AFFIDAVIT

STATE OF PENNSYLVANIA)
) ss.
COUNTY OF Chester)

I, Stephen E. Bennett, being first duly sworn on oath, do hereby depose and state:

1. I have been retained by Constellation NewEnergy-Gas Division, LLC ("CNEG") to review the Application for Approval of Participation in Proposed Cost of Service Gas Program and Related Transactions and for Allowance of Cost Recover and Conditional Request for Waivers ("Application") filed by Black Hills Energy/Nebraska Gas Utility Company LLC ("Company") on September 30, 2015, and my business address is 164 Chaps Lane, West Chester, PA 19352.

2. I have prepared the written direct testimony to which this affidavit is attached and caused my written testimony to be filed with the Nebraska Public Service Commission on February 16, 2016.

3. I hereby affirm that my written direct testimony is true and correct to the best of my knowledge and belief as of the date of this affidavit.

Dated this 16th day of February 2016.

/s/
Stephen E. Bennett

Subscribed and sworn to before me this 16 day of February 2016.

/s/ Jean
Notary Public, State of Pennsylvania
My commission expires: [Feb 4.2019]

COMMONWEALTH OF PENNSYLVANIA
NOTARIAL SEAL
JEAN P. JOHNSON, Notary Public
Lower Oxford Township, Chester County
My Commission Expires February 4, 2019

BEFORE THE PUBLIC SERVICE COMMISSION OF NEBRASKA

IN THE MATTER OF THE APPLICATION	)	
OF BLACK HILLS NEBRASKA GAS	)	
UTILITY COMPANY, LLC D/B/A BLACK	)	Application No. NG-0086
HILLS ENERGY FOR APPROVAL ITS	)	
GAS HEDGE AGREEMENT WITH BLACK	)	
HILLS UTILITY HOLDINGS, INC.	)	

DIRECT TESTIMONY

OF

STEPHEN BENNETT

ON BEHALF OF

CONSTELLATION NEWENERGY – GAS DIVISION, LLC

FEBRUARY 16, 2016

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EXHIBIT SB-1 - BHC ANALYST DAY PRESENTATION

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EXHIBIT SB-3 - BARBARA SUMMERS DIRECT TESTIMONY

EXHIBIT SB-4 - VIRGINIA SCC ORDER

EXHIBIT SB-5 – RECREATED ECONOMIC MODEL NPV ANALYSIS (CONFIDENTIAL)

I. INTRODUCTION

Q1. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A1. My name is Stephen E. Bennett. My business address is 402 Valley Drive, Lincoln University, PA 19352.

Q2. ON WHOSE BEHALF DO YOU APPEAR TODAY?

A2. I have been retained by Constellation NewEnergy-Gas Division, LLC ("CNEG") to review the Application seeking Approval of its Cost of Service Gas Hedge Agreement with Black Hills Utility Holdings, Inc. ("Application") filed by Black Hills/Nebraska Gas Utility Company, LLC, d/b/a Black Hills Energy ("Company") on September 30, 2015. CNEG retained my services to review the Application from the perspective of a competitive natural gas supplier.

Q3. PLEASE PROVIDE YOUR EDUCATIONAL TRAINING AND WORK EXPERIENCE IN THE COMPETITIVE ENERGY SUPPLY INDUSTRY.

A3. I earned a Bachelor of Science in Civil Engineering from the University of Maryland-College Park in 1996. I have almost 15 years of experience in the competitive wholesale and retail energy industry with a focus on retail market policy and structure, compliance, and RTO/ISO market rules and settlements. Currently, I am a consultant on wholesale and retail energy matters. Prior to that I served as Senior Manager, Markets & Regulatory Policy for PPL/Talen Energy. Prior to that I served as the Senior Manager, State Government Affairs – East for Exelon Generation Company, LLC where I was responsible for directing and implementing Constellation's regulatory policies for the competitive retail market in Ohio, Illinois, Pennsylvania, and Michigan.

Q4. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THIS COMMISSION?

A4. No. I filed written testimony in an identical Black Hills Corporation ("BHC") cost-of-service gas proceeding before the Iowa Utilities Board. In addition, I testified in multiple cases before the Public Utility Commission of Ohio in which regulated utilities sought cost-of-service rate-making for unregulated assets that are currently owned by unregulated subsidiaries of those same utilities.

II. <u>PURPOSE OF TESTIMONY</u>

Q5. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A5. The purpose of my testimony is to illustrate the concerns and potential issues raised by the Application as it seeks Commission approval for the Company, through an unregulated affiliate, to either acquire new or transition existing unregulated natural gas reserve assets to a cost-of-service ratemaking structure. The Application, as proposed, transitions the risk of natural gas exploration and production ("E&P") from BHC shareholders to the Company's captive customer base. The appropriate allocation of risk and the elimination of subsidies for utility commodity supply are fundamental to an effective and sustainable gas choice market. My testimony discusses the significant risk inherent to the Cost of Service Gas ("COSG") Program and how it may impact Nebraska customers.

Q6. ARE THERE ANY EXHIBITS THAT ACCOMPANY YOUR TESTIMONY?

A6. Yes. BHC held an analyst day on October 8, 2015 that included discussion of the COSG Program. I attach the publicly available presentation distributed by BHC for the analyst day as Bennett Exhibit SB-1 and the transcript from the presentation as Bennett Exhibit SB-2.

Company witness Vancas references a cost-of-service gas program implemented in Oregon by Northwest Natural Gas ("Northwest"). He also references a proposal in Virginia by Washington Gas Light ("WGL") that was ultimately rejected by the Virginia State Corporation Commission ("SCC"). I am attaching direct testimony from Oregon Public Utility Commission ("OPUC") docket UM 1717: NORTHWEST NATURAL GAS POST-CARRY WELLS APPLICATION filed by Northwest witness Barbara Summers as Bennett Exhibit SB-3. I am also attaching a

Virginia SCC Order denying the WGL application in Case PUE-2015-00055: APPLICATION OF WASHINGTON GAS LIGHT COMPANY FOR APPROVAL OF A NATURAL GAS SUPPLY INVESTMENT PLAN PURSUANT TO § 56-609 OF THE CODE OF VIRGINIA as Bennett Exhibit SB-4.

Company witness Carr developed a hypothetical economic evaluation model for the COSG Program and filed it as Carr Exhibit AC-2. I recreated the portion of the model that focuses on the Net Present Value ("NPV") analysis of the COSG Program. I am attaching it as Bennett Exhibit SB-5 (CONFIDENTIAL).

III. OVERVIEW OF THE COST OF SERVICE GAS PROGRAM

Q7. CAN YOU PLEASE DESCRIBE THE BLACK HILLS CORPORATION CORPORATE STRUCTURE AS IT IS RELATES TO THE COSG PROGRAM?

A7. BHC is a New York Stock Exchange listed corporation and the parent company of a number of energy-related subsidiaries that deal in electricity generation, transmission, and distribution, natural gas distribution and E&P, coal mining, and other services. The subsidiaries include Black Hills Non-Regulated Holdings, LLC, Black Hills Utility Holdings, Inc. ("BHUH"), Black Hills Power, Inc., Cheyenne Light, Fuel, & Power Company, and Black Hills Service Company, LLC. In turn, BHUH acts as parent to the Company and the other regulated utilities that were acquired from Aquila, Inc. in 2008. In addition, Black Hills Non-Regulated Holdings acts as the parent company to Black Hills Exploration & Production, Inc. ("BHEP").

Q8. CAN YOU PLEASE STATE YOUR UNDERSTANDING OF THE COSG PROGRAM AS PROPOSED BY THE COMPANY?

A8. At its core, the COSG Program is a mechanism by which the Company, through a new subsidiary, can acquire natural gas reserves with both a guarantee that the costs associated with developing the reserves will be recovered and a guarantee that a return on the equity of the asset will be realized. Under the COSG Program, BHC will create an unregulated subsidiary called the Cost of Service Gas Company ("COSGCO") to purchase natural gas reserves on behalf of its regulated natural gas distribution utilities in Nebraska and several other states. Although COSGCO will be an unregulated subsidiary, it will be placed under BHUH. Once established, COSGCO will acquire natural gas reserves from either a third party or from its BHEP affiliate; with a target volume of 50% of the Company's forecasted annual firm gas demand each year. The natural gas reserves that COSGCO purchases will not be for use by customers in Nebraska or in any of the states participating in the COSG Program. Rather, COSGCO will sell the natural gas on the open market. However, unlike the majority of natural gas suppliers selling on the open market, COSGCO would be guaranteed to recover its costs and receive a return on its reserve assets, regardless of the market price of gas.

The COSG Program affords these guarantees to COSGCO because it requires customers to pay COSGCO, through the Company, in the event that the open market sales revenues are not sufficient to both cover COSGCO's costs and provide the money necessary to pay out the guaranteed return. The COSG Program provides the guaranteed return on the reserve assets through an allowed Return on Equity ("ROE"). The allowed ROE is basically a guaranteed profit or a profit requirement for COSGCO.

The mechanism by which the COSG Program provides guaranteed cost recovery and profit to COSGCO hinges on the costs incurred to develop and maintain the reserve asset and to bring the natural gas to market as they compare to the revenues realized through the sale of the gas. First, COSGCO nets the sales revenue against the incurred costs. If the revenues from these sales do not cover COSGCO's costs and the allowed ROE, then customers in Nebraska and the other participating states will be required to make up the difference by paying a "Hedge Cost." If the revenues exceed the cost plus allowed ROE, customers will receive a "Hedge Credit" for the excess amount. The allowed ROE includes a “deadband” of 1% below and 1% above the allowed ROE. If the profit earned by COSGCO falls within the deadband, then customers neither make the company whole for the profit shortfall nor do they receive a credit for the excess profit. For example, if the allowed ROE is 10% then customers would pay Hedge Costs when the COSGCO earnings fell below 9% but would receive Hedge Credits when the COSGCO earnings exceeded 11%. In all cases, however, COSGCO is guaranteed to receive the allowed ROE within the 2% deadband range, which is represented by the 9% - 11% range in the example above. As currently proposed, the COSG Program would allow COSGCO to acquire an unregulated reserve asset, including one that is owned by BHEP, and turn it into a quasi-regulated asset that is guaranteed to return a profit by essentially transferring the risk of profitably developing the asset to its customers.

Q9. CAN YOU PLEASE EXPLAIN YOUR UNDERSTANDING OF WHAT THE COMPANY IS REQUESTING IN ITS APPLICATION?

A9. The Company is asking the Commission to rule that the COSG Program is prudent as it is proposed in the Application and that the Company can recover the costs and guaranteed profit associated with the program. In its request for a determination of prudency, the Company is asking the Commission to approve four specific aspects of the COSG Program. In simple terms, the Company is seeking Commission approval on the COSG Agreement that will govern the terms and structure of the COSG Program, the revised tariff sheets that will authorize assessment of Hedge Costs and Hedge Credits to customers, the 50% volumetric target of the program, and the waiver of certain affiliate rules and ring-fencing requirements that were put in place to preserve the separation of BHC’s regulated and unregulated businesses. If the COSG Program is approved, the Commission would then be required to review each drilling plan proposed by the Company. The review would be conducted under an aggressive timeline and with data provided largely by the Company and its hired monitors. The Company is asking the Commission to authorize the COSG Program without knowing which reserve assets will be selected and without receiving an indicative cost/benefit model from the Company. Even with an indicative model, the cost/benefit analysis of the COSG Program and any subsequent drilling plans would be largely based on projections and forecasts, each of which would decline in confidence level as the Company tries to predict price and production over the twenty-year life of the asset. Considering that the COSG Program only provides a guaranteed benefit to the Company and not to the customers of Nebraska, the Company is asking the Commission to authorize a program that brings with it significant amount of risk for Nebraska ratepayers and that relies on a lot of "trust us" from the Company.

IV. RETURN ON EQUITY

Q10. IN ASKING THE COMMISSION TO RULE ON THE PRUDENCY OF THE COSG PROGRAM, IS THE COMPANY REQUESTING THAT THE COMMISSION SET THE ALLOWED ROE?

A10. No. While the COSG Program includes a guaranteed profit to COSGCO through the allowed ROE, the Company is not asking the Nebraska Public Service Commission to set the ROE as part of the program. Rather, the Company proposes that the allowed ROE be set as the average of the annual ROE for all gas and electric utility rate cases nationally for the calendar year, as reported by Regulatory Research Associates ("RRA"). Put simply, even though Nebraska customers are likely to be called upon to pay COSGCO some or all of the allowed ROE, that ROE will not be set by the Commission. Instead, it will be set at a level that represents the average ROEs for natural gas and electric rate cases of which the majority were determined by Commissioners in states other than Nebraska. In addition, it is unclear as to why the Company has included electric ROEs as part of the equation for a natural gas asset. The Company talks about streamlining as a reason to use an aggregate ROE value but in doing so, they are asking the Commission to give up one of its main regulatory controls over an asset that will be held by an unregulated company affiliate and that will transfer to Nebraska ratepayers, a set of risks that are more appropriately borne by shareholders.

Q11. IS THE ALLOWED ROE STATIC?

A11. No. The allowed ROE will change each year based on the average ROEs reported by RRA in the previous calendar year. Given that it can change each year, the allowed ROE being paid to COSGCO could increase without express authorization from the Commission. If the allowed ROE can increase during the life of the COSG Program, it could impact the amount of Hedge Costs paid by and the Hedge Credits paid to Nebraska customers. For example, if the allowed ROE increases while natural gas prices and COSGCO incurred costs remain stable, then it becomes less likely that the sales revenue will meet the allowed ROE threshold and more likely that Nebraska customers will be assessed a Hedge Cost. It could even result in a scenario where decreasing gas prices, which would eliminate the stated benefits of the COSG Program, coupled with an increasing ROE lead to Nebraska customers funding higher profit margins for COSGCO in a decreasing price environment. Taking away the Commission's oversight of a dynamic ROE for a program that is based on uncertain forecasts and projections should raise serious concerns as to whether Nebraska ratepayer interests can be served under the COSG Program.

V. TRANSFERRING RISK FROM SHAREHOLDERS TO RATEPAYERS

Q12. IS IT TYPICAL FOR A NATURAL GAS UTILITY TO RECOVER COSTS AND AN ROE FOR THE ACQUISITION OF NATURAL GAS RESERVES THROUGH A PURCHASE GAS ADJUSTMENT ("PGA") MECHANISM AS PROPOSED IN THE APPLICATION?

A12. No. Typically, natural gas utilities are granted a regulated ROE for their distribution assets while they pass the commodity cost of gas through to their customers without profit or markup. This is logical because regulated returns are best suited for assets that can be characterized as a natural monopoly. That is to say, it is logical and more efficient to grant monopoly status to distribution assets and then regulate their return than it is to have entities competing to install overlapping and redundant distribution networks. The opposite holds true for commodity gas supply. There is great efficiency to be gained by procuring natural gas through market mechanisms like competitive wholesale markets and gas choice that allocate resources in the most effective manner. In addition, maintaining natural gas supply as a pass through helps to ensure that the risks associated with natural gas E&P and supply are allocated to supplier shareholders rather than utility customers. The Application and the COSG Program undermine the logical, separate treatment of distribution and commodity assets by using guaranteed ratepayer cost recovery to acquire natural gas reserves under COSGCO and by effectively passing a guaranteed profit on those reserves through to those ratepayers via the PGA. In doing so, the COSG Program inappropriately assigns the risk associated with commodity supply of natural gas from BHC's shareholders, through COSGCO, to the Company's ratepayers.

Q13. HAS BHC MADE PUBLIC COMMENTS IN REGARDS TO HOW THE COSG PROGRAM TRANSFERS RISK FROM ITS SHAREHOLDERS TO ITS CUSTOMERS?

A13. Yes. During BHC's 2015 Analyst Day on October 8, 2015, Brian Iverson, an executive for BHC had the following exchange with an unidentified analyst/investor:

> *Unidentified Participant:* 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)?
>
> *Brian Iverson:* 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.
>
> *Unidentified Participant:* So, that would all get loaded into the cost of the program.
>
> *Brian Iverson:* Right (ph).
>
> *Unidentified Participant:* So, the -- like, a bad well gets sucked in and spread out over everything else.
>
> *Brian Iverson:* Right.
>
> *Unidentified Participant:* So, you guys don't carry exposure to that.
>
> *Brian Iverson:* 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.[1]

[1] *See* BHC Analyst Day Transcript, Bennett Exhibit SB-2, pg 18-19

In simple terms, what Mr. Iverson seems to be saying to the analyst/investor is that the risk of the E&P business demands a return higher than that offered through regulated utility ratemaking but that BHC is willing to forego that higher return given that the COSG Program removes the exposure (i.e. the risk) from BHC.

Q14. WHAT ELSE LEADS YOU TO BELIEVE THAT THE APPLICATION AND THE COSG PROGRAM TRANSFERS RISK FROM BHC'S SHAREHOLDERS TO THE COMPANY'S CUSTOMERS?

A14. To further understand the risk transfer from shareholders to customers, first consider the scenario in which BHEP acquires natural gas reserves outside of the COSG Program. Without the COSG Program in place, BHEP would acquire those reserves without a guarantee of cost recovery or profit. BHEP and the BHC shareholders would bear all the risks inherent to owning those reserves including the risk that actual supply volumes meet the predicted supply volumes and that the reserves can be brought to market profitably over the life of the asset. In other words, BHC's shareholders bear the drilling risk, the operations and maintenance ("O&M") cost risk, the volumetric risk, and the price risk of the reserves. Now, consider the scenario proposed through the COSG Program. Under this scenario, COSGCO bears none of those risks. The COSG Program requires the Company's ratepayers to guarantee full cost recovery for the reserves. The COSG Program also requires the Company's ratepayers to guarantee COSGCO a profit on those reserves through the allowed ROE. If reserve volumes or market prices are too low to meet the cost plus profit thresholds established by the program, it is the Company's ratepayers that are on the hook, not the BHC shareholders. While the COSG Program does contemplate the possibility of rewarding Company ratepayers with Hedge Credits in the event sales revenues exceed the cost plus profit threshold, there is no guarantee that these Hedge Credits will ever be realized. Even if the Hedge Credits are realized, there is certainly no guarantee that the amount of Hedge Credits paid to ratepayers will outweigh the amount of Hedge Costs paid by ratepayers over the life of the reserve asset. In other words, there is no guarantee that the Hedge Credits paid will be commensurate with the risk ratepayers are being asked to bear. Given that the COSG Program guarantees profits to COSGCO while only providing the possibility of reward to ratepayers, it is clear that the program effectively transfers the risk of acquiring the natural gas reserves from BHC and its shareholders to the Company's ratepayers.

VI. ASKING THE CUSTOMER TO INVEST WHERE BHC WILL NOT

Q15. HAS BHC INDICATED IT WILL PURCHASE GAS RESERVES THROUGH COSGCO IF THE COMMISSION DOES NOT APPROVE THE APPLICATION FOR COST RECOVERY AND THE ALLOWED ROE?

A15. No. Company witness Vancas makes it clear in his testimony that BHC will not invest in COSGCO without first obtaining Commission approval when he states:

> While BHUH has made efforts to investigate the market and determine what options are available to acquire reserves, it is not prudent for BHUH to establish COSGCO and to invest the time, due diligence, and resources necessary to acquire gas reserves without knowing whether the COSG Program, including the related criteria and guidelines, will be approved by the Commission. COSGCO cannot justify undertaking such a sizable financial commitment without assurance that the Commission concurs.[2]

Witness Vancas also makes it clear in his testimony that the Company will not move forward with the COSG Program without Commission approval, stating:

[2] Direct Testimony - Ivan Vancas, pg 20 - 21

> The Company will not participate in the COSG Program if approval is not granted by the Commission.[3]

Taken together, the filed testimony is clear that BHC does not support the concept of purchasing natural gas reserves under the COSG Program parameters without the guaranteed profit included in the program.

Q16. IS BHC EFFECTIVELY ASKING COMPANY'S CUSTOMERS TO TAKE ON RISKS ASSOCIATED WITH THE COSG PROGRAM THAT IT IS NOT WILLING TO TAKE ON ITSELF?

A16. Yes. Testifying to how the Company proposes to "balance the interests of the company and customers under the COSG Program," Company witness Carr states:

> …to produce natural gas from an acquisition or drilling plan, it must be reasonably anticipated to be less than the long term market price forecast costs of acquiring the same volumes of gas on a net present value basis over the life of the wells…[4]

The direct testimony of Company witness Ryan is largely devoted to making the case that natural gas prices have the potential to rise over the long term. Taken together, the filed testimony of the two Company witnesses paints a picture of an opportunity to acquire natural gas reserves that can reasonably be expected to generate a profit in a purportedly rising commodity price environment. Nonetheless, witness Vancas makes it clear that BHC will not invest in COSGCO or the reserves without Commission approval of the Application. As such, one can conclude that BHC has no interest in investing in the acquisition of the natural gas reserve without the guaranteed cost recovery and allowed ROE proposed in the COSG Program. However, given that it is the Company's ratepayers that will bear the risk associated with COSG Program cost recovery and

[3] Ibid., pg 22
[4] Direct Testimony - T. Aaron Carr, pg 8

any ROE shortfalls it becomes clear that BHC are effectively asking Company's customers to make an investment that it is not willing to make itself.

VII. ECONOMIC EVALUATION MODEL

Q17. DOES THE COMPANY INCLUDE AN ECONOMIC EVALUATION MODEL FOR THE COSG PROGRAM IN ITS FILED TESTIMONY?

A17. Yes. Company witness Carr includes a spreadsheet-based economic evaluation model for the COSG program in his filed testimony as Public Version -Exhibit AC-2 COSG Model ("AC-2"). In addition, witness Carr describes and explains the model in his written testimony. Witness Carr indicates that the model is for a hypothetical COSG Program and that it is based on a mixture of historical and market data as well as several assumptions.[5] Witness Carr indicates that the assumptions include, but are not limited to, gas recovery volumes, drilling costs, and O&M costs.[6] The model uses natural gas price forecasts from the U.S. Energy Information Administration ("EIA") and a pricing service claimed as confidential by the Company. The model includes NYMEX price forecasts as well but these are not used in any of the calculations for the NPV analysis. Witness Carr describes the NPV analysis, found in section 2 on page 4 of the model, as the means by which a reserve interest would be evaluated in the context of the COSG Program.[7] Simply put, the outputs in this section show whether the forecasted revenue from the sale of the recovered natural gas would exceed or fall short of the projected total cost to recover the gas over the term of the program, given the specific input assumptions used. It should be noted, however, that the model evaluates a ten-year period while the actual reserve evaluation would be conducted over the expected twenty-year life of the asset.

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[5] Ibid., pg 20
[6] Ibid., pg 20 - 21
[7] Ibid., pg 23

Q18. DID YOU CONDUCT ANY ANALYSIS OF THE ECONOMIC EVALUATION MODEL IN AC-2?

