prudence Review," with Robert E. Johnston. ***The Electricity Journal*** 2 No. 4 (May 1989): 12-25.

"Telecommunications Regulation - The Continuing Dilemma: Commentary." In **Public Utility Regulation, The Economic and Social Control of Industry**, edited by Kenneth Nowotny, David B. Smith, and Harry M. Trebing, 131-36. Boston: Kluwer Academic Publishers, 1989.

"Procedural vs. Substantive Economic Due Process for Public Utilities," with Walter Nixon. ***Energy Law Journal*** 12 No. 1 (Spring 1991): 81-110.