A18. Yes. I reviewed the entire model but focused mainly on the NPV analysis in section 2 on page 4. The model, as presented in AC-2, explicitly shows the inputs used in the calculations as well as the calculation formulas themselves. As previously noted, the model includes ten years of NYMEX futures contract prices for "reference only" but these forecasts are not used in the calculations themselves. Rather, the model uses an average of EIA and price forecasts claimed as confidential by the Company for the ten-year period between 2016 and 2025. It is not clear from which EIA and claimed confidential publications the prices are taken.

It is readily apparent that the NPV analysis is largely dependent on the assumptions and forecasts used for capital spend, commodity production volumes, and commodity prices. In fact, the NPV analysis section includes a table that lists the NPV customer costs or savings calculated by the model when sensitivities of +/-5% are applied to all three inputs. The base case analysis calculated by witness Carr shows customer savings of approximately $47 million over the ten year period. The sensitivity cases show a wide range of outcomes, most of which indicate NPV customer savings over the hypothetical ten-year period. To analyze these results further, I recreated section 2 using the formulas as they are listed in the model.[8] Recreating section 2 allowed me to input additional commodity price assumptions and calculate the NPV results for customers. I used price forecasts from EIA's Annual Energy Outlook 2015 ("AEO2015").[9] I selected the Henry Hub price forecasts for 2016 – 2025 and included the base case as well as the high and low economic activity cases formulated by EIA. The high economic activity case

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[8] *See* Recreated Economic Model NPV Analysis, Bennett Exhibit SB-5

[9] EIA Annual Energy Outlook 2015 – Table 13: Natural Gas Supply, Disposition, and Prices published at http://www.eia.gov/beta/aeo/#/?id=13-AEO2015

produced a NPV customer savings of approximately $17 million. The low economic activity case produced a NPV customer cost of approximately $29 million. The base case resulted in a NPV customer cost of about $5 million. In addition, plugging in the NYMEX futures contract pricing from the model itself resulted in a customer cost of almost $70 million.

Q19. WHAT CONCLUSION DO YOU DRAW FROM YOUR ANALYSIS OF THE ECONOMIC EVALUATION MODEL IN AC-2?

A19. The main conclusion that can be drawn from the model presented in AC-2 is that the NPV analysis of customer costs or savings from the reserve asset is highly dependent on the input assumptions and forecasts. As such, the uncertainty inherent in those assumptions and forecasts will impact the accuracy of the model, its outputs, and the assessment of whether the natural gas reserve will provide any economic benefit to the customers who are ultimately being asked to take on the risk of the COSG Program. The model and the uncertainty of its inputs also show how difficult it will be for the Commission to analyze the potential for Nebraska customers to benefit from the COSG Program. Accuracy in all of the input forecasts decreases over time, with confidence levels in the price forecasts eroding rapidly after the first four or five years. The purpose of the model is to show the complex financial structure of the COSG Program and a range of hypothetical outcomes. What it mostly shows is that the Company is asking the Commission to approve a program that offers COSGCO guaranteed profits while it offers Nebraska ratepayers risk and uncertainty.

VIII. <u>USING BLACK HILLS EXPLORATION AND PRODUCTION RESERVES FOR THE COSG PROGRAM</u>

Q20. DOES BHEP OWN NATURAL GAS ASSETS IN THE SOUTHERN PICEANCE BASIN?

A20. Yes. Here is how those assets are described by witness Benton:

> One of BHEP's most significant assets is its 73,000 net acres in the Mancos Shale, a shale resource in the Southern Piceance Basin on the western slope of the Rocky Mountains in Colorado.[10]

Q21. AS PROPOSED, DOES THE COSG PROGRAM ALLOW COSGCO TO ACQUIRE NATURAL GAS RESERVE ASSETS FROM BHEP?

A21. Yes. Witness Carr explicitly indicates that the COSG Program would allow COSGCO to acquire a reserve asset from BHEP on page 12 of his direct testimony filed in this proceeding.

Q22. HAS BHC MADE ANY PUBLIC STATEMENTS ABOUT TARGETING THE MANCOS SHALE ASSETS FOR THE COSG PROGRAM?

A22. Yes. BHC hosted an Analyst Day on October 8, 2015. The Analyst Day included a written presentation and a discussion with investors and analysts that was memorialized in a transcript. These were previously noted as Bennett Exhibits SB-1 and SB-2 respectively. Slide 69 in Bennett Exhibit SB-1 is titled "Oil and Gas Strategy – Creating Shareholder Value." The slide explicitly indicates that BHC is targeting Piceance Mancos for the COSG Program.[11] The slide goes on to indicate that BHC has reduced staff levels at BHEP by 25% but has retained the staff capability to support the COSG Program.[12] BHC reiterated its interest in including the Mancos asset during its Q4 2015 Earnings Conference call when BHC Chairman, President, and CEO David Emery stated:

> Primarily just the Mancos property is the one of our own that really is a good, viable, long-term gas resource. It's a least a couple trillion cubic foot resource, potentially as much as 8. And that's the one property we have we think would be a great fit for cost of service gas.[13]

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[10] Direct Testimony - John H. Benton, pg 21
[11] *See* BHC Analyst Day Presentation, Bennett Exhibit SB-1, slide 69
[12] Ibid.
[13] BHC Q4 2015 Earnings Call Transcript posted at http://ir.blackhillscorp.com/Cache/1500080359.PDF?Y=&O=PDF&D=&fid=1500080359&T=&iid=4010420

Q23. DID ANYONE AT BHC DISCUSS THE PICEANCE MANCOS SHALE ASSETS WITH THE INVESTMENT ANALYSTS ON THE OCTOBER 8, 2015 ANALYST CALL?

A23. Yes. Witness Benton participated in the analyst call on October 8th and explicitly discussed the Piceance Mancos asset. The transcript from the call captures the discussion:

> *Jerome Nichols:* Welcome back. Next up is John Benton, who is our Vice President and General Manager of Oil & Gas, and he'll give an update on our oil and gas business and strategy transition. John?
>
> *John Benton:* Thank you. Thank you, Jerome, and thank you for all coming your afternoon, and devoting your afternoon and time to hear all of our stories.
>
> Since last year, there's a lot that's changed in the upstream oil and gas business, since we were -- spoke to you about a year ago. Both oil and gas prices started their fall last fall, and started to decline. We adjusted to that last fall by reducing some of our oil exploration efforts. We went back -- of course, the usual thing: worked with our suppliers and our contractors to reduce our costs overall, so we can continue some of our programs.
>
> By the second quarter of 2015, it was clear that excess oil and gas production supply had transformed the energy market. Our exploration appraisal programs had showed some promise, but the economics did not support our 2016 and '17 capital program, so we made some changes. We reduced our planned capital spending, as Dave mentioned earlier, to amounts that were just necessary -- needed to maintain our leases and our existing production.
>
> We had some great Piceance well results to date -- allowed us to defer the last four completions we had in the plan for the program for this year. Also, we ended up with some impairments as a result of the low prices -- had to make a difficult decision, and reduced our staffing levels by about 25%, and started looking at potential monetization of some of our non-core unprofitable assets.[14]

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[14] *See* BHC Analyst Day Transcript, Bennett Exhibit SB-2, pg 27

Q24. WHAT ARE THE MOST IMPORTANT TAKE-AWAYS FROM THE BHC ANALYST DAY?

A24. First, it is important to note that BHC included its plans to use the Mancos asset for the COSG Program in the written presentation provided to the investment analysts.[15] The Application indicates that the reserve acquisition target is open and yet to be determined. However, the analyst presentation and discussion seem to indicate that the asset decision has already been made.[16]

Second, witness Benton notes that the excess oil and gas production has "transformed the energy market" as he describes BHEP's significant reductions in capital spending.[17] BHEP determined that it would be uneconomic and ostensibly risky to drill new reserves in 2016 but that is precisely what the COSG Program proposes to do.[18] It is a clear indication of the Company asking ratepayers to invest where the experts at BHEP will not.

Third, witness Benton talks about impairments the company has suffered due to "low prices."[19] As reported in a press release entitled "Black Hills Corp. Reports 2015 Fourth Quarter and Full Year Results," BHC reports Oil & Gas segment Q4 and full-year operating losses of $77M and $277M respectively.[20] These losses include impairment of long-lived assets of $71M in Q4 and $250M for the full year.[21]

The current low gas price environment is clearly taking a toll on BHEP. BHEP is cutting capital investment, cutting staff, and booking significant impairments on its reserve assets. As BHEP is absorbing these negative impacts and impairments, it is targeting its Mancos assets for the COSG

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[15] *See* BHC Analyst Day Presentation, Bennett Exhibit SB-1, slide 69
[16] Ibid.
[17] *See* BHC Analyst Day Transcript, Bennett Exhibit SB-2, pg 27
[18] Ibid.
[19] Ibid.
[20] BHC press release posted at http://ir.blackhillscorp.com/file.aspx?IID=4010420&FID=32776001
[21] Ibid.

Program. BHC has presented the COSG Program as a kind of volatility hedge for its customers. Taken in total, BHC's public commentary with the investor community indicate that the COSG Program may be more of a hedge for its BHEP subsidiary than for the Company's ratepayers.

Q25. GOING BACK TO THE ECONOMIC EVALUATION MODEL IN AC-2, COULD BHC USE THE INPUTS SPECIFIC TO THEIR MANCOS ASSET TO PROVIDE A MORE INDICATIVE NPV ANALYSIS ON THE COSG PROGRAM?

A25. Yes. In testimony, the Company is very clear that the model in AC-2 is hypothetical. It is meant to educate and inform parties to the docket as to the mechanisms and formulas underlying the COSG Program. The outputs of the model and the NPV analysis of cost or savings are not indicative and do not represent the outcomes of a specific reserve asset. However, given the statements made by BHC at its October 8, 2015 analyst day, as reiterated during its Q4 2015 Earnings Conference call, it seems clear that the Company is targeting its own Mancos asset for the COSG Program. In addition, the Company has indicated that the Mancos asset could meet the total volumetric requirement for the COSG Program with room to spare. As such, the Company could run the model using real inputs based on their own Mancos asset and the most recent EIA and/or claimed confidential price forecasts to provide indicative results for the NPV analysis. Understandably, the Company would want to keep a model with proprietary information confidential from their competitors that are party to the case but there should be no reason to maintain confidentiality with the Commission, Commission Staff, and the Office of the Consumer Advocate.

The absence of an indicative economic model raises questions with the Application. By its own admission, BHC has E&P expertise through BHEP. Through its public comments on its analyst day, BHC has made it clear that the Mancos asset is the leading candidate for the COSG Program. Given this explicit experience with its own candidate asset, the Company should be able to model the projected recovery volumes and drilling costs at an indicative level. Marrying those projections with clearly identifiable and current price forecasts should provide the Commission with a reasonable indication of how the COSG Program will impact customers. To be clear, because of the uncertainty of actual volumes, costs, and prices over the twenty-year asset life, no model can guarantee the outcomes of the COSG Program. Nonetheless, with the Company asking for guaranteed profits underwritten by its captive customers, it has an obligation to provide the most accurate and up-to-date projections available to the Commission. The transfer of risk to customers inherent to the COSG Program is already a questionable proposition. It is certainly not one that the Commission should be asked to approve blindly.

IX. OTHER COST OF SERVICE GAS PROGRAMS AS REFERENCED IN COMPANY TESTIMONY

Northwest Natural Gas Company

Q26. HAVE YOU REVIEWED THE "LONG-TERM PHYSICAL HEDGE PROGRAM" IMPLEMENTED BY NORTHWEST NATURAL GAS IN OREGON AND REFERENCED IN WITNESS VANCAS'S TESTIMONY?

A26. Yes. Witness Vancas references certain long-term physical hedge programs in his testimony as examples of how other regulated utilities are crossing the line into cost-of-service ratemaking for reserve assets.[22] One of the programs specifically mentioned was implemented by Northwest in Oregon beginning in 2011. I reviewed the program using publicly available documents filed with the OPUC. There are notable difference between the Northwest program and the COSG Program. The Northwest program proposed a lower natural gas reserve supply target than the COSG Program, limiting it to only 10% of its portfolio. Unlike the COSG Program that seeks a

[22] Direct Testimony - Ivan Vancas, pg 12 - 13

finding of prudency without naming a reserve asset, or even a candidate list of reserve assets, the Northwest program explicitly named the Jonah field in Wyoming's Green River Basin for use in the program. Northwest also agreed to cap its 5-year capital expenditures at approximately $251 million.[23] Additionally, Northwest agreed to allow the OPUC to set the ROE for the project on an ongoing basis. Finally, Northwest provided an average cost of gas estimate of $5.15/dekatherm.[24] In simple terms, the Northwest program provided more concrete projections for a named asset on a smaller percentage of program supply with capped capital costs.

Q27. WHAT INFORMATION AND CONCLUSIONS CAN BE DRAWN FROM THE NORTHWEST PROGRAM TO DATE?

A27. First, look at the cost of gas estimate of $5.15/dekatherm in the Northwest program. On one hand, Northwest actually provided a cost of gas estimate for their program. On the other hand, that estimate is significantly higher than the cost of gas in 2011/2012 when the program was approved and remains above current and near-term projected gas prices. In fact, EIA's AEO2015 Base Case price forecasts for Henry Hub do not reach-or-exceed $5.15/dekatherm until 2023, a full 12 years after the Northwest program was proposed.[25]

Second, a review of documents filed by Northwest subsequent to the approval of the Northwest program indicate that the actual supply volumes from the Jonah field were lower than originally anticipated when the program was approved. A prudency request filed by Northwest in February 2015, included testimony from Northwest witness Barbara Summers where witness Summers says:

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[23] OPUC Order 11-176 posted at http://apps.puc.state.or.us/edockets/orders.asp?OrderNumber=11-176
[24] Ibid.

[25] EIA Annual Energy Outlook 2015 – Table 13: Natural Gas Supply, Distribution, and Prices published at http://www.eia.gov/forecasts/aeo/excel/aeotab_8.xlsx

> Due to lower well production than had been forecast, and also due to some changes to the drilling schedule, NW Natural was receiving lower volumes than it had expected at the time it entered the Original Agreement[26].

These lower volumes were realized despite the fact that the Northwest program proposed a known field that was under production with existing wells.

In summary, the Northwest program is one that is referenced by the Company as an example in support of the COSG Program. However, it is unclear that the reference is appropriate. The Northwest program is materially different from the COSG Program as proposed, notably in its size, capped costs, and named asset. Moreover, even with a named asset, the program has produced gas at a cost well above current and near-term forecasted prices while supplying gas volumes that were below original forecasts. The Northwest program is more of a cautionary reference than a supportive one.

Washington Gas Light

Q28. HAVE YOU REVIEWED THE "LONG-TERM PHYSICAL HEDGE PROGRAM" PROPOSED BY WASHINGTON GAS LIGHT IN VIRGINIA AND REFERENCED IN WITNESS VANCAS'S TESTIMONY?

A28. Yes. As previously noted, witness Vancas references certain long-term physical hedge programs in his testimony as examples of how other regulated utilities are crossing the line into cost of service ratemaking for reserve assets.[27] Another of the programs specifically mentioned was proposed by WGL in Virginia in May 2015. I reviewed the program using publicly available documents filed with the Virginia SCC. The COSG Program and the WGL program are similar in that both propose to purchase an interest in natural gas reserve assets for 20 years.

[26] *See* OPUC UM 1717 Northwest Gas Prudency Review Filing - Bennett Exhibit SB-3, pg 7
[27] Direct Testimony – Ivan Vancas, pg 12 - 13

The programs differ in that the WGL program proposed to physically deliver the gas from the reserve asset to its customers and in that the WGL program proposes specific, named reserve assets for the program. The supply targets in the WGL program are required to be smaller than the COSG Program because the Virginia statute that allows the SCC to assess and authorize a program like WGL's limited the volumes to no more than 12.5% of the company's Virginia portfolio for each project and no more than 25% of the company's Virginia portfolio in total. Notably, the Virginia legislature mandated by statute that total program volumes could be no more than half of what the Company is proposing through the COSG Program.

Q29. DID THE SCC APPROVE THE WGL PROGRAM AS PROPOSED?

A29. No. The SCC denied the WGL application through an order dated November 6, 2015. In its order denying the program, the SCC noted numerous concerns with the uncertainty of the forecasts and projections that WGL used to support the program. In addition, the SCC called into question whether the program, as proposed, would provide any benefit to the customer. Specifically, the SCC noted the risk transfer from WGL shareholders to Virginia ratepayers:

> Under the specifics of the proposed Plan, the potential harm to customers is too great when compared to the potential benefits. The Company admits that, from the moment the Commission approves the Plan as proposed in the Application, WGL's customers would bear all of the Plan's risks and WGL (and its shareholders) would bear none of those risks.[28]

The SCC noted the supply risk inherent to the plan:

> In this regard, the Company's customers bear the risks associated with production volumes from these wells falling short of WGL's projections. WGL witness Wright acknowledged that his estimates of the natural gas reserves and production volumes are

[28] *See* VA SCC PUE-2015-00055 Denial of WGL Application - Bennett Exhibit SB-4, pg 8

> just that - estimates - and there remains a risk that production volumes could fall below the levels needed for customers to reap any savings benefit.[29]

The SCC also noted the price risk and forecast uncertainty inherent to the plan:

> The Company's customers also bear the risk if WGL's 20-year price forecast is overstated. The statute does not require the Commission to accept, without review or analysis, any single long-term forecast produced by the Company for purposes of evaluating whether the Plan is in the public interest. No party contested that forecast confidence generally decreases as the forecast period extends, and, in this instance, the 20-year plan requires a 20-year forecast.[30]

Finally, the SCC noted the risk of increasing capital and variable costs inherent to the plan:

> The Company's customers also bear the risks associated with certain variable costs. That is, only the commodity cost is fixed over the 20-year life of the Plan. There are numerous variable costs that are not fixed, including operation and maintenance expenses, future regulatory compliance and taxation costs, and changes in WGL's cost of capital[31].

Once again, it seems as if the Company has referenced a program that is more cautionary than supportive to its request for a finding of prudency and authorization. As noted above, an important difference between the WGL program and the COSG Program is that the WGL program identifies specific reserve assets. In addition, the WGL program would have to be smaller on a volume basis than the COSG Program. Nonetheless, the SCC pointedly denies the program based on the very same questions of risk transference and forecast uncertainty that makes up the basis of my testimony in this proceeding. Obviously, this is not Virginia and the Commission needs to analyze the specifics of the COSG Program and make a decision that is best for Nebraska ratepayers. However, the SCC provides the Commission with a roadmap and a strongly worded caution as to whether it is possible to truly assess a program that transfers

[29] Ibid.
[30] Ibid., pg 9
[31] Ibid., pg 10

significant risk to ratepayers when the basis of that assessment is rife with so much uncertainty and speculation.

Q30. DID YOU REVIEW THE WEXPRO I AND WEXPRO II PROGRAMS REFERENCED BY WITNESS VANCAS?

A30. Yes. And once again, I found important distinctions between the Wexpro agreements and the COSG Program proposal that call into question whether the reference is appropriate. The most significant difference between the Wexpro agreements and the COSG Program is that Wexpro must acquire the reserve asset at its own risk before it can be proposed for cost-of-service treatment.[32] On its own, this difference is enough to remove any attempt to equate the COSG Program to the Wexpro agreements. Wexpro, unlike COSGCO, bears the risk of non-producing wells.[33] Wexpro must make its reserve assets in the agreement area available to cost-of-service treatment under a right of first refusal by the Utah and Wyoming Public Service Commissions.[34] This ensures that Wexpro is not withholding premium assets from and including less valuable or less profitable assets in the Wexpro agreements. Finally, the monitors that advise the regulators responsible for overseeing the Wexpro agreements, while paid for by Questar, are not hired by either of the participating Wexpro companies. This helps to alleviate the potential for conflicts of interest or bias on the part of the monitors.

X. <u>CONCLUSION AND SUMMARY OF ALL RECOMMENDATIONS</u>

Q31. WHAT ARE YOUR RECOMMENDATIONS AS TO THE APPLICATION IN THIS PROCEEDING?

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[32] *In the Matter of the Application of the Questar Gas Company for Approval to Include Property Under the Wexpro II Agreement*, Docket No. 30010-134-GA-13, Report and Order (March 18, 2014).
[33] Ibid. pg 2.
[34] Ibid.

A31. The Company is asking a lot of the Commission. It has presented the Commission with a program that has exactly one guarantee; that COSGCO will make a profit on a natural gas reserve asset. It is a program that transfers risks that would otherwise be borne by BHC shareholders to the Commission's constituent ratepayers. It is a program that asks these ratepayers to invest where BHC and its shareholders have demonstrated that they will not and, in fact, are not investing. It is also a program that is seemingly open to a candidate pool of qualifying assets but is in actuality, according to BHC's public statements, targeted as a means to monetize one of BHC's impaired assets. In support of its Application, the Company has provided the Commission with a hypothetical model that relies on a number of uncertain price, volume, and cost forecasts to provide a hypothetical assessment of costs and benefits to Nebraska ratepayers. The Company has also provided references to other cost of service, physical gas programs as a means to assuage concerns over the risks of the COSG Program in Nebraska. At least three of these references, however, do not clearly support the Company's request for prudency. Two of these programs are much smaller than the COSG Program on a volumetric basis. Even with a specifically targeted asset, the Northwest program dealt with deficient volumes and high prices. The WGL program was pointedly denied by the SCC, largely for the risks and uncertainties that are fundamental to the COSG Program itself. The Wexpro agreements have a significantly different risk profile that attempts to shield customers from the bulk of the E&P risk. For these reasons as explained in the body of this testimony, my recommendation is for the Commission to deny the COSG Program as proposed.

Q32. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A32. Yes, although I reserve the right to further supplement testimony as necessary and allowed.

CONSTELLATION NEWENERGY-GAS DIVISION, LLC

EXHIBIT SB-1

OF

STEPHEN BENNETT DIRECT TESTIMONY

IN THE MATTER OF THE APPLICATION OF BLACK HILLS NEBRASKA GAS UTILITY COMPANY, LLC D/B/A BLACK HILLS ENERGY FOR APPROVAL OF ITS GAS HEDGE AGREEMENT WITH BLACK HILLS UTILITY HOLDINGS, INC.

APPLICATION NO. NG-0086

BKH 2015

BKH Analyst Day

Oct. 8, 2015

Black Hills Corporation
Improving life with energy

Agenda

Welcome	*Jerome Nichols – Director of Investor Relations*
Introduction and Strategic Overview	*David Emery* *Chairman, President & CEO*
Segment Presentations	*Linn Evans – President & COO – Utilities* *Brian Iverson – Senior Vice President, Regulatory and Government Affairs and Assistant General Counsel* *Mark Lux – Vice President & General Manager Power Delivery* *John Benton – Vice President & General Manager Oil & Gas* *Rich Kinzley – Senior Vice President and CFO*
Closing Remarks	*David Emery* *Chairman, President & CEO*

Investor Relations Information

COMPANY INFORMATION

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NYSE Ticker: **BKH**
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BKH LISTED NYSE

FORWARD LOOKING STATEMENTS

This presentation includes "forward-looking statements" as defined by the Securities and Exchange Commission, or SEC. We make these forward-looking statements in reliance on the safe harbor protections provided under the Private Securities Litigation Reform Act of 1995. All statements, other than statements of historical facts, included in this presentation that address activities, events or developments that we expect, believe or anticipate will or may occur in the future are forward looking statements. This includes, without limitations, the anticipated benefits and the closing date of the acquisition of SourceGas Holdings LLC and our guidance assumptions. These forward-looking statements are based on assumptions which we believe are reasonable based on current expectations and projections about future events and industry conditions and trends affecting our business. However, whether actual results and developments will conform to our expectations and predictions is subject to a number of risks and uncertainties that, among other things, could cause actual results to differ materially from those contained in the forward-looking statements, including without limitation, the risk factors described in Item 1A of Part I of our 2014 Annual Report on Form 10-K filed with the SEC, and other reports that we file with the SEC from time to time, and the following:

- The accuracy of our assumptions on which our earnings guidance is based;
- Our ability to meet our strategic objectives, listed on slide 9;
- Our ability to receive regulatory approvals for announced acquisitions and to successfully close and implement the transactions;
- Our ability to obtain adequate cost recovery for our utility operations through regulatory proceedings and favorable rulings in periodic applications to recover costs for capital additions, plant retirements and decommissioning, fuel, transmission, purchased power and other operating costs, and the timing in which new rates would go into effect;
- Our ability to obtain regulatory approval to include additional generation in rate base in the future, and to implement a cost of service gas program;
- Our ability to obtain regulatory approval to construct a 144-mile electric transmission line and the Peak View wind project;
- Our ability to complete our capital program in a cost-effective and timely manner;
- The impact of the volatility and extent of changes in commodity prices on our earnings and the underlying value of our oil and gas assets, including the possibility that we may be required to take impairment charges under the SEC's full cost ceiling test for natural gas and oil reserves;
- Our ability to provide accurate estimates of proved crude oil and natural gas reserves and future production and associated costs; and
- Other factors discussed from time to time in our filings with the SEC.

New factors that could cause actual results to differ materially from those described in forward-looking statements emerge from time-to-time, and it is not possible for us to predict all such factors, or the extent to which any such factor or combination of factors may cause actual results to differ from those contained in any forward-looking statement. We assume no obligation to update publicly any such forward-looking statements, whether as a result of new information, future events or otherwise.

Introduction

Cheyenne Prairie Generating Station
Cheyenne, Wyoming

Today's Objectives

Engage with our leadership team

Review our long-term growth strategy

Provide operational, financial and guidance updates

Review our value proposition and track record

Black Hills Corporation is a utility-centered energy company well positioned to extend our track record of earnings growth

Today's Presenters

David Emery
Chairman, President and CEO

Sr. Management

Linn Evans
President and COO Utilities

Rich Kinzley
Senior Vice President and CFO

Brian Iverson
Senior Vice President, Regulatory and Government Affairs and Assistant General Counsel

Segment Vice Presidents

Mark Lux
Vice President and General Manager Power Delivery

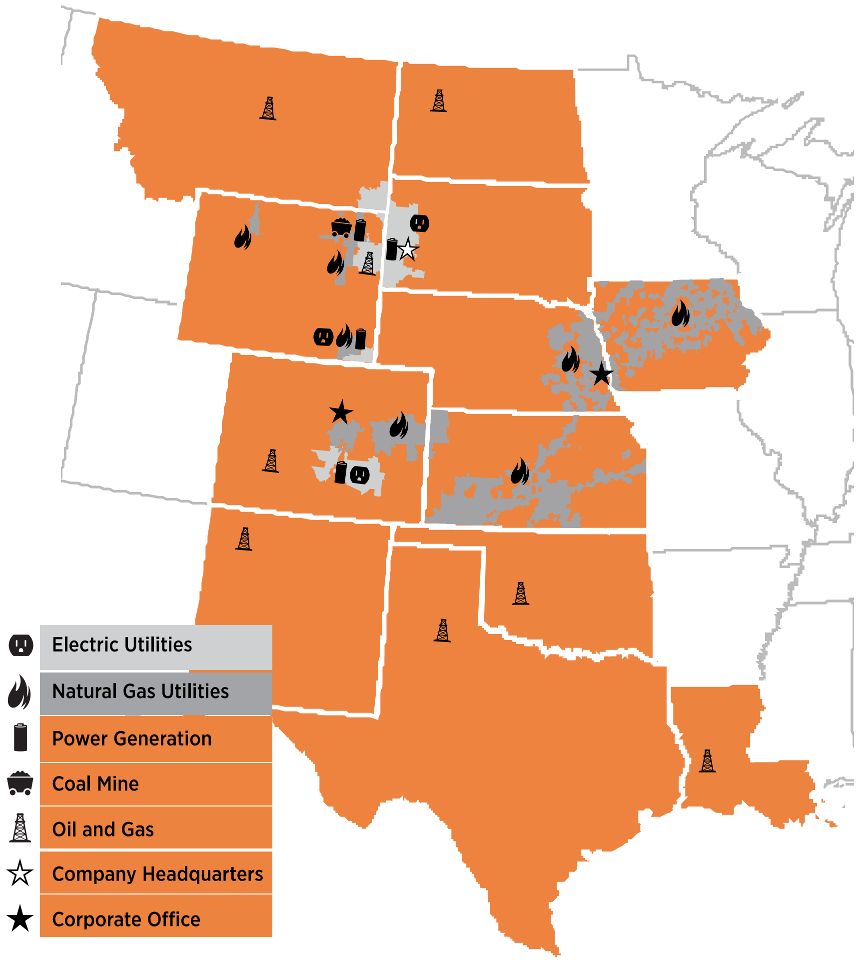
John Benton
Vice President and General Manager Oil & Gas

Strategic Updates

- SourceGas acquisition
- Cost of service gas program
- Oil and Gas strategy
- Peak View wind project
- Colorado IPP strategic review

Black Hills Corporation Overview

A growth-oriented, vertically-integrated energy company with a tradition of exemplary service and a vision to be the energy partner of choice. Based in Rapid City, S.D., the company serves 792,000 electric and gas utility customers in Colorado, Iowa, Kansas, Montana, Nebraska, South Dakota and Wyoming. The company generates wholesale electricity and produces natural gas, crude oil and coal. Employees partner to produce results that ***improve life with energy.***



Utilities, Power Generation & Fuel Production

Utilities

Electric Utilities

- Black Hills Power
- Cheyenne Light*
- Colorado Electric

Gas Utilities

- Colorado Gas
- Iowa Gas
- Kansas Gas
- Nebraska Gas

Non-Regulated Energy

Power Generation

- Black Hills Electric Generation

Coal Mining

- Wyodak Resources

Oil and Gas

- Black Hills Exploration and Production

* Utility supplies electric and gas service to Cheyenne, Wyoming and vicinity and gas service to northeast and northwest Wyoming

Strategic Objectives

Utility-centered energy company well positioned to build upon a track record of successful utility growth

PROFITABLE GROWTH

Achieve consistent growth that creates value.

EARNINGS: Lead industry peers in earnings growth

EARNINGS UPSIDE: Capture value upside through Mancos Shale development in support of cost-of-service gas program

DIVIDEND: Increase annual dividend, extending industry-leading dividend history

CREDIT RATING: Maintain solid investment-grade senior unsecured credit rating

BUSINESS DEVELOPMENT: Grow our core energy businesses through investments in organic business expansions and acquisitions that exceed our established hurdle rates and are accretive to earnings

VALUED SERVICE

Deliver reliable, highly valued products and services.

CUSTOMER: Provide quality products and services that cost effectively meet or exceed customer expectations with increased use of technology; effectively market these products and services to customers; and, share information to create understanding of energy-related issues

COMMUNITIES: Be a partner in growing the economies of the communities we serve

BETTER EVERY DAY

Continuously improve to achieve industry leading results.

OPERATIONAL PERFORMANCE: Achieve top-tier operational performance in a culture of continuous improvement

EFFICIENCY: Continuously engage BHC employees to identify and pursue efficiencies, and to simplify or eliminate unnecessary processes. Sustain annual improvements to metrics comparing costs as a percent of gross margin

EFFECTIVENESS: Identify the right projects and tools that allow employees to work effectively every day

MEASUREMENT: Benchmark our costs and processes with meaningful metrics to assist with real-time business management assessment of results and accountability

GREAT WORKPLACE

Promote a workplace that inspires individual growth and pride in what we do.

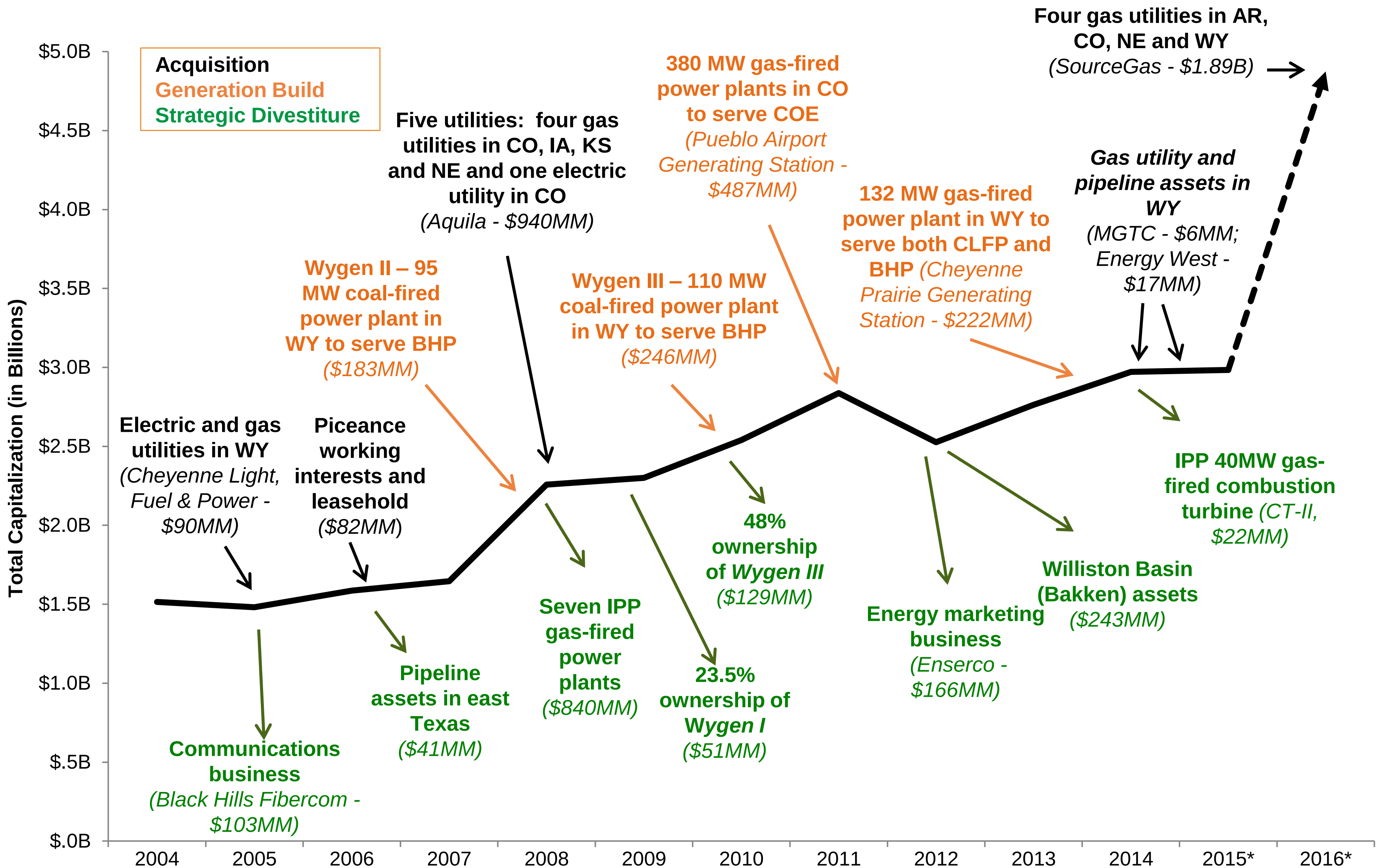
ENGAGEMENT: Achieve status as one of the "100 Great Places to Work" as measured by the Great Places to Work Institute

DIVERSITY: Increase workforce diversity (as measured as a percent of total workforce) to achieve improved performance and the innovations that come from inclusiveness

EMPLOYEE DEVELOPMENT: Establish robust development options enabling increased performance while preparing employees for additional career opportunities

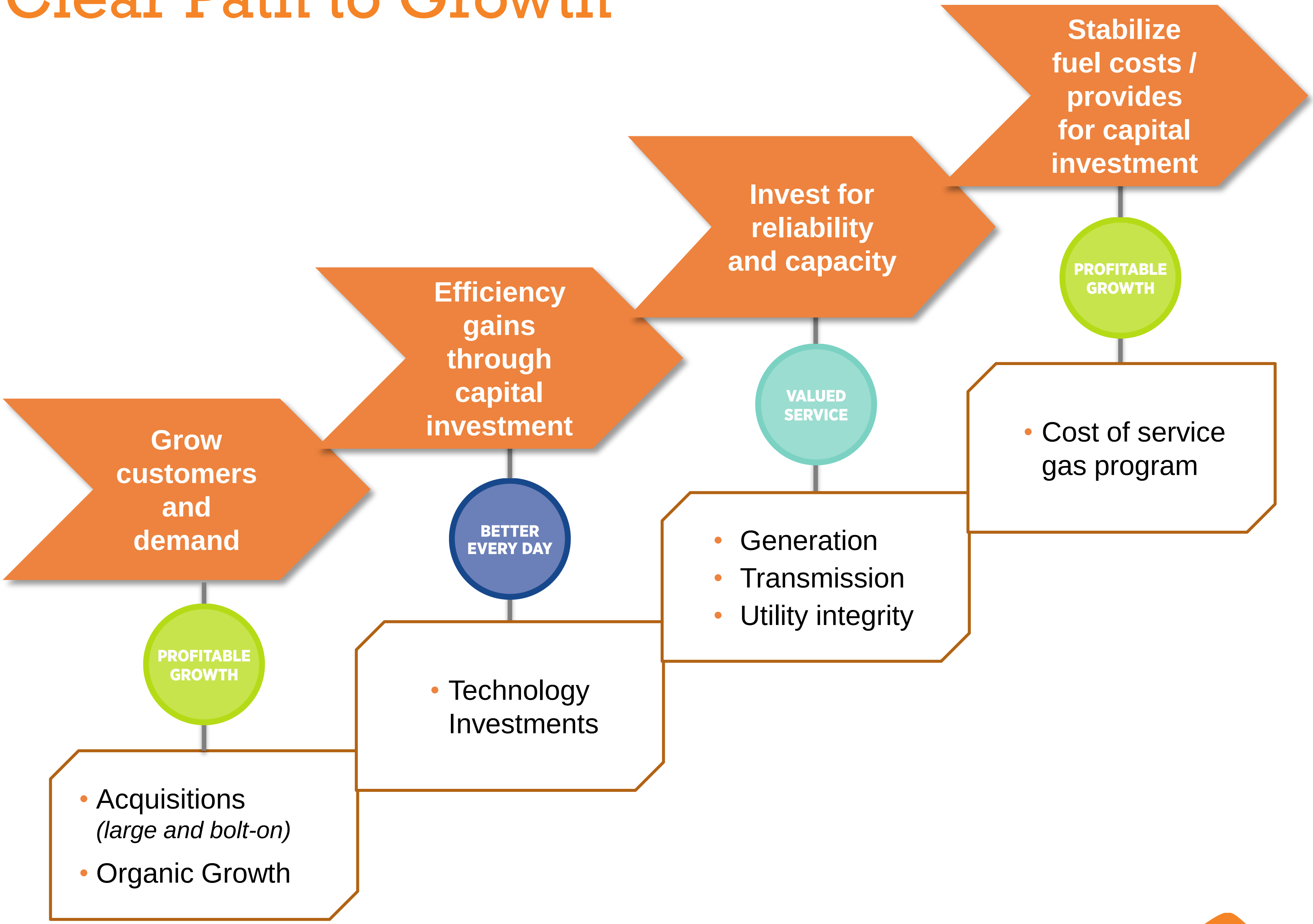
TEAM WORK: Maintain top quartile results within a professional, and productive work environment

Utility-Focused Strategy Execution



* Total capitalization as of June 2015; SourceGas acquisition expected to close in first-half 2016

Clear Path to Growth



PROFITABLE GROWTH

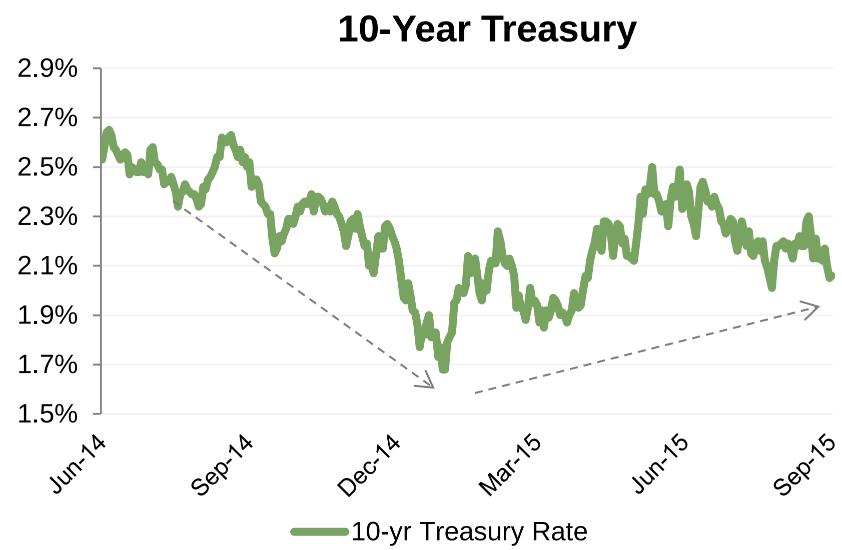
Growth Through Increased Utility Focus

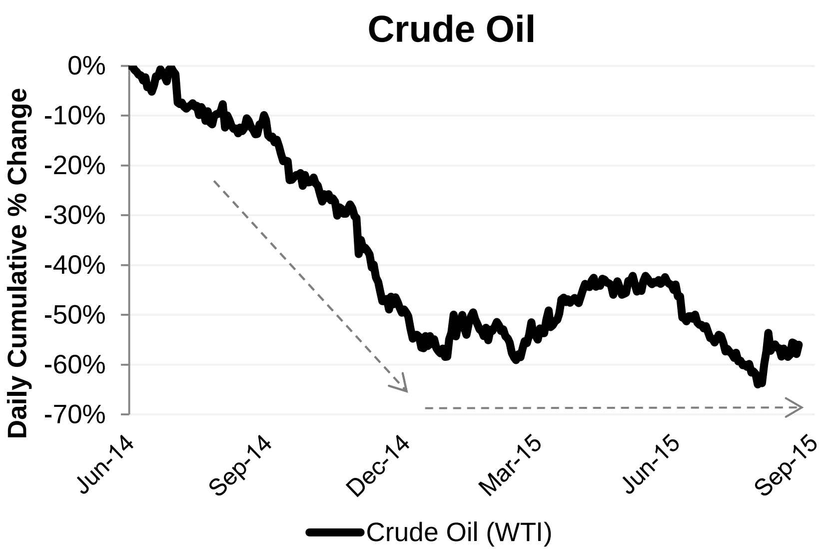
SourceGas Acquisition

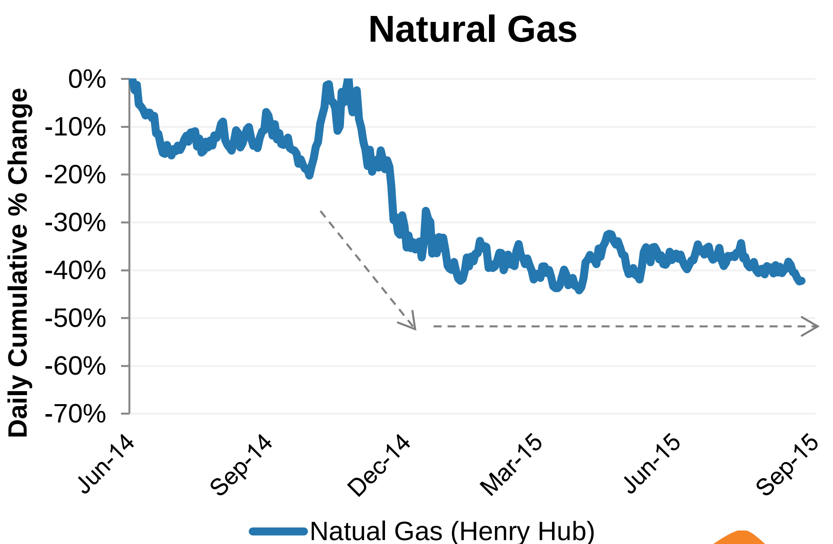
- SourceGas acquisition strengthens utility-centered focus – largest transaction in company history provides substantial increase in scale
- Successfully integrated 19 electric and natural gas utility systems over the last decade: CLFP, Aquila, Energy West, MGTC and smaller systems
- Aquila acquisition in 2008 resulted in uniform, scalable systems, integrated processes and experienced leadership team that enables future integration to be timely and efficient
- Growth strategy, target profile and integration experience builds platform for future acquisition success
- Utilize balance sheet strength and evaluate strategic options to efficiently fund acquisition

Business Environment

- Rising interest rates and uncertainty surrounding potential rate hikes
- Low commodity prices
- Sluggish economic growth
- Rising utility costs and rates (compliance and regulation)
- Distributed generation and renewables





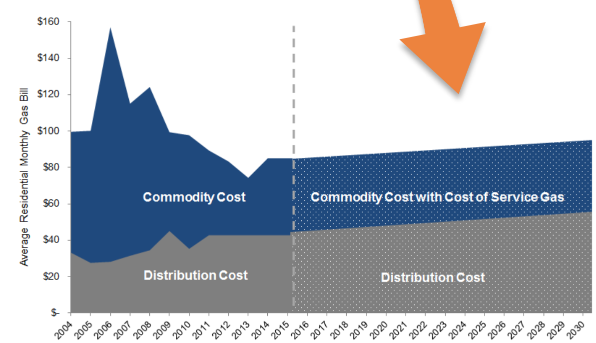


Repositioning Oil & Gas

BETTER EVERY DAY

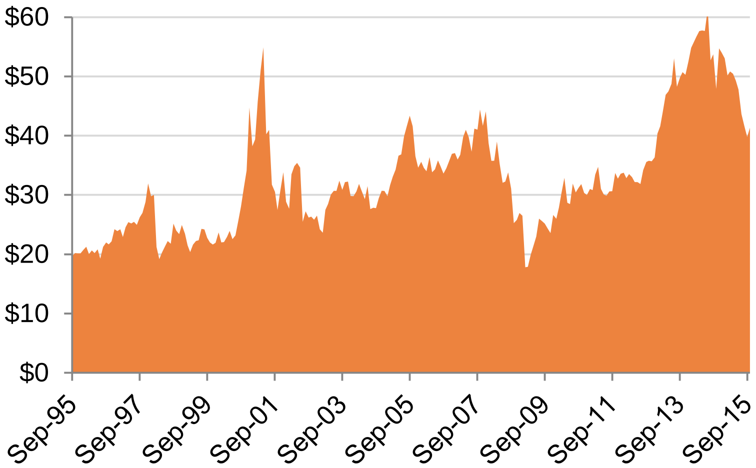
- Transitioning Oil and Gas business toward “cost of service” gas program for gas and electric utilities
- Significantly reduced planned capital expenditures
- Opportunistic monetization of non-core assets

- Utility cost of service gas model provides life-of-well price hedge for customers while providing attractive investment opportunities
- Regulatory approval process underway

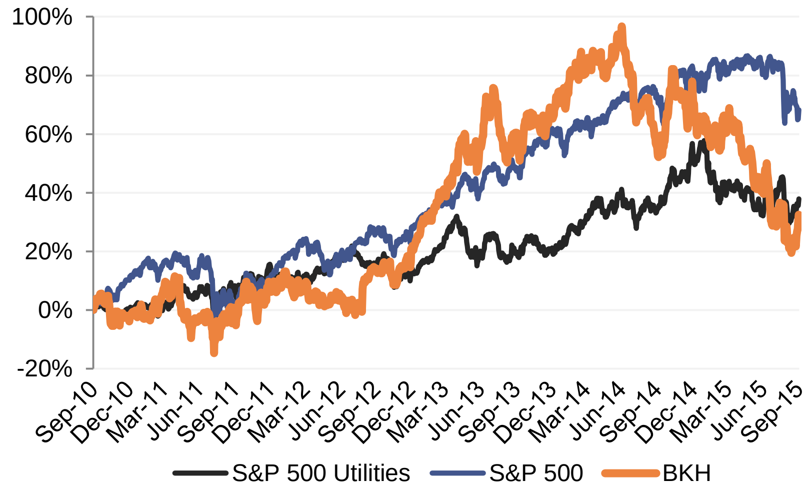


BKH Performance

Monthly Closing Stock Price



5 Year Cumulative Return



Period	Beginning Stock Price*	Ending Stock Price*	Annual Total Return**
1 Year	$46.31	$41.34	-10.7%
3 Year	$32.28	$41.34	8.6%
10 Year	$28.74	$41.34	3.7%
20 Year	$7.02	$41.34	9.2%

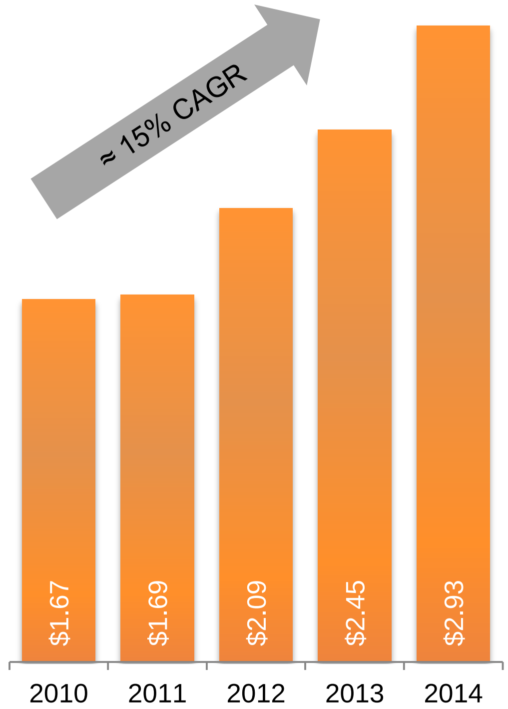
BKH
LISTED
NYSE®

* Closing prices adjusted for dividends and stock splits ** Average annualized total returns calculated from listed return period ending September 30, 2015

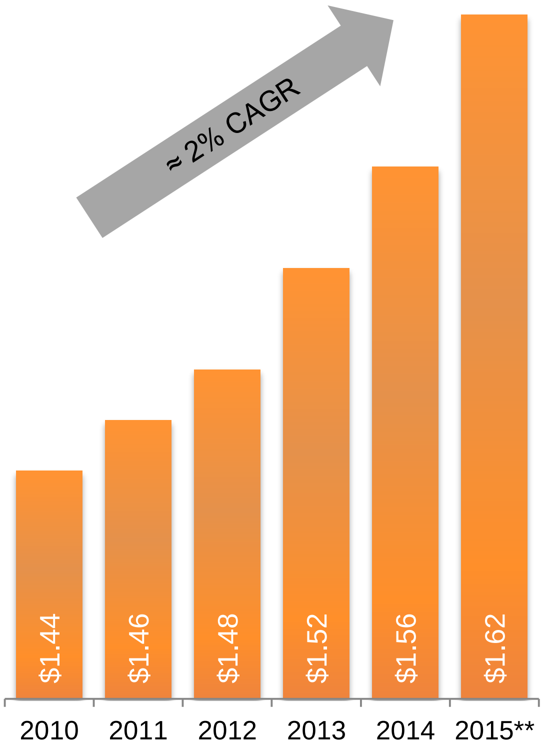
Notes: Annual total stock returns calculated on www.buyupside.com using stock return calculator. Total stock return considers dividends paid and stock splits. Black Hills Corporation does not guarantee the accuracy of these calculations, does not suggest our stock price will perform in the future comparable to the past, and does not provide this information as investment advice.

Delivering Attractive Shareholders Returns

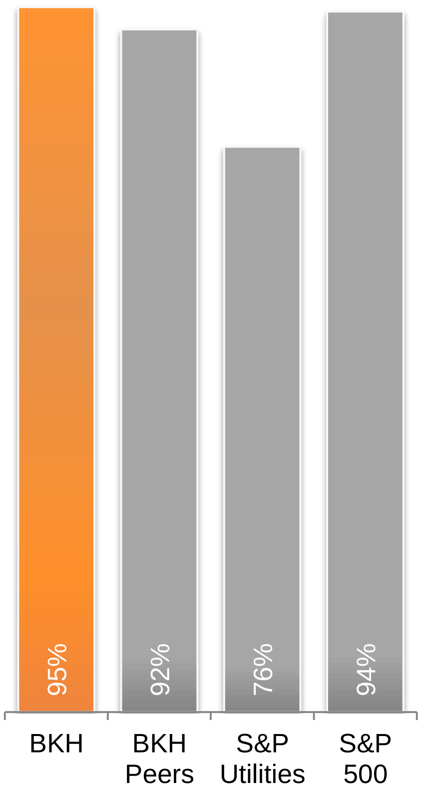
EPS, as adjusted *



Annual Dividend



Total Shareholder Return 12/31/09 - 9/30/15



* Non–GAAP measure, reconciled to GAAP in Appendix

** Quarterly dividend of $0.405 per share, equivalent to an annual dividend of $1.62 per share

Investment Highlights

- Utility-centered energy company
- Strong earnings growth track record
- Dividend increases with solid yield
- Strong balance sheet and commitment to strong investment grade credit ratings
- Disciplined approach to acquisitions creates additional growth opportunities
- Oil and gas strategy transition improves business risk profile and provides utility growth opportunity

Utilities Update

Linn Evans – President & COO - Utilities

Brian Iverson – Senior Vice President, Regulatory and Government Affairs and Assistant General Counsel

Black Hills Corporation
Improving life with energy

Utility Strategy

PROFITABLE GROWTH

- Invest in generation, transmission and distribution growth and integrity projects
- Invest capital to reduce pass-through and O&M expenses to benefit both customers and shareholders
- Pursue cost of service gas program to provide long-term price stability for customers, while providing opportunities for increased earnings
- Pursue utility organic growth opportunities such as pipeline extensions, local distribution company (LDC) acquisitions and propane customer conversions

VALUED SERVICE

- Deliver customer value by striving for top quartile customer service and reliability
- Develop/enhance effective relationships with customers, business partners, government officials, regulators and communities
- Ensure strong corporate culture of compliance

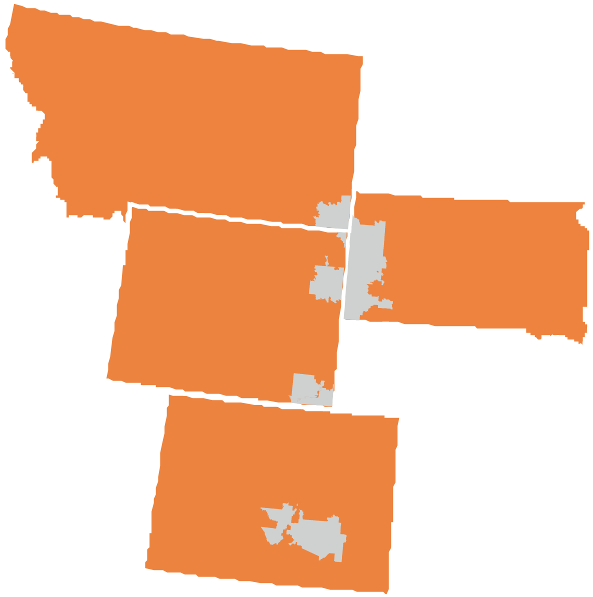
BETTER EVERY DAY

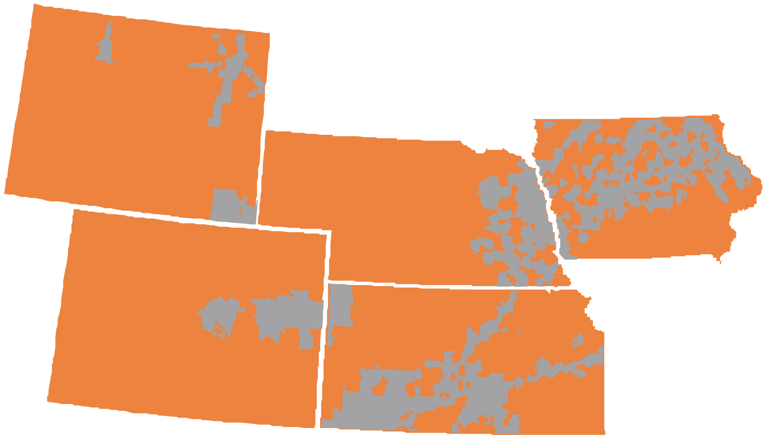
- Instill a culture of continuous business improvement
- Integrate technological tools/efficiencies throughout the business

GREAT WORKPLACE

- Become the safest energy company in the country
- Ensure public and employee safety
- Drive retention and productivity via high engagement levels and effective management

Electric and Gas Utilities





Electric Utilities*

- Generates, transmits and distributes electricity to approximately 206,000 customers
- Operations include Black Hills Power (SD, WY and MT), Cheyenne Light (WY) and Colorado Electric (CO)
- Includes 841 MW of generation and 8,565 miles of transmission and distribution lines
- East-West interconnection located near Rapid City, SD optimizes the off-system sale of power and improves system reliability (1 of only 7 east-west ties)

Natural Gas Utilities*

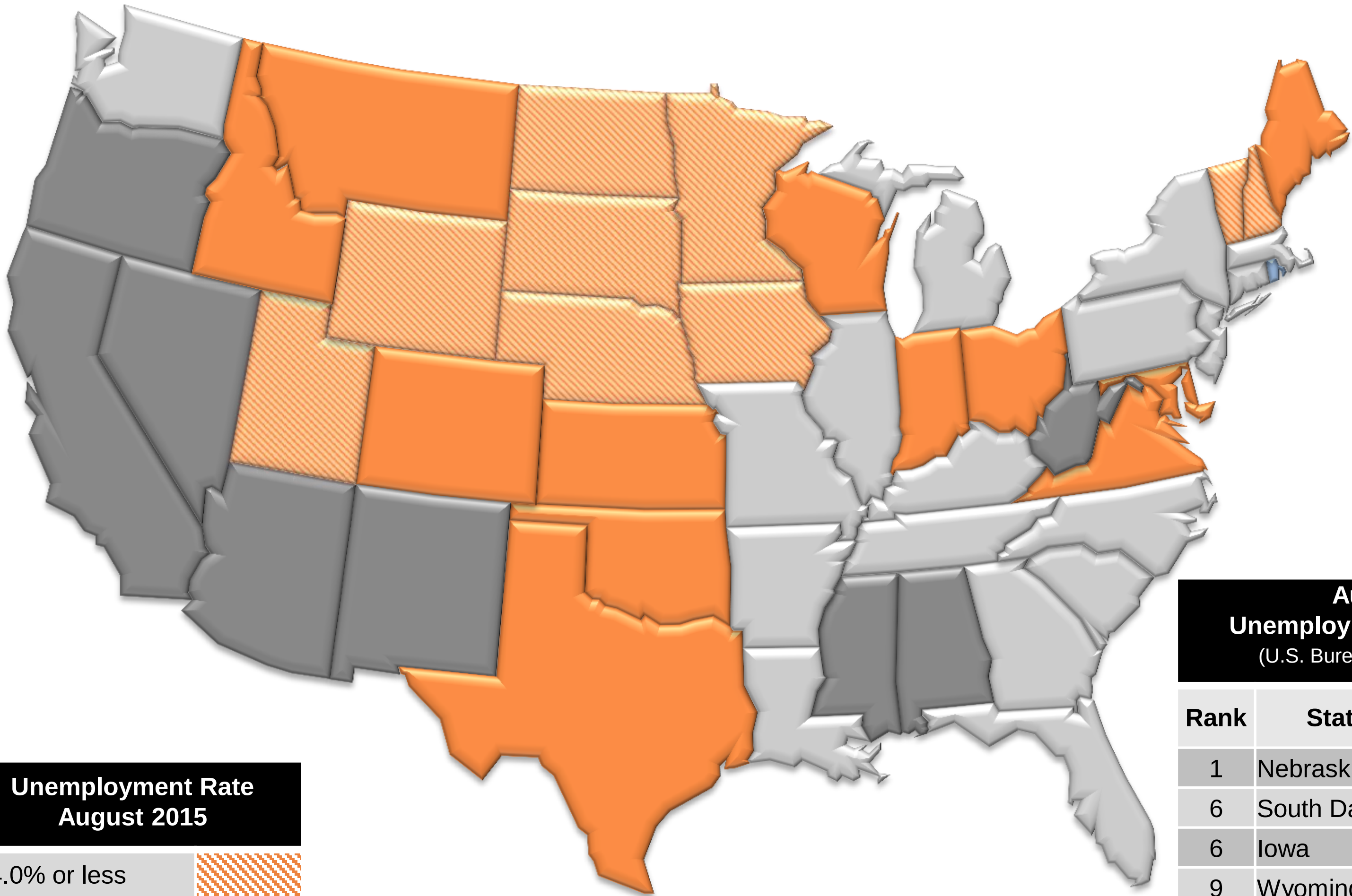
- Distributes natural gas to approximately 586,100** customers
- Operations include Black Hills Energy (CO, IA, NE and KS) and gas operations of Cheyenne Light*** (WY)
- Properties in northeastern and northwestern Wyoming are a subsidiary and division of Cheyenne Light, respectively, DBA Black Hills Energy
- Includes 1,142 miles of intrastate gas transmission pipelines and 21,956 miles of gas distribution mains and service lines
- Provides contract appliance repair service to approximately 63,000 customers through Service Guard Program in CO, IA, KS and NE

• Information from 2014 Form 10-K, unless otherwise noted

** Includes customers from the 2015 acquisitions of Energy West and MGTC in Wyoming

*** Financial results for our Wyoming natural gas properties are reported under our electric utilities

Regional Unemployment



Unemployment Rate August 2015	
4.0% or less	
4.1%- 5.0%	
5.1% - 6.0%	
> 6.0%	

August 2015 Unemployment Rates by State
(U.S. Bureau of Labor Statistics)

Rank	State	2015 Rate	2014 Rate
1	Nebraska	2.8	3.6
6	South Dakota	3.7	3.6
6	Iowa	3.7	4.5
9	Wyoming	4.0	4.6
11	Montana	4.1	4.7
13	Colorado	4.2	5.1
18	Kansas	4.6	4.9

Utility Capital Investment Drives Growth

PROFITABLE GROWTH

(in millions)	2011	2012	2013	2014	2015F	2016F	2017F
Generation	$85	$72	$130	$75	$62	$72	$32
Transmission	20	38	32	31	67	41	33
Distribution	44	44	48	87	49	60	44
Other	24	13	12	0	51	52	25
Subtotal Electric Utilities	173	167	222	193	230	225	135
Gas Utilities	44	46	63	71	69	60	72
Cost of Service Gas						50	100
Total Utilities*	217	213	285	264	299	335	307
Rider Eligible - Electric Utilities**					$81	$73	$30
Rider Eligible - Gas Utilities**					$13	$24	$32

* Excludes SourceGas acquisition, Peak View wind project (see slide 33) and discontinued operations
** Rider eligible capital expenditures included in the subtotals above for electric and gas utilities; excludes cost of service gas
Note: differences due to rounding

Growing Utility Customers and Demand

PROFITABLE GROWTH

Grow customers and demand → Efficiency gains through capital investment → Invest for reliability and capacity → Stabilize fuel costs and provide for capital investment

Recent Acquisitions:
SourceGas
Energy West
MGTC

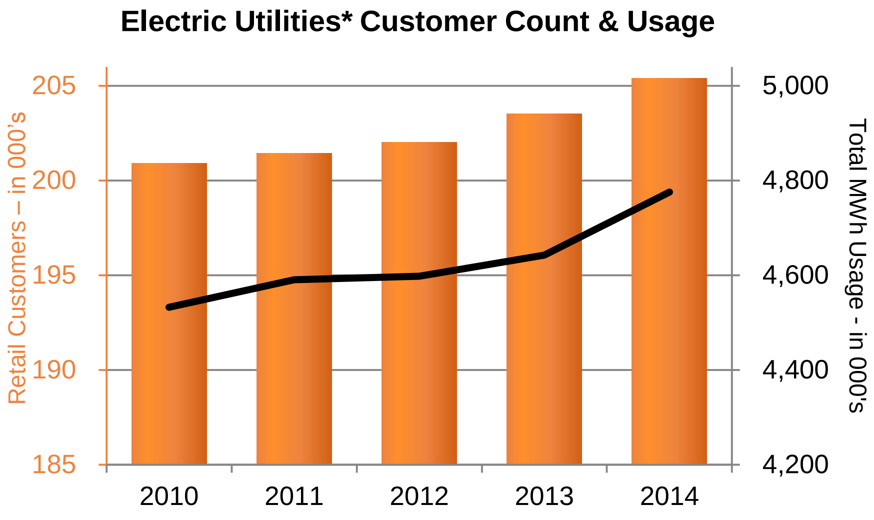
Organic Growth:
Horizon 1 projects (near-term such as customer additions, line extensions and conversions)
Horizon 2 projects (mid-term such as CNG stations, products and services)
Horizon 3 projects (long-term such as pipeline additions and acquisitions)

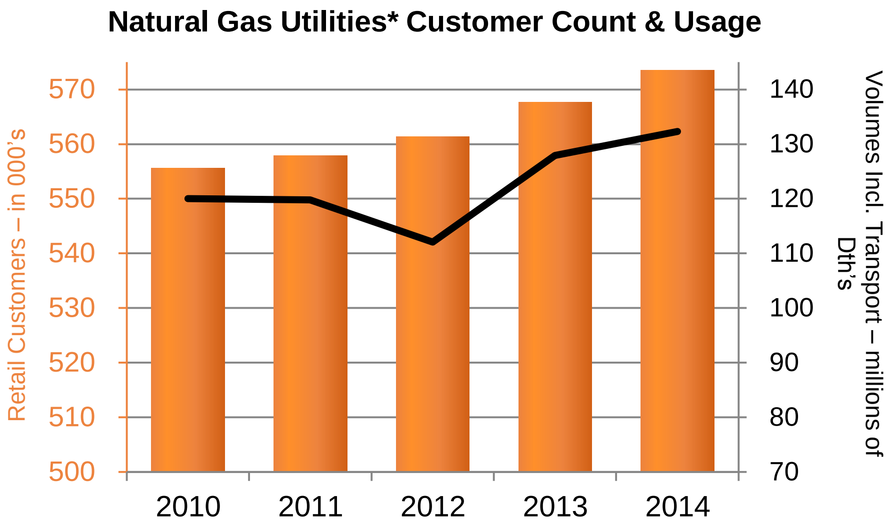
Organic growth defined as opportunities within and adjacent to our utility service territories; future progress will be measured through Residential Meter Equivalent (RME) – one RME equates to equivalent annual margin that a typical residential customer delivers

Customer Growth

Utility Customers and Usage

PROFITABLE GROWTH





* Cheyenne Light's gas customers and usage included in Natural Gas Utilities chart
Note: Volumes are actual and not weather normalized
Dth - dekatherm

SourceGas Acquisition Progressing

PROFITABLE GROWTH

Transaction and Purchase Price

- On July 12, Black Hills agreed to acquire SourceGas Holdings LLC for total consideration of $1.89 billion
  - $150 million of tax benefits lowers effective purchase price to $1.74 billion
  - Purchase price includes reimbursement of projected $200 million in capital expenditures
  - Transaction forecasts assumption of $720 million of debt

Fits Growth Strategy and Benefits Customers

- Creates stronger utility with enhanced operating scale; drives more efficient delivery of services and benefits customers

Increases Geographic and Regulatory Diversity

- Expands presence in CO, NE, and WY and adds new state of AR
- Increases customer base by 55% to more than 1.2 million electric and natural gas utility customers

Accretive to Earnings

- Meaningfully accretive to EPS in first calendar year after closing

PROFILABLE GROWTH

SourceGas Acquisition Progressing

Regulatory Approvals

- Received Hart-Scott-Rodino antitrust clearance on Aug. 18
- Filed joint applications for acquisition approval on Aug.10 with Arkansas Public Service Commission, Colorado Public Utilities Commission, Nebraska Public Service Commission and Wyoming Public Service Commission
  - Requested March 1 approval date in all four filings
- AR and NE have established procedural schedules – AR hearing scheduled for Jan. 7 and NE set for Jan. 12
- Discovery process with all four states ongoing
- On track to close transaction in first-half 2016

SourceGas Acquisition Progressing

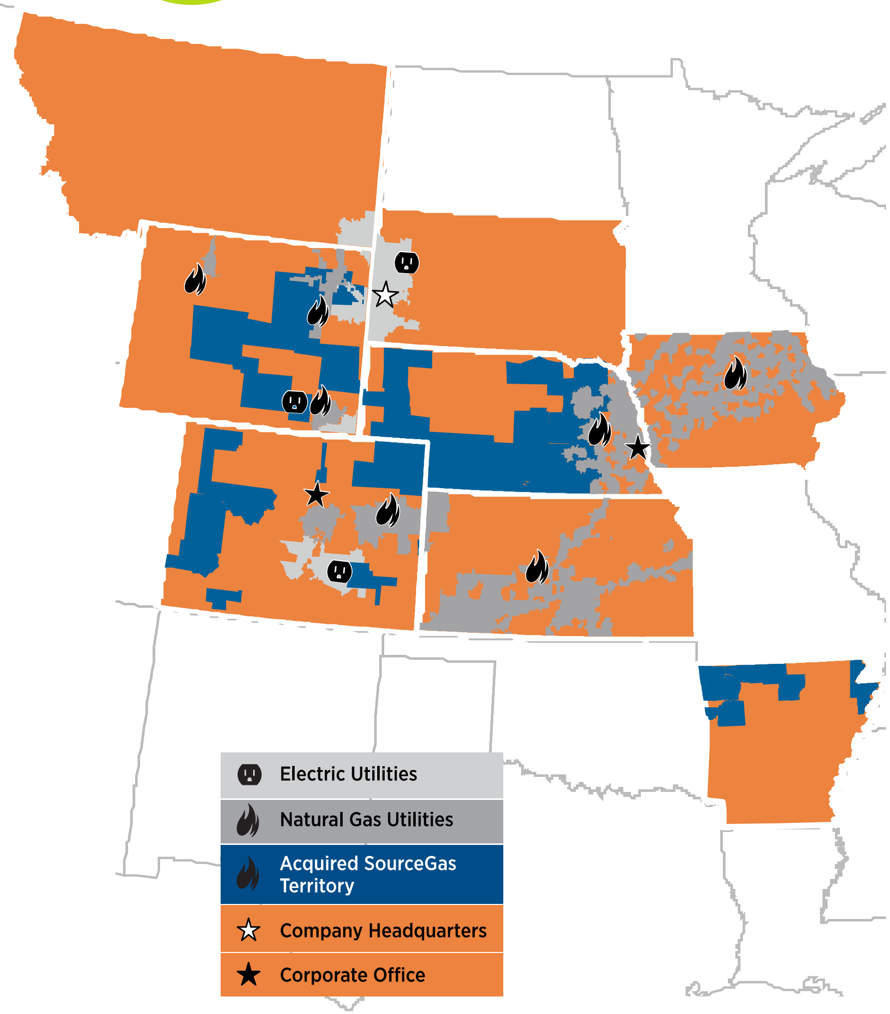
PROFITABLE GROWTH

Integration Activities Progressing

- Processes and systems already developed through 19 previous acquisitions
- Integration focuses on moving SourceGas' data and processes onto Black Hills' systems
- Overriding objective to provide uninterrupted, safe and reliable service
- Experienced leadership team leading integration efforts
- Variety of teams engaged in integration activities - focusing on customers and employees
- Employee communications ongoing – new website launched for updating all employees (SourceGas and Black Hills) on acquisition progress and integration

PROFITABLE GROWTH

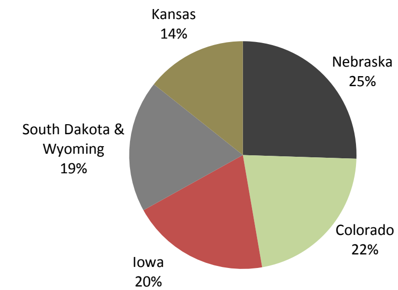
Pro Forma Combined Utility Overview



Black Hills Corporation

Total customers	**785,000**
States Served	**7**
	(CO, IA ,KS, MT, NE, SD, WY)

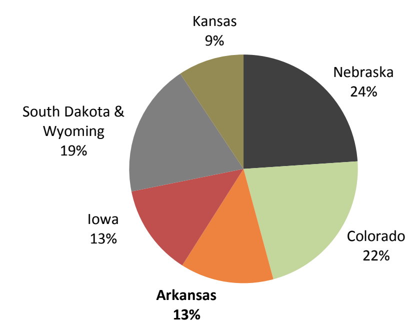
Total customers by region



Black Hills Corporation + SourceGas

Total customers	**1,210,000**
States Served	**8**
	(AR, CO, IA ,KS, MT, NE, SD, WY)

Total customers by region



Source: Company data.
Note: The map includes only Black Hills' electric and gas utility assets; the Company reports its Wyoming gas utility operations under Cheyenne Light

SourceGas Growth Opportunities

PROFITABLE GROWTH

Favorable economic and demographic drivers in service territories

- Over $600 million of long-term pipeline safety and integrity investment opportunities
- 2% annual customer growth expected
  - Solid residential and commercial growth - SourceGas forecasts adding approximately 7,200 net meters or 11,300 Residential Margin Equivalents annually
  - Fuel conversions supported by innovative and effective programs for residential, agricultural and poultry customers
- “Main extension” tariffs in all four states provide system expansion opportunities
- Pipeline and storage investment opportunities
- Future cost of service gas program potential

PROFITABLE GROWTH

SourceGas Regulatory Overview

Constructive Regulatory Environments

Gas Utility Jurisdiction	Cost Recovery Mechanisms						
	Forward test year methodology	Expedited rate case option / interim rates	Integrity management (infrastructure) rider	Purchased gas adjustment clause	Appropriate customer charge and tiered usage rates	Weather normalization adjustment	Revenue decoupling
Arkansas	☑	☑	☑	☑		☑	☑
Colorado	☑	☑		☑	☑		
Nebraska	☑	☑	☑	☑	☑		
Wyoming	☑			☑	☑		☑
Rocky Mountain Natural Gas (1)	☑	☑	☑	NA	NA	NA	NA

<u>Legend:</u>
☑ Currently in place

(1) Rocky Mountain Natural Gas, an intrastate natural gas pipeline

BETTER EVERY DAY

Growing by Gaining Efficiency

Grow customers and demand → Efficiency gains through capital investment → Invest for reliability and capacity → Stabilize fuel costs and provide for capital investment

Technology investments

Technology integration

progress as of June 30, 2015

Internal Systems

Customer Experience

- Mobile-Friendly Website
- Energy Use Profile
- eBill
- New Bill Format
- QR Code
- Customer Notification
- New Interactive Voice Response
- Company blog
- Payment Kiosk (CLFP)
- Free Web EFT payment
- Enhanced customer feedback platform
- Customer profile options
- Customer Dashboard
- Self-Directed Apps

15% CUSTOMERS CURRENTLY ENROLLED IN eBILL

53% PAYMENTS RECEIVED ELECTRONICALLY

Energy Grid

- AMI/AMR
- Remote connect/ disconnect
- Outage management
- Reliability Center
- Top quartile reliability
- Automation & Detection

↓90% ESTIMATED MANUAL METER READS (progress since Jan. 2010)

Field Operations

- Operations Order Capture
- iPad Deployment
- GPS Trucks (electric)
- Dispatching (FSO)
- Work and Asset Management
- Mapping

↑37% REMOTE CONNECT/DISCONNECT

↓97% TRUCK DEPLOYMENTS

(progress since Jan. 2011)

VALUED SERVICE

Growing by Serving Customer Needs

Grow customers and demand → Efficiency gains through capital investment → **Invest for reliability and capacity** → Stabilize fuel costs and provide for capital investment

Transmission, distribution, and generation

Black Hills Power - 144-mile, $54 million electric transmission line
Cheyenne Light, Fuel & Power – data center load growth and related utility investment
Colorado Electric - 40 MW, $65 million combustion turbine being built at Pueblo Airport complex
Colorado Electric - 60 MW, $109 million Peak View wind project, including transmission

Resource Planning Update

VALUED SERVICE

Colorado Electric

- 40 MW, $65 million natural gas-fired combustion turbine under construction at Pueblo Airport Generating Station
  - Replacement for retired W.N. Clark plant
  - Commercial operation in fourth quarter 2016
- 60 MW, $109 million Peak View wind project
  - Certificate of Public Convenience and Necessity settlement agreement filed Sept. 24; expect Colorado Public Utilities Commission deliberations on settlement agreement in Oct. and final order in Nov. 2015
  - Project to be purchased from developer; total investment including interconnection and AFUDC expected to be approximately $109 million
  - Commercial operation in fourth-quarter 2016
- CO PUC approved extension of filing date for next Electric Resource Plan to 2016 due to EPA release of final Clean Power Plan

VALUED SERVICE

Resource Planning Update

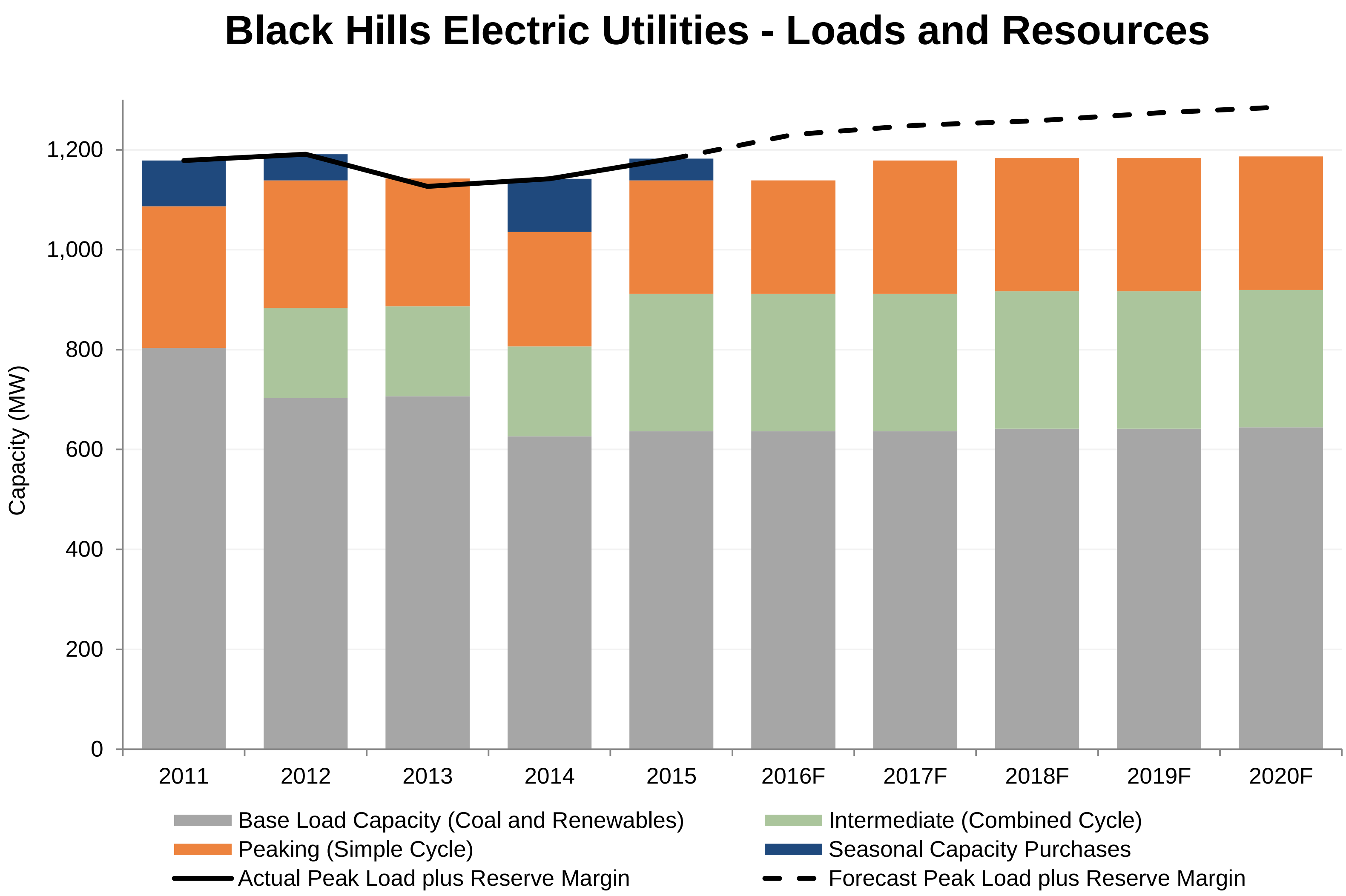
Cheyenne Light, Fuel and Power

Microsoft load growth

- First 35 MWs of load served under existing Industrial Contract Services Tariff
- Load in excess of 35MW served under proposed Large Power Contract Service Agreement tariff - filed Oct. 1, 2015 with a proposed effective date of Jan. 1, 2016
  - Includes microgrid management fee representing a return to BHC
  - Substantial additional load growth expected over next 10 years
    - Additional $250 million investment by Microsoft, with $750 million total investment in data center facilities by year-end 2017

Resource Planning Update

VALUED SERVICE



VALUED SERVICE

Optimizing Regulatory Recovery

Electric Utility Jurisdiction	Cost Recovery Mechanisms							
	Environmental Cost	DSM/ Energy Efficiency	Trans-mission	Fuel Cost	Trans-mission Cap-Ex	Purchased Power	Fixed Cost Recovery*	Financing Cost Rider
BHP - South Dakota	☑	☑	☑	☑	☑	☑		
BHP - Wyoming		☑	☑	☑		☑		
BHP - Montana				☑		☑		
BHP - FERC					☑			
CLFP - Electric Customers		☑	☑	☑		☑		
CLFP - Gas Customers		☑		☑[1]			52%	
BHE – CO Electric		☑	☑	☑	☑	☑		☑

Gas Utility Jurisdiction	Cost Recovery Mechanisms						
	DSM/ Energy Efficiency	Capital Additions	Bad Debt	Weather Normal	Pension Recovery	Fuel Cost	Fixed Cost Recovery*
BHE – CO Gas	☑					☑	47%
BHE – IA Gas	☑	☑				☑	70%
BHE – KS Gas		☑	☑	☑	☑	☑	64%
BHE – NE Gas		☑	☑			☑	55%

Legend:
☑ Commission approved cost adjustment
☐ Pursuing

* Residential customers
[1] Includes BH Energy - Wyoming

VALUED SERVICE PROFITABLE GROWTH

Growing by Investment in Fuels

1. Grow customers and demand
2. Efficiency gains through capital investment
3. Invest for reliability and capacity
4. Stabilize fuel costs and provide for capital investment

Cost of Service Gas

Direct investment in natural gas reserves provides long-term price stability for customers, while providing opportunities for utility investment

Initiating Cost of Service Gas

- Submitted cost of service gas regulatory filings on Sept. 30 in IA, KS, NE, SD and WY
  - Plan to file in CO during Oct. 2015
- Seeking pre-determination of prudence based on financial model and business case
  - Non-utility affiliate will provide service for utilities
  - Leveraging 30-years of oil and gas expertise to benefit customers
- COSG program's all-in cost compares well against the weighted average all-in cost of natural gas for utilities
- Program is a win-win for customers and shareholders alike

Cost of Service Gas - Regulatory Model

VALUED SERVICE PROFITABLE GROWTH

Wells

- **Term**
  Life of wells acquired or drilled on the properties, through abandonment and reclamation for each well
- **Drilling plan**
  Seeking stable production levels to support utilities' needs over 20 years; review in years 5, 10 and 15 with option to extend in year 20

Future Additions

- **Producing Property or Drilling Reserves**
  Based on commission approved guidelines established when program is approved

Financial

- **Demand Target**
  Up to 50% of weather normalized annual firm demand
- **Cost of Debt**
  Weighted average cost of debt
- **Capital Structure**
  40% / 60% - Debt / Equity
- **Recovery Mechanism**
  In accordance with existing adjustment clauses PGA/ECA

COSG - cost of service gas
COSGCO - cost of service gas company; new company to be setup under BHUH
BHUH - Black Hills Utility Holdings
PGA - Purchased gas adjustment
ECA - Energy cost adjustment

Return

- **Allowed Return**
  Average of all gas and electric utility rate case ROE's for the previous year or 20 most recent if less than 20 over prior year
- **Lower Cost than Market Price**
  If COSG revenue requirement less than COSGCO market sales proceeds, BHUH keeps difference up to 1% additional ROE; excess credited to customers
- **Higher Cost than Market Price**
  If COSG revenue requirement more than COSGCO market sales proceeds, BHUH absorbs difference up to 1% of reduced ROE; excess charged to customers.

Oversight

- **Independent Evaluation**
  Third-party hydrocarbon and accounting monitors; costs paid through program; assessing in advance each property purchase and proposed drilling program; audit of reports

Regulation and Policy Precedence

Other utility customers have benefited from long-term price stability

North-Western

Implemented solution for 82,000 customers in Montana
37% of annual demand
50% target

Black Hills Energy

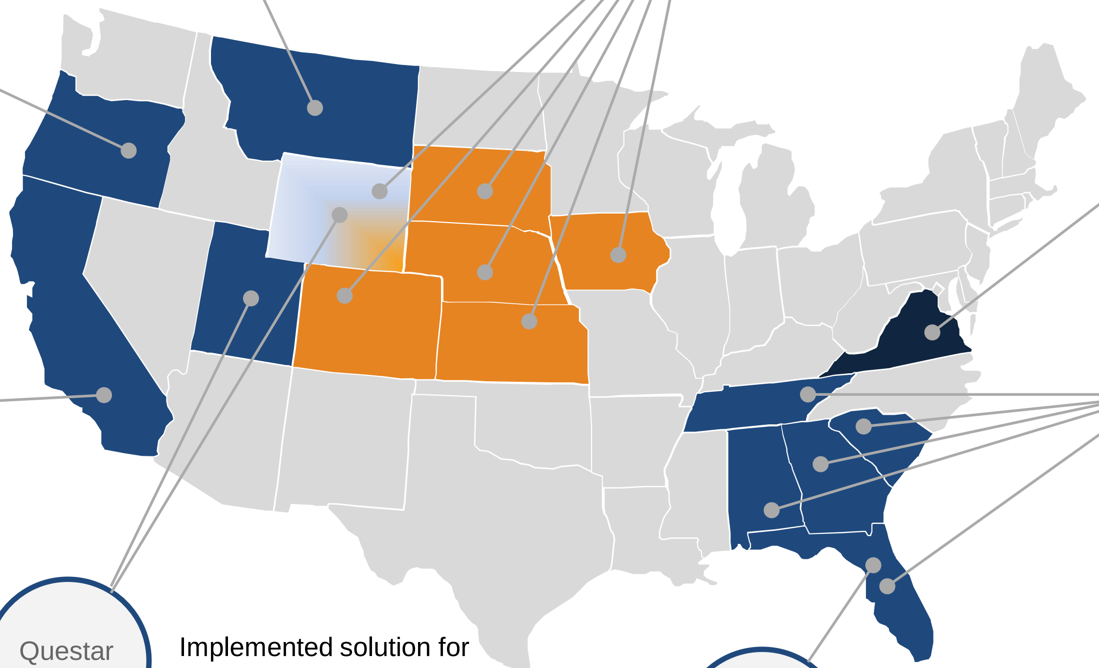
Evaluating opportunity to implement solution for 765,000 customers in Colorado, Iowa, Kansas, Nebraska, South Dakota and Wyoming

NW Natural Gas

Implemented solution for 600,000 customers in Oregon
10% of annual demand
25% recommended

NEW Legislative Enabler 2014

25% of annual demand



LA Water & Power

Implemented solution for 1.4 million customers in California.

Public Gas Partners

Implemented solution in Alabama, Florida, Georgia Tennessee and South Carolina

Questar Gas

Implemented solution for 939,000 customers in Utah and Wyoming
62% of annual demand

Florida Power & Light

Partnership with PetroQuest Energy in Woodford Shale; filed petition with Florida PSC in June 2014 seeking approval of transaction and guidelines for future projects
25% of annual demand by 2017
50% target

VALUED SERVICE PROFITABLE GROWTH

Natural Gas Demand by State

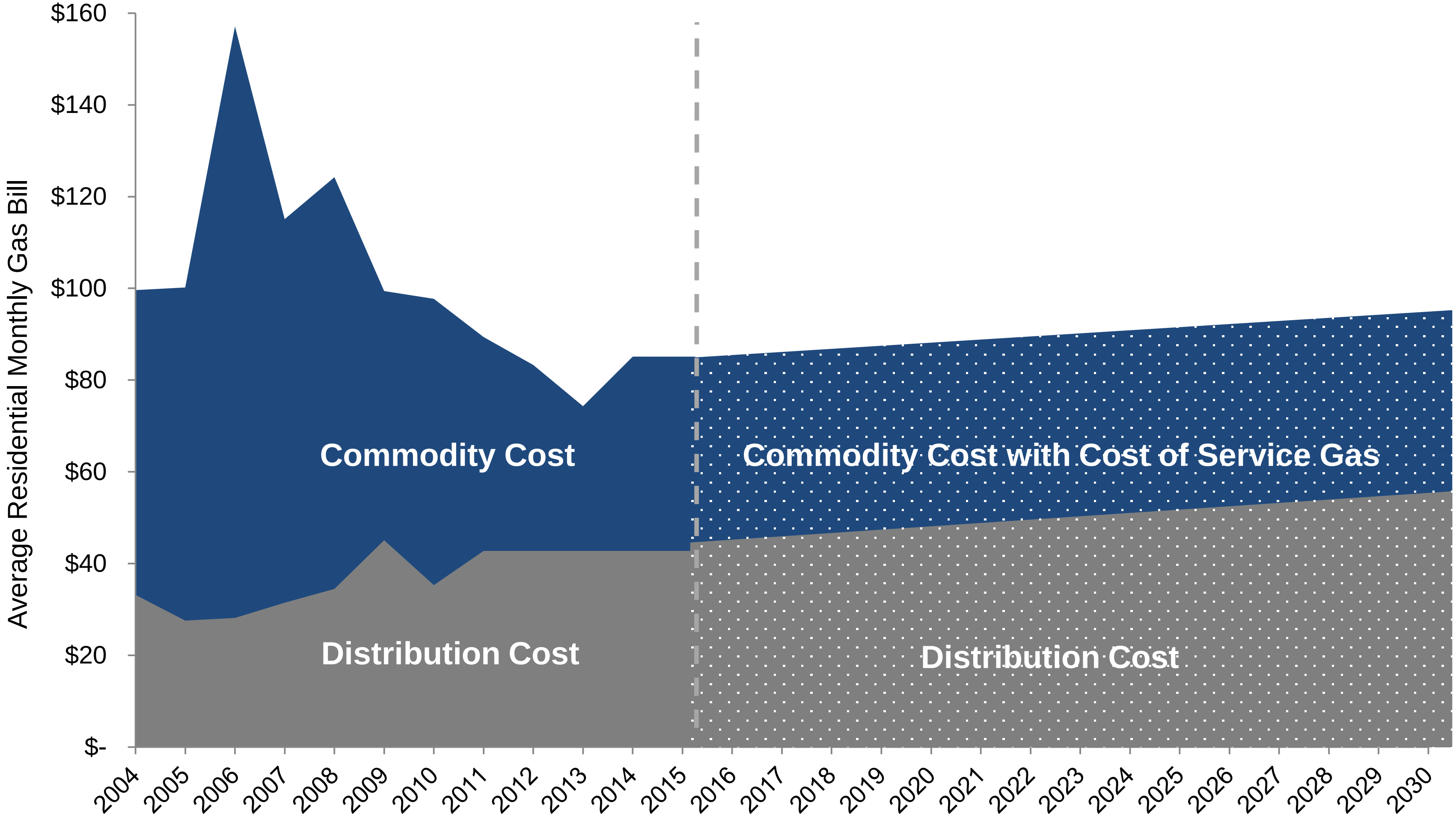
	Annual Demand* (Bcf)	50% Target	% of Total
Gas Utilities			
Iowa	20.00	10.00	26.4%
Nebraska	17.80	8.90	23.5%
Kansas	13.90	6.95	18.4%
Colorado	8.60	4.30	11.4%
Wyoming	4.50	2.25	5.9%
Power Generation			
Colorado	10.40	5.20	13.7%
Wyoming	0.50	0.25	0.7%
Total	**75.70**	**37.85**	**100%**

*2014 Actual

VALUED SERVICE PROFITABLE GROWTH

Enhanced Price Stability

Ownership of physical natural gas supplies provides greater long-term price stability for customers



Power Generation and Coal Mining

Mark Lux – Vice President & General Manager Power Delivery

Black Hills Corporation
Improving life with energy

Power Generation

- Ownership in two power generating facilities totaling 269 MW
  - Wygen I - 69 MW of a 90 MW coal-fired facility in Gillette, WY; 60 MW contracted to CLFP through Dec. 31, 2022
  - Pueblo Airport - 200 MW natural gas-fired facility in Pueblo, CO (co-located with regulated utility facility); contracted to Colorado Electric through Dec. 31, 2031
- Generation Services
  - Operating Agreement - 40 MW natural gas-fired facility with economy energy power purchase agreement
- Duplicating smaller plant approach facilitates latest technology
- Operate generation assets with same core management and support team
- Proven experience in planning, permitting, constructing and operating fossil fuel and renewable generation
- Prefer to expand existing generation sites for efficiency (brownfield development)
- Nearly all non-regulated generation capacity contracted to utility affiliates

Information from 2014 Form 10-K and updated for known changes

Power Generation Strategy

PROFITABLE GROWTH

- Sell power plant capacity under long-term tolling arrangements to affiliates, municipalities and other load serving electric utilities
- Sell economy energy purchase power agreements to other utilities
- Provide energy solutions through distributive energy resources

VALUED SERVICE

- Optimize plant performance
- Focus on smaller to mid-sized self-constructed power plant projects; utilize consistent technology to reduce construction and operating risk

BETTER EVERY DAY

- Provide generation operations services connected with ancillary services including generation dispatch and economy energy agreements
- Provide generation construction and other services to affiliate electric utilities
- Expand partnership opportunities

GREAT WORKPLACE

- Engage workforce with a focus on continuous improvement
- Be the safest energy company in the country

PROFITABLE GROWTH

Pueblo Airport Generating Station

Overview: New $65 million, 40 MW, natural gas-fired combustion turbine for Colorado Electric at existing Pueblo Airport Generating Station

Milestones:

- Received approval from Colorado Public Utility Commission Feb. 25, 2014
- Construction financing rider approved by commission Dec. 19, 2014
- Major equipment ordered Jan. 2015; construction started June 2015

Colorado Electric - 40 MW Combustion Turbine Project Capital Expenditure and Schedule Progress as of Sept. 30, 2015			
TCIR 0.0 as compared to industry average of 4.4			
Expenditures ($65 million)	Engineering Completed	Procurement Contracts Awarded	Construction Completed
$ 27.0 million	**76%**	**89%**	**21%**

PROFITABLE GROWTH

Peak View Generating Station

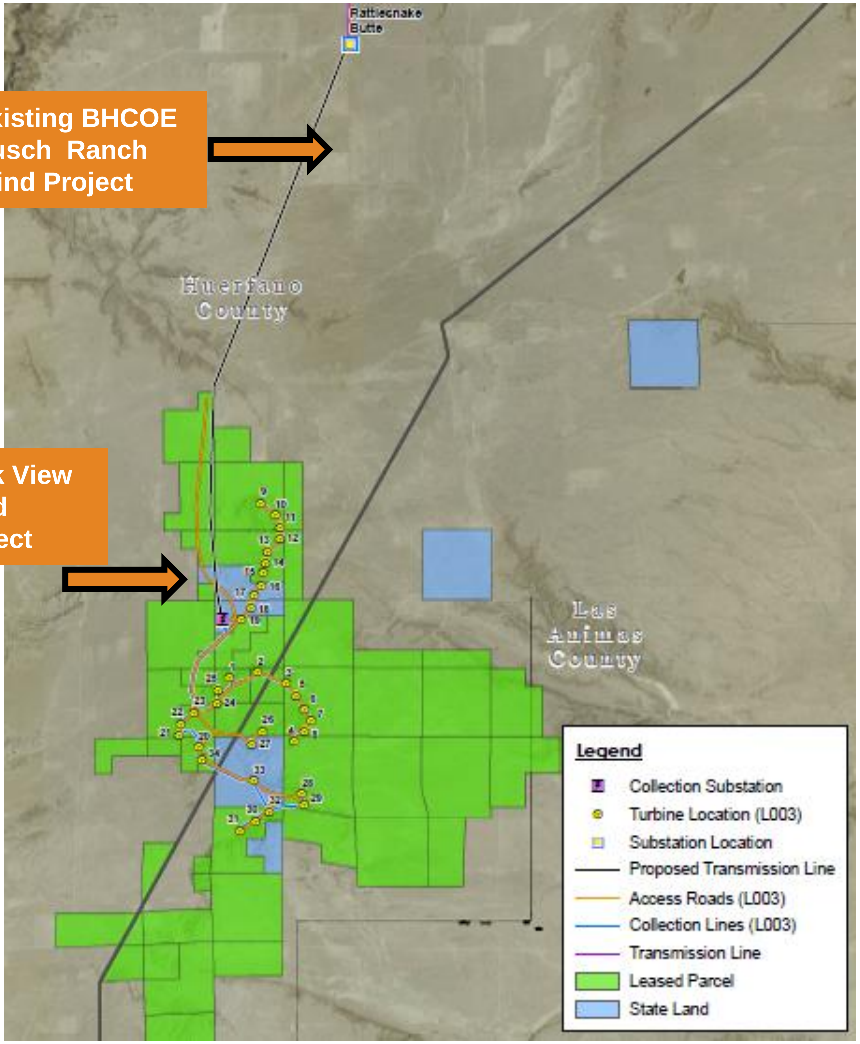
Overview: New $109 million, 60 MW wind generating project for Colorado Electric adjacent to existing Busch Ranch wind farm

Milestones:

- Executed Build Transfer Agreement with Invenergy and filed with Colorado Public Utility Commission Aug. 24
- Project settlement agreement filed with commission Sept. 24; advisor provided overview of settlement agreement Sept. 25
- Commission vacated hearings; expect deliberations in Oct. 2015 and order in Nov. 2015

Existing BHCOE Busch Ranch Wind Project

Peak View Wind Project



VALUED SERVICE

EPA Clean Power Plan

- Evaluating potential impacts of EPA Clean Power Plan issued Aug. 3, 2015
  - Significant changes from proposed rule to final rule
  - Each state must submit draft State Improvement Plan (SIP) Sept. 2016; may request two-year extension for final SIP
  - Three building blocks
    - Improved efficiency at power plants
    - Shift generation from coal units to natural gas units
    - Increase renewable generation
  - Compliance “glide path” with mandatory reductions beginning in 2022
    - “Mass-based” vs “Rate-based” state plan options
  - Regional approach encourages development of Mass-based emissions trading program

VALUED SERVICE

EPA Clean Power Plan

- EPA Clean Power Plan issued Aug. 3, 2015 (continued)
  - BHC engaged in each state's discussions and formulation of SIP
  - EPA clearly leaning toward Mass-based approach and emissions trading
- BHC compliance requirements will provide capital investment opportunities
  - Plant efficiency improvements (minimal, given BHC's new/efficient fleet of generating plants)
  - Increase utilization of existing combined-cycle natural gas plants (PAGS and CPGS) and develop new combined-cycle plants
  - Infrastructure and equipment investments to co-fire existing plants with mix of coal and natural gas
  - Increase renewable generation – wind and solar

VALUED SERVICE

EPA Clean Power Plan

Investment opportunity a function of emission reduction

Bottom 10 States for Emissions Reductions from Baseline

	2012 Baseline (lbs CO2/MWh)	2030 Goal (lbs CO2/MWh)	% Reduction in Emissions Rate
Nevada	1,102	855	22.41%
Mississippi	1,185	945	20.25%
Oregon	1,089	871	20.02%
New York	1,140	918	19.47%
Massachusetts	1,003	824	17.85%
Rhode Island	918	771	16.01%
California	963	828	14.02%
Maine	873	779	10.77%
Idaho	858	771	10.14%
Connecticut	846	786	7.09%

Top 10 States for Emissions Reductions from Baseline

	2012 Baseline (lbs CO2/MWh)	2030 Goal (lbs CO2/MWh)	% Reduction in Emissions Rate
South Dakota	2,229	1,167	**47.64%**
Montana	2,481	1,305	**47.40%**
North Dakota	2,368	1,305	44.89%
Wyoming	2,331	1,299	**44.27%**
Kansas	2,319	1,293	44.24%
Illinois	2,208	1,245	43.61%
Iowa	2,195	1,283	41.55%
Wisconsin	1,996	1,176	41.08%
Kentucky	2,166	1,286	40.63%
Colorado	1,973	1,174	**40.50%**

VALUED SERVICE

Wygen I Purchase Option Update

- Power purchase agreement between Cheyenne Light, Fuel & Power and Black Hills Wyoming (Power Generation) through Dec. 31, 2022
  - Contract provides strong profitability and contains escalation and government imposition clauses and a purchase option for CLFP
    - Purchase option allows CLF&P to purchase 76.5% ownership of 90 MW Wygen I coal-fired power plant through 2019 at $2.55 million per MW adjusted for capital additions and reduced by depreciation over 35 years starting Jan. 1, 2009
    - Uncertainty related to Clean Power Plan delays decision for CLFP to exercise purchase option

Coal Mining

- Serves as fuel supply to adjacent mine mouth electric power generation customers
- Approximately 48-year supply of low-sulfur Powder River Basin coal reserves at expected production levels
- Approximately 4.2 million tons of coal production forecasted in 2015
- Current mine plan sequence will reduce reclamation liability and optimize strip-ratio
- Cost-based pricing mechanism limits cash flow risk for tonnage delivered to affiliates

Information from 2014 Form 10-K

Coal Mining Strategy

PROFITABLE GROWTH

- Provide low-cost fuel supply to adjacent mine-mouth electric power plant customers while maintaining sufficient coal reserves to meet life-of-plant needs
- Maximize sale margins from existing contracts

VALUED SERVICE

- Provide low-cost, mine mouth fuel supply
- Maintain coal quality to meet contract requirements

BETTER EVERY DAY

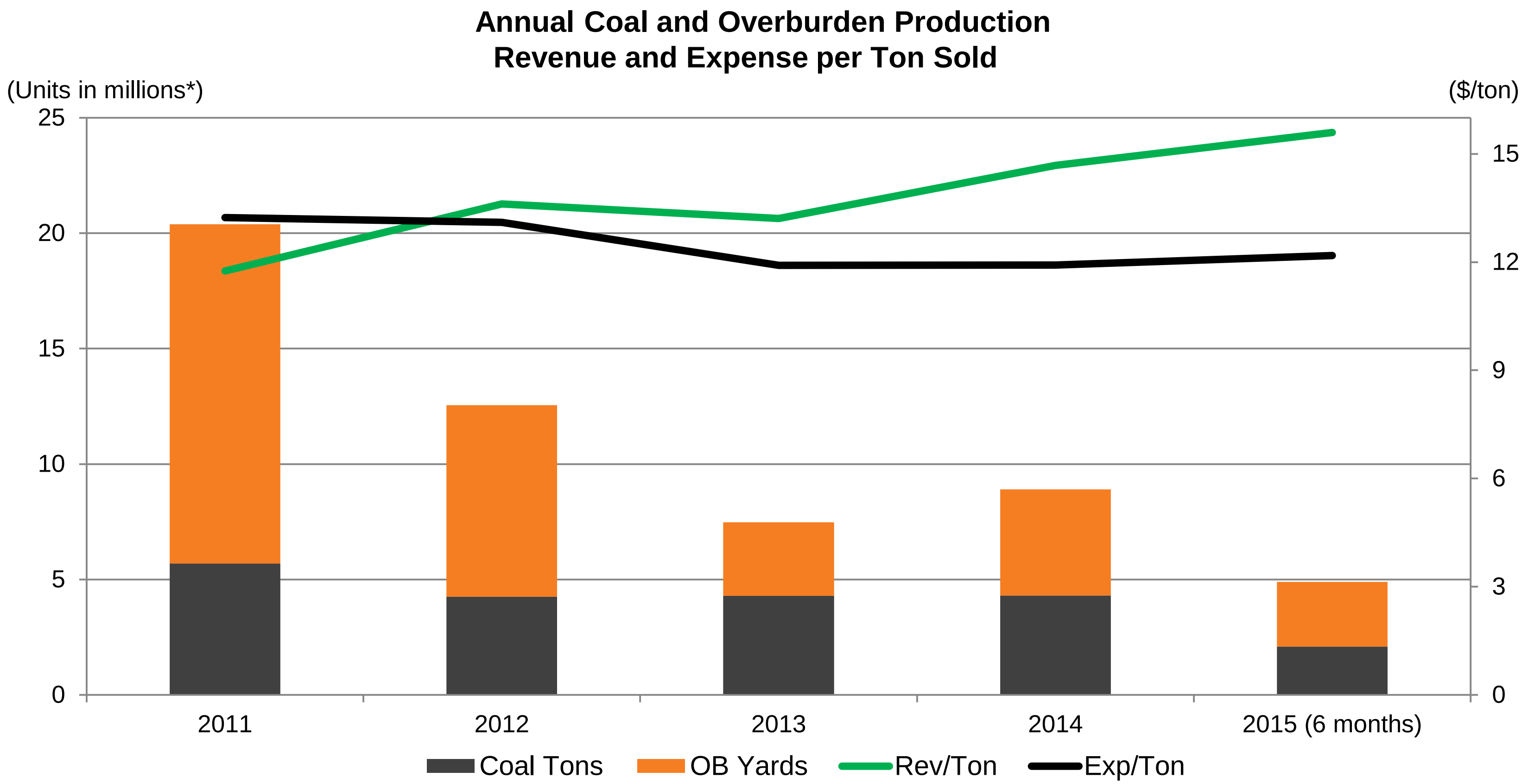
- Engage workforce with continuous improvement focus
- Achieve lower quartile MSHA citations compared to other PRB mines

GREAT WORKPLACE

- Become the safest energy company in the country

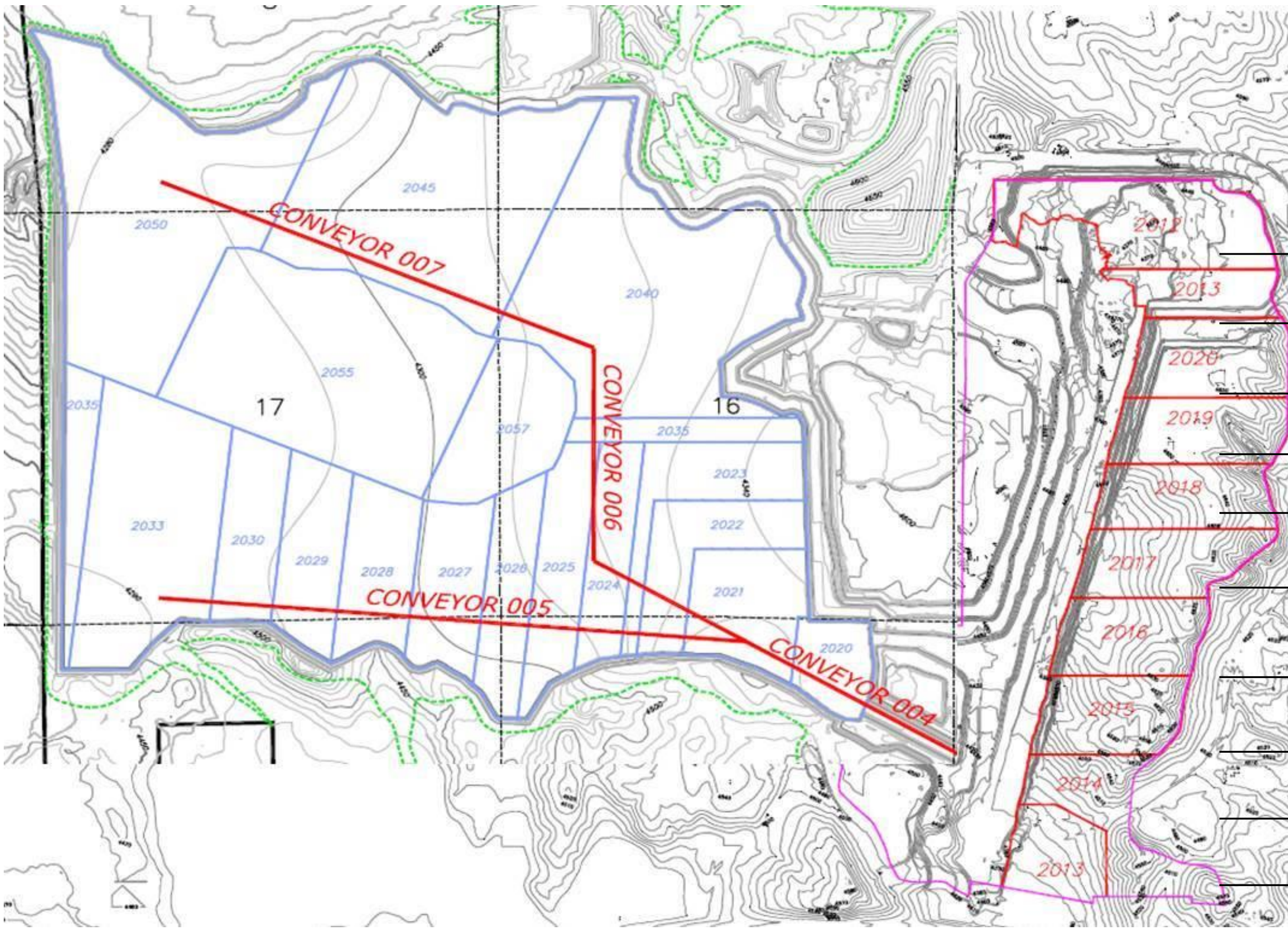
Operating Metrics

PROFITABLE GROWTH



* Units = tons sold plus cubic yards of overburden moved

Mine Sequence



Stripping Ratios*

2.1 to 1

2.1 to 1

2.1 to 1

1.5 to 1

1.6 to 1

2.2 to 1

2.1 to 1

1.8 to 1

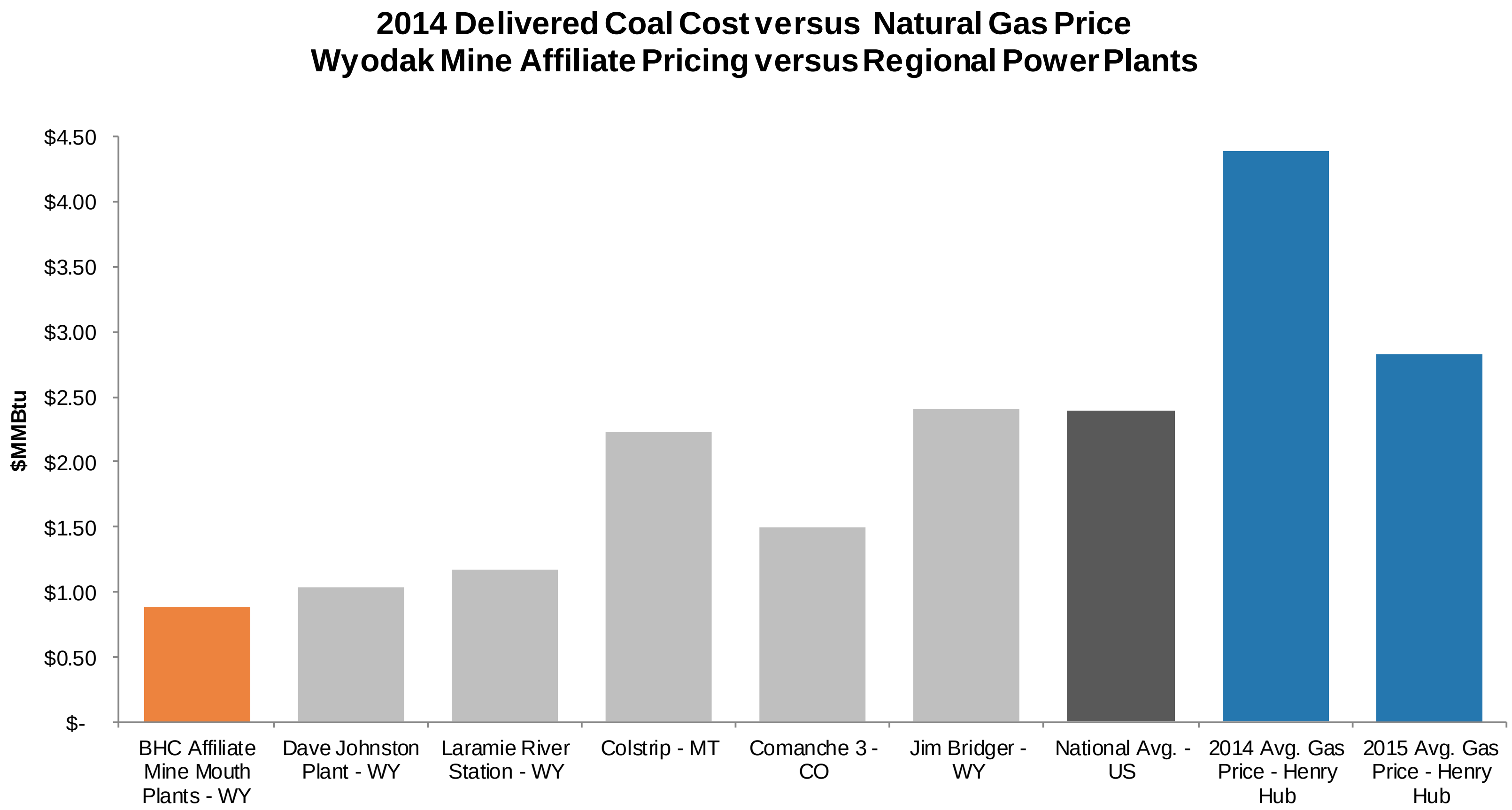
1.5 to 1

1.3 to 1

* The ratio of the volume of overburden required to be removed to the quantity of coal mined calculated as cubic yards / tons; years represent when coal will be mined

VALUED SERVICE

Competitive Delivered Fuel Cost



Information from SNL Financial

Oil and Gas

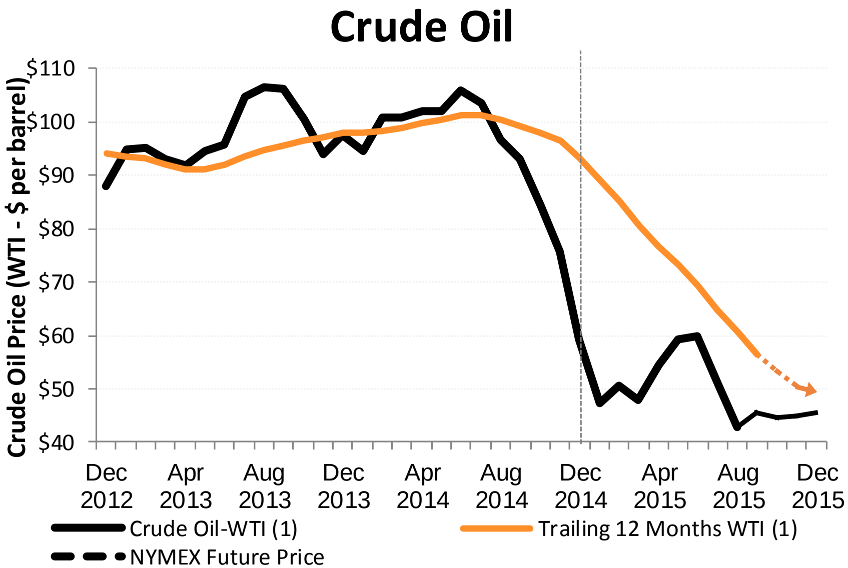
John Benton – Vice President & General Manager Oil & Gas

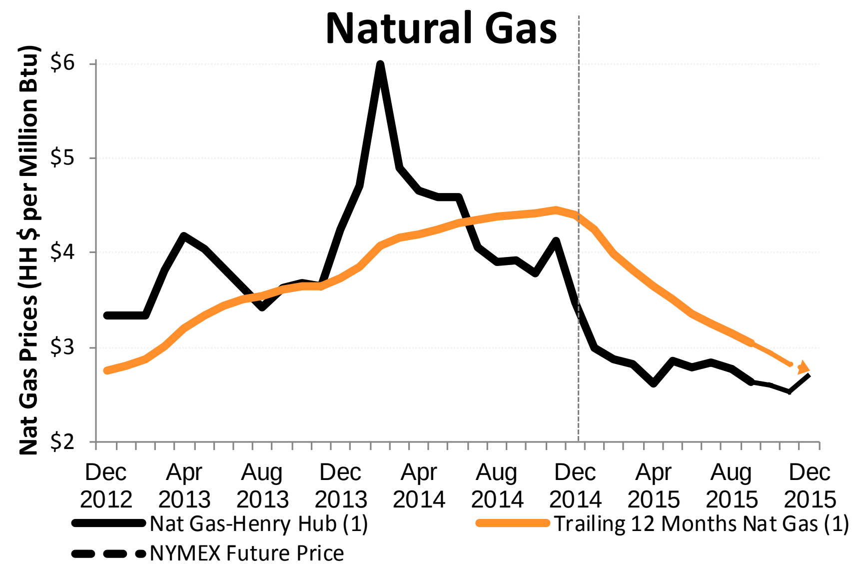
Black Hills Corporation
Improving life with energy

Oil and Gas Strategy Transition

- Sept. 2014 – balanced oil and gas program
- Jan. 2015 – gas focused program
  - Execute Piceance program - continue proving up asset
  - Reduce oil exploration capital
- July 2015 – transition to cost of service gas support
  - Execute Piceance program - target portion of asset for inclusion in COSG
  - Reduce future planned capital
    - Decreased 2016 planned capital spending from $122 million to $12 million
    - Decreased 2017 planned capital spending from $120 million to $15 million
  - Defer four Piceance completions, pending additional processing capacity
  - Reserve impairments reduce future depletion rate
  - Staff reductions reduce ongoing O&M expenses
  - Opportunistic monetization for non-core assets

Commodity Price Impacts on Ceiling Test





(1) Commodity prices represent average of monthly prices

Date	Oil & Gas Assets[2] *($MM)*	Impairment *($MM after tax)*	Crude Oil TTM[3]	Natural Gas TTM[3]
Dec 2014	$332	-	$94.99	$4.35
Mar 2015	$348	$14	$82.72	$3.88
Jun 2015	$275	$63	$71.68	$3.39
Sep 2015	TBD	TBD	$59.21	$3.06
Dec 2015	TBD	TBD	$48.31	$2.78

Impairments reduce future depletion rate

(2) Book value of total Oil and Gas assets
(3) Prices listed are average of the quoted NYMEX prices from the first day of each month from the previous 12 months (TTM=Trailing Twelve Months), as utilized in determining the ceiling test for full cost accounting; Dec. 2015 TTM prices are based on guidance assumptions

PROFITABLE GROWTH

Drilling Program

2014 Program

- Drilled and completed three Mancos appraisal wells in southern Piceance Basin
- Built out Piceance Mancos infrastructure
- Continued testing oil exploration wells
- Continued to identify and acquire oil resource potential

2015 Program

- Drilled ten additional Mancos appraisal wells in southern Piceance Basin
  - Completed six wells, deferred four wells due to limited plant processing capacity
- Drilled select oil appraisal wells

2016 Program

- Continue testing Piceance Mancos appraisal wells
- Complete evaluation of Piceance Mancos for cost of service gas program
- Preserve oil asset development optionality

PROFITABLE GROWTH

Southern Piceance Basin - Mancos Shale

2013-2015 Drilling Program Status

Piceance Mancos Well Status **As of: Sept. 30, 2015**

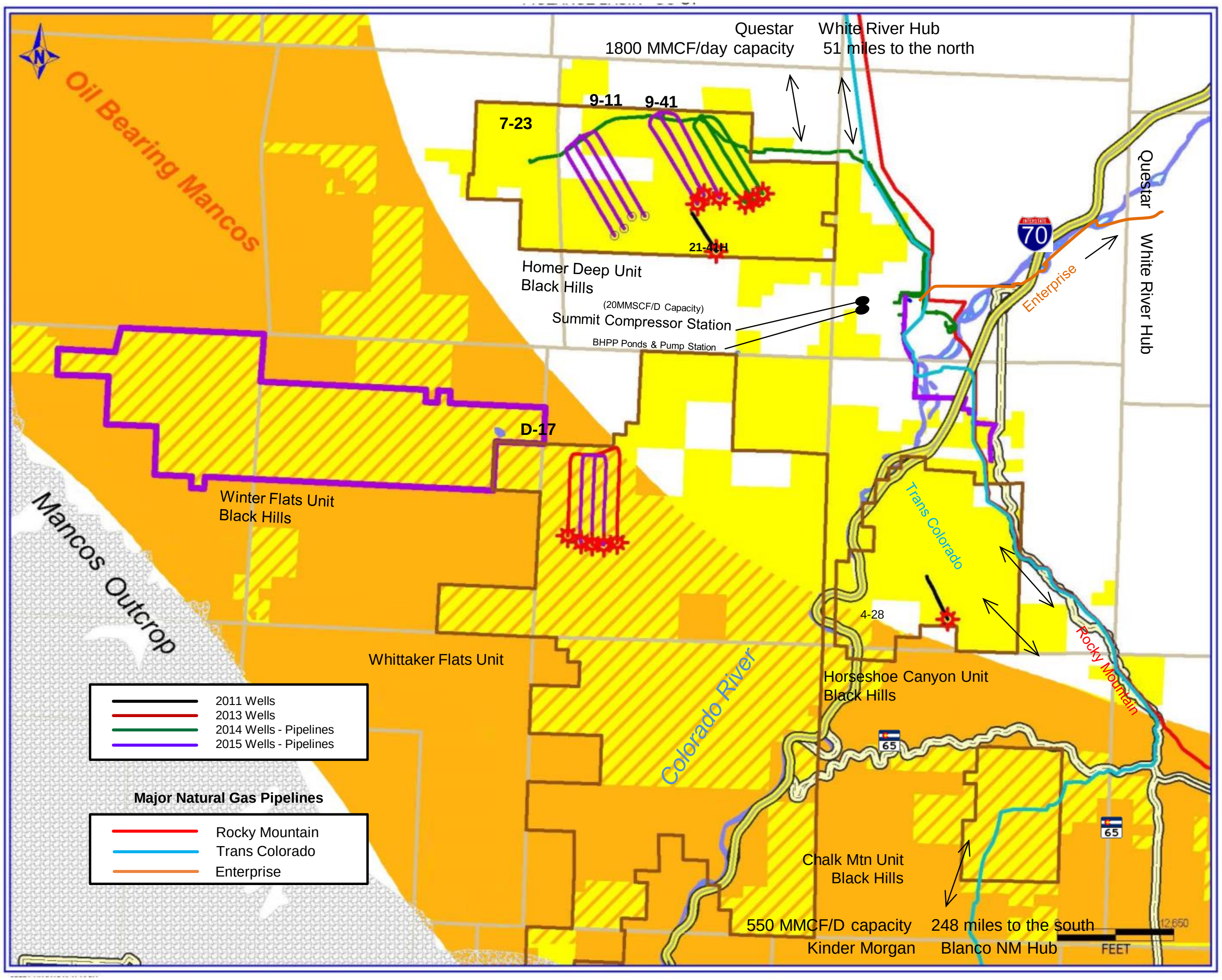
Well	Status	Date of First Production	Depth (feet)	Lateral Length (feet)	Frac Stages	Sand per Lateral ft (lbs)	Completed Well Cost ($MM)	Recoverable Reserves[1] (EUR, BCFE)	F&D Costs[2] ($/MCFE)	First 30-days' Production	
										Gas (MMCFD)	Condensate (BBLS/Day)
Homer Deep:											
9-41AH	Producing	Feb-2015	18,328	8,325	42	1,158	$15.8*	10.0*	$1.58*	6.0**	0.0
9-41BH	Producing	Feb-2015	17,886	9,910	50	1,556	$14.7*	10.0*	$1.47*	6.4**	0.0
9-41CH	Producing	Feb-2015	18,200	8,340	46	1,130	$15.6*	10.0*	$1.56*	6.7**	0.0
9-11AH	Fraced, Flowing to Sales	Aug-2015	18,851	9,766	49	1,364	$11.6			7.5**	0.0
9-11BH	Fraced, Flowing to Sales	Sep-2015	17,343	9,243	46	1,592	$11.8				
9-11CH	Fraced, Flowing to Sales	Sep-2015	17,310	8,303	46	1,365	$12.3				
7-23AH	Cased & Cemented	Q1-2017*	17,995	9,892							
7-23BH	Cased & Cemented	Q1-2017*	17,600	10,028							
7-23CH	Cased & Cemented	Q1-2017*	17,265	9,344							
7-23DH	Cased & Cemented	Q1-2017*	18,080	10,025							
Whittaker Flats:											
3C-20	Producing	Jan-2014	16,969	8,742	43	1,110	$12.5	7.7	$1.63*	6.1	52.9
3C-19	Producing	Dec-2013	15,350	8,125	40	1,160	$10.1	7.0	$1.44*	5.1	42.2
7C-20	Fracing well	Q4-2015*	15,618	8,912	45	1,907					
5C-20	Fraced, awaiting flowback	Q4-2015*	15,780	8,955	42	1,971					
1C-19	Fraced, awaiting flowback	Q4-2015*	15,512	8,652	39	2,034					

(1) Estimated ultimate recovery (EUR) - Estimation of 100% of the quantity of oil and gas that is potentially recoverable or already recovered under current economic conditions using existing production data to forecast future performance
(2) Defined as 100% of the completed well cost divided by Estimated Ultimate recovery (EUR) as defined above
* Estimated
** Production restricted due to processing plant capacity

PROFITABLE GROWTH

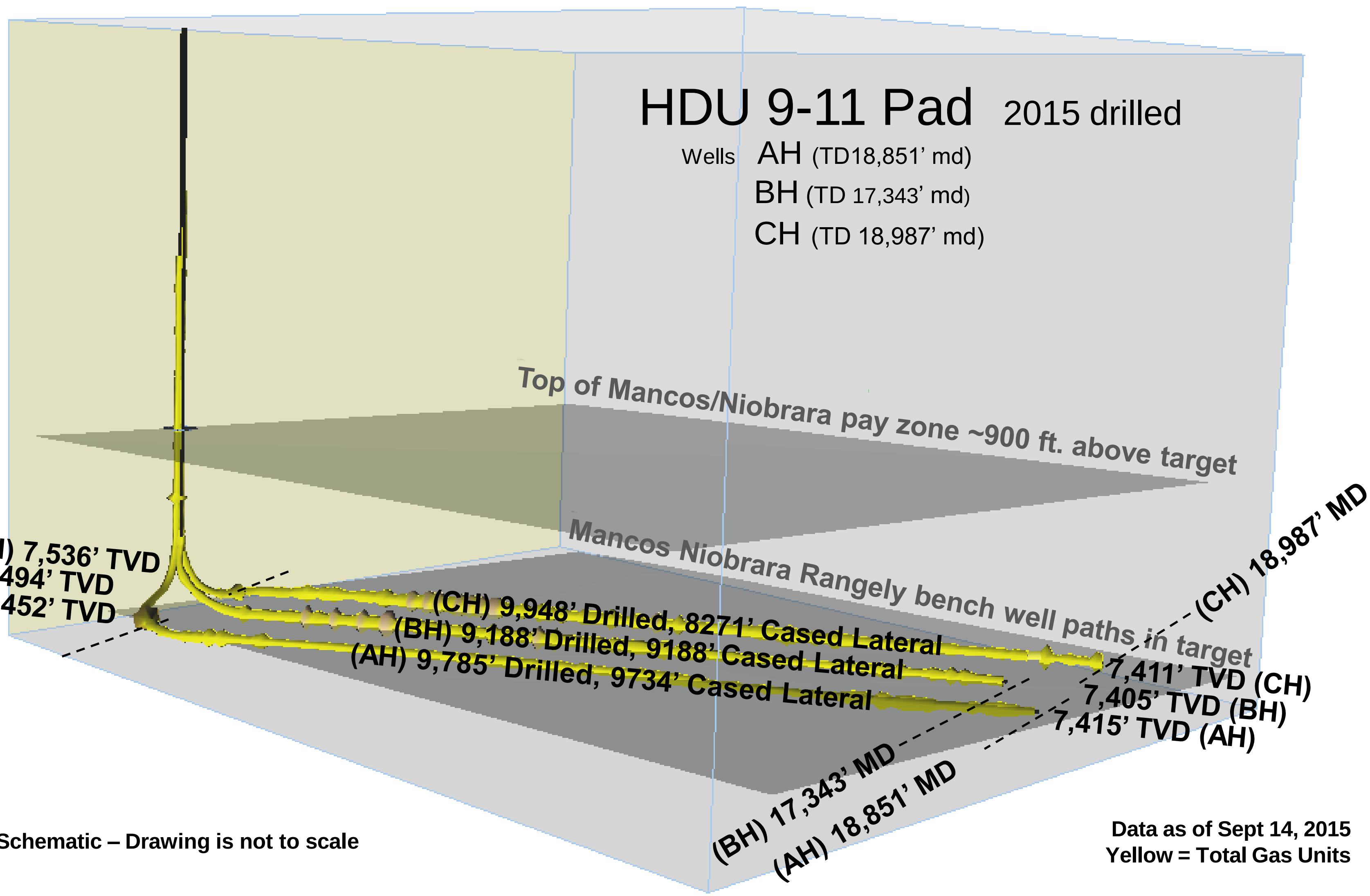
Southern Piceance Basin

Mancos Drilling Program 2013-2016



Southern Piceance Basin – Mancos Wells

PROFITABLE GROWTH

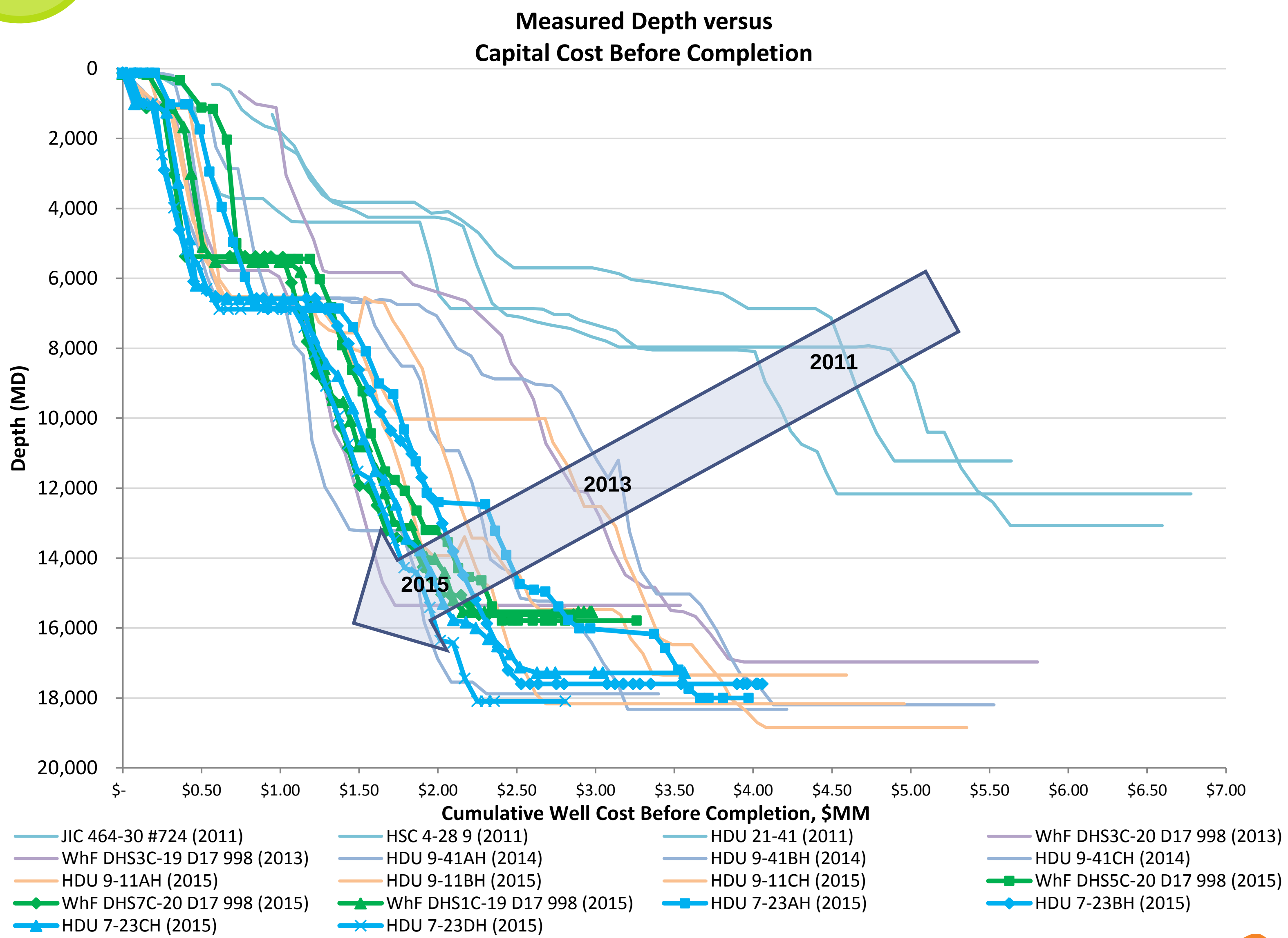


Schematic – Drawing is not to scale

Data as of Sept 14, 2015
Yellow = Total Gas Units

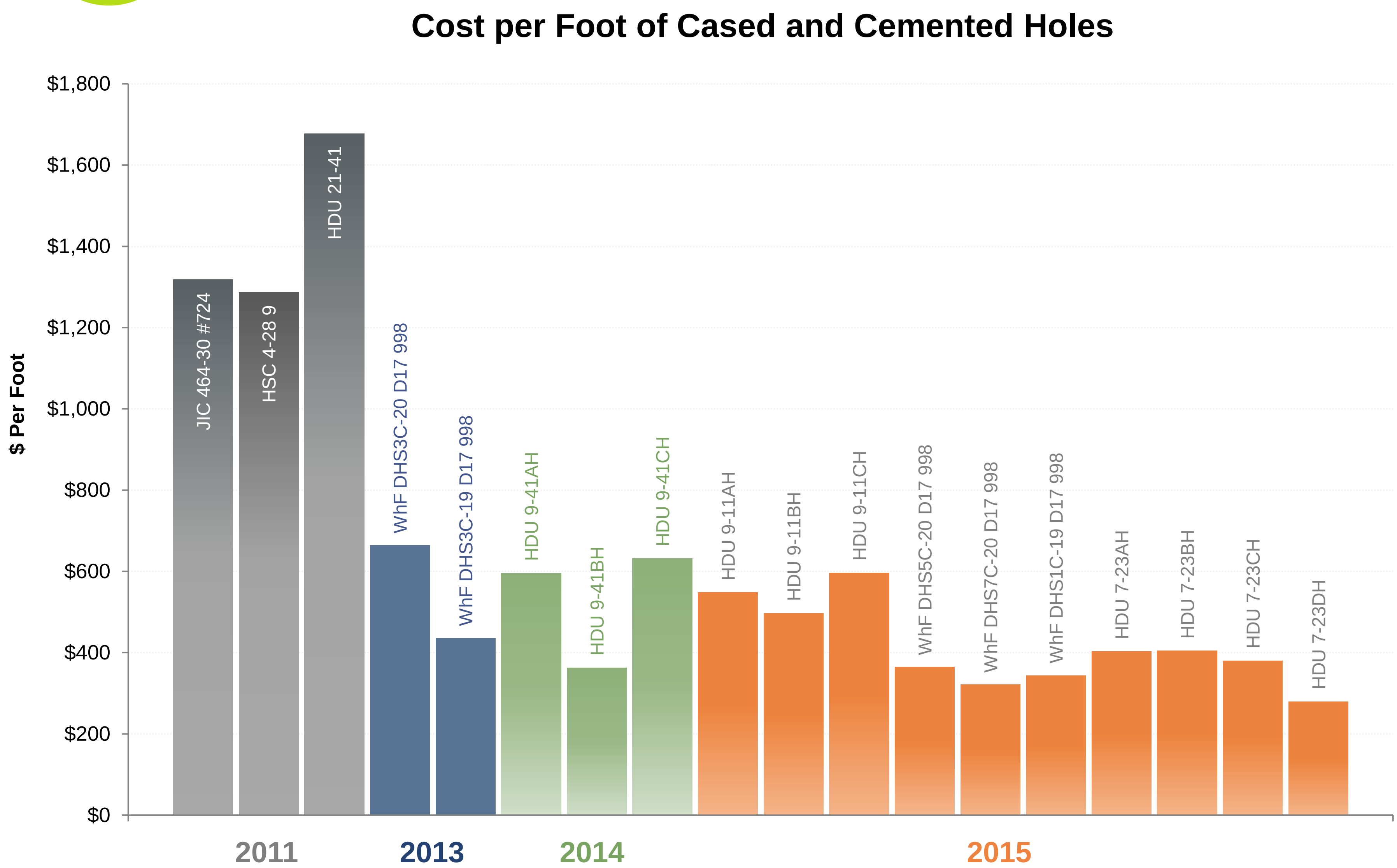
Mancos Shale - Well Optimization

PROFITABLE GROWTH



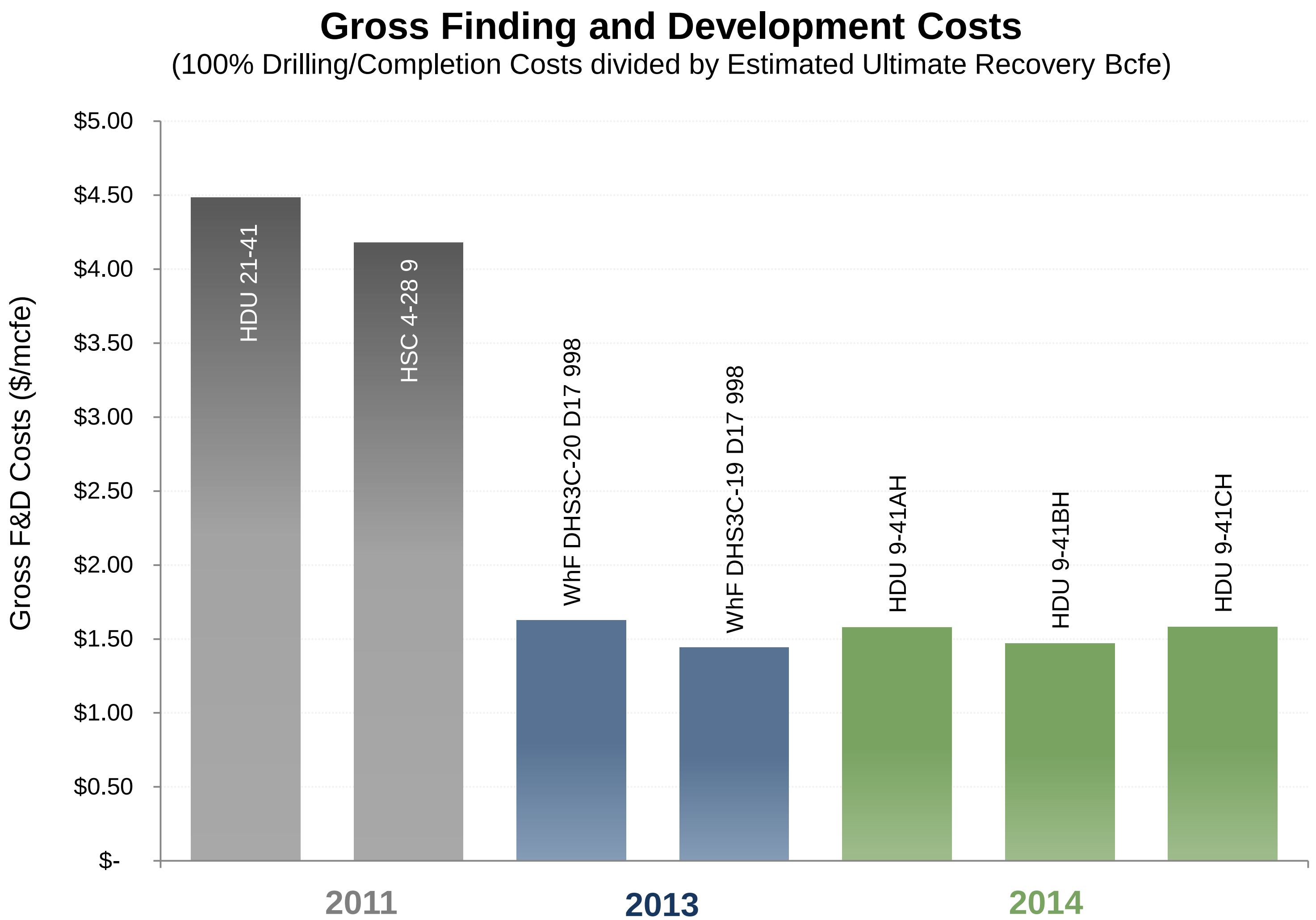
Mancos Shale - Well Optimization

PROFITABLE GROWTH



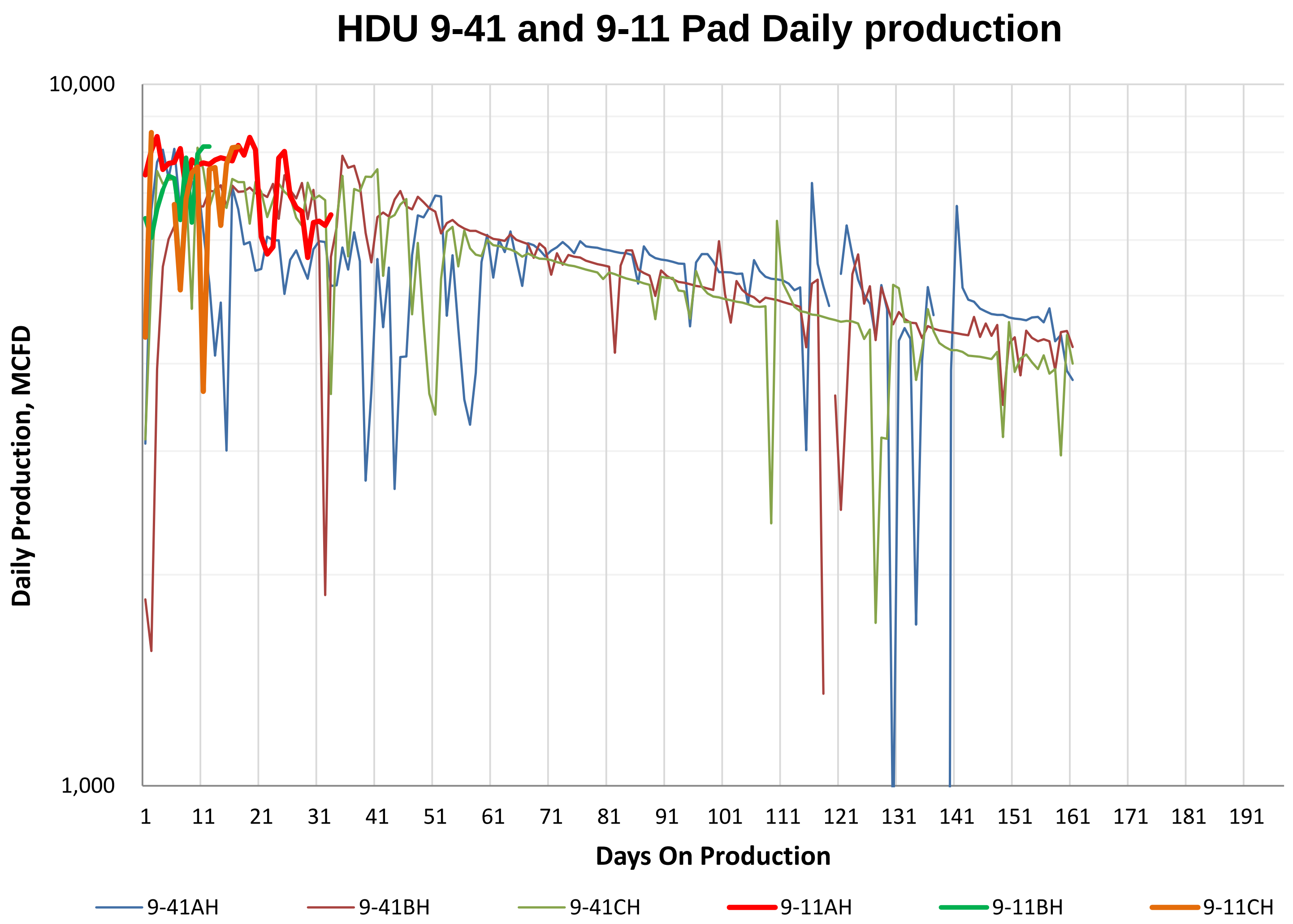
Mancos Shale - Well Optimization

PROFITABLE GROWTH



Southern Piceance Basin
Recent Mancos Wells Completions

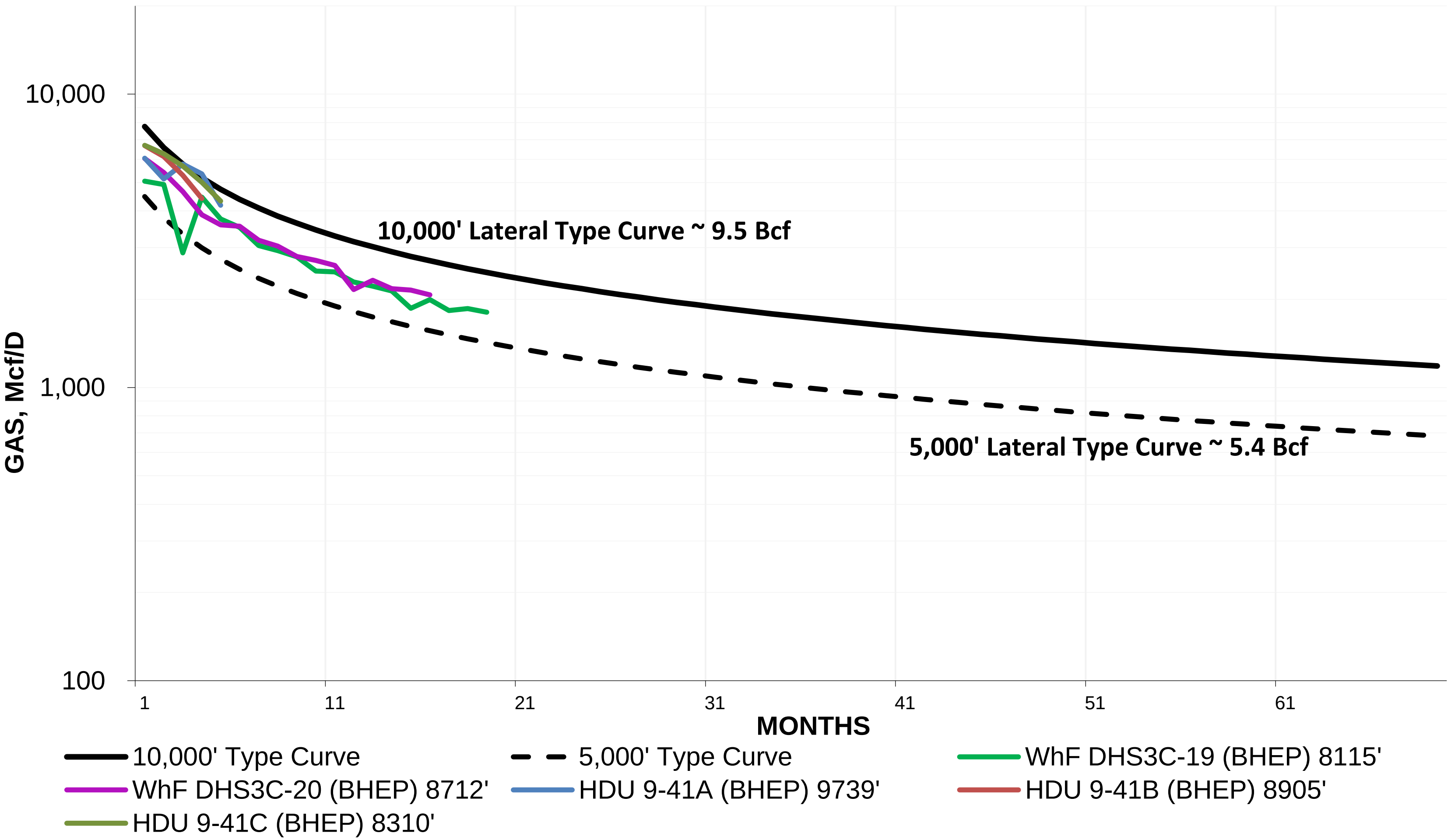
PROFITABLE GROWTH



PROFITABLE GROWTH

Southern Piceance Basin

Mancos Type Curves



PROFITABLE GROWTH

Oil and Gas Strategy

Creating Shareholder Value

- Execute current southern Piceance Basin program
  - Net resource potential – 2.2 to 4.4 TCFE
- Transition to cost of service gas program support
  - Target Piceance Mancos for inclusion in program
  - Program improvement supports inclusion
    - Reduced drilling and completion costs
    - Improved production and reserve performance
- Reduce capital
  - Eliminate projects that are uneconomic under current market conditions
    - Reduced 2016-2017 capital program from $242 million to $27 million
- Reduce staff
  - Reduced staff level 25%; reduces ongoing annual O&M expenses by $3.4 million
    - Retained capability to execute COSG program
- Monetize non-core assets

Financial Strategy

Rich Kinzley – Senior Vice President and CFO

Black Hills Corporation
Improving life with energy

Financial Strategy

Achieve top quartile total shareholder returns relative to our peer group for each rolling three-year period

Profitable Growth	Valued Service	Better Every Day	Great Workplace

- Prudently grow utility rate base for customer and shareholder benefit
- Deploy utility capital to reduce O&M expenses
- Acquire and effectively integrate utility customers
- Increase utility customer base through organic growth
- Leverage continuous improvement to improve cost structure
- Utilize power generation and coal assets to enhance electric utilities' overall performance
- Maintain strong capital structure with solid investment grade credit ratings
- Maintain track record of increasing dividends

Earnings Guidance and Assumptions

Black Hills raises its guidance for 2015 earnings, as adjusted*, to $2.90 to $3.10 per share from $2.80 to $3.00 per share. Assumptions include:

- Capital spending of $499 million, including oil and gas capital expenditures of $179 million;
- Normal operations and weather conditions within our utility service territories for the remainder of the year that impact customer usage, and planned construction, maintenance and/or capital investment projects;
- No significant unplanned outages at any of our power generation facilities;
- Full year oil and gas assumptions:
  - Oil and natural gas production in the range of 12.9 - 13.3 billion cubic feet equivalent;
  - Oil and natural gas annual average NYMEX prices of $2.78 per million British thermal units for natural gas and $48.31 per barrel for oil; production-weighted average well-head prices of $0.89 per MMBtu and $39.02 per Bbl of oil, and average hedged prices received of $1.59 per MMBtu and $59.07 per Bbl;
  - Oil and natural gas depletion expense in the range of $1.90 - $2.10 per thousand cubic feet equivalent;
- No equity financing in 2015 except for approximately $3 million from the dividend reinvestment program; and
- No significant acquisitions or divestitures for the remainder of 2015
- Excludes acquisition cost for the remainder of 2015

*Non-GAAP measure; see Appendix for reconciliation of Non-GAAP to GAAP

Colorado IPP – Evaluating Strategic Alternatives

- Company received multiple inquires over last couple of years regarding potential sale of long-term contracted assets, such as COIPP
- Evaluating the sale of up to 49.9% of COIPP
- 200 MW combined-cycle natural gas-fired generating facility contracted to Colorado Electric through 2031
- Potential buyers looking for yield relative to fixed income alternatives, including U.S. treasuries; potential buyers both strategics and financials
- Recent long-term contracted asset sales imply strong valuation
- Current NOL position for company reduces immediate tax impacts
- Sale proceeds would lower the amount of equity and debt needed to fund the SourceGas acquisition

Financing Update

SourceGas Financing Update

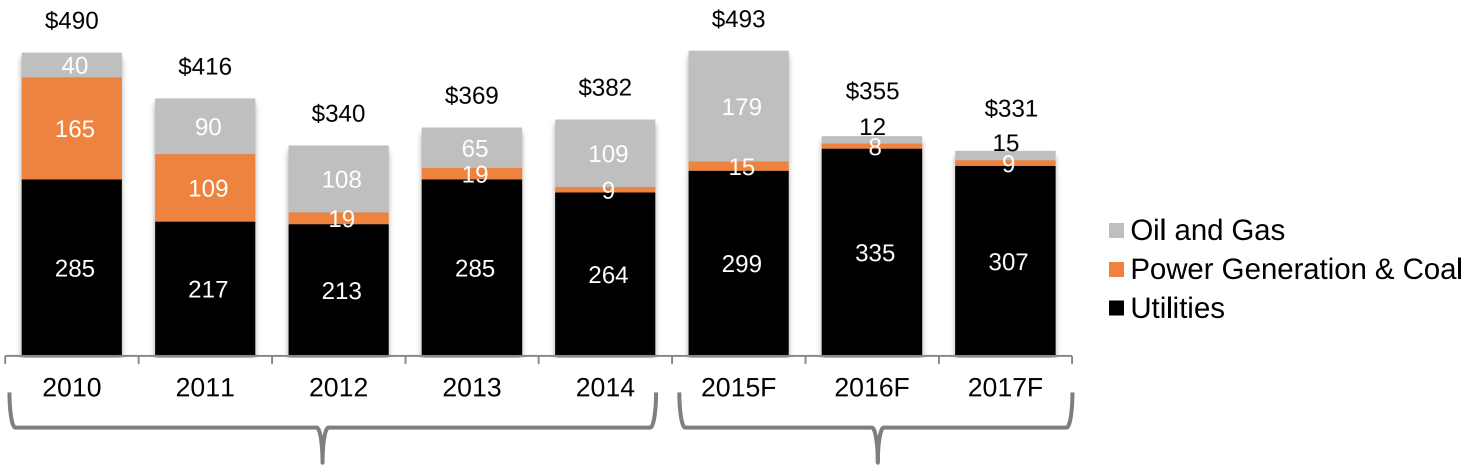
- Completed syndication of $1.17 billion bridge facility
- Plan to assume approximately $720 million of SourceGas debt
- Cash from potential asset sales and oil and gas capital reduction will reduce financing needs
  - Revised equity needs to $450 million to $600 million (from previously disclosed $575 - $675 million); includes $200 million to $300 million of unit mandatory convertibles
  - New debt issuance needs continue to be $450 million to $550 million

Other Financings

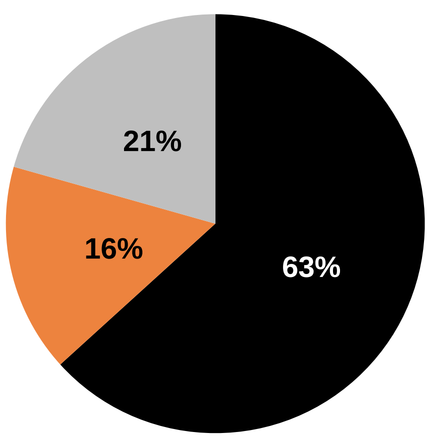
- Evaluating interest rate hedging for upcoming long-term debt financings in 2016 and 2017; on Oct. 2, hedged $250 million of 10-year treasury interest rate risk from now though Apr. 2017 for forecasted future financing
- Evaluating introduction of an "at-the-market" equity offering program
- Reviewing options to finance $109 million Peak View wind project, if approved by the Colorado PUC

PROFITABLE GROWTH

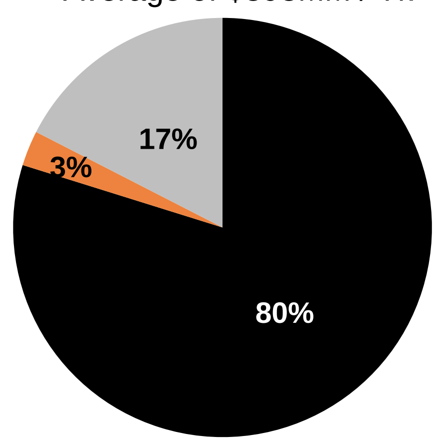
Capital Investment by Segment



2010 – 2014
Total Capex $2.0 B
Average of $400MM / Yr.



2015 – 2017*
Total Capex $1.2 B
Average of $393MM / Yr.



* Does not include forecasted capital expenditures for SourceGas or Peak View wind project

Capital Investment by Segment

PROFITABLE GROWTH

(in millions)	2011	2012	2013	2014	2015F	2016F	2017F
Generation	$85	$72	$130	$75	$62	$72	$32
Transmission	20	38	32	31	67	41	33
Distribution	44	44	48	87	49	60	44
Other	24	13	12	0	51	52	25
Subtotal Electric Utilities	173	167	222	193	230	225	135
Gas Utilities	44	46	63	71	69	60	72
Cost of Service Gas						50	100
Total Utilities	217	213	285	264	299	335	307
Power Generation	99	6	14	2	8	2	3
Coal	10	13	6	7	7	6	6
Oil and Gas	90	108	65	109	179	12	15
Total Non-Reg	199	127	84	118	194	20	24
Subtotal Utilities and Non Reg	416	340	369	382	493	355	331
Corporate	13	7	10	9	6	2	4
Total*	$429	$347	$379	$391	$499	$357	$335
Rider Eligible - Electric Utilities**					$81	$73	$30
Rider Eligible - Gas Utilities**					$13	$24	$32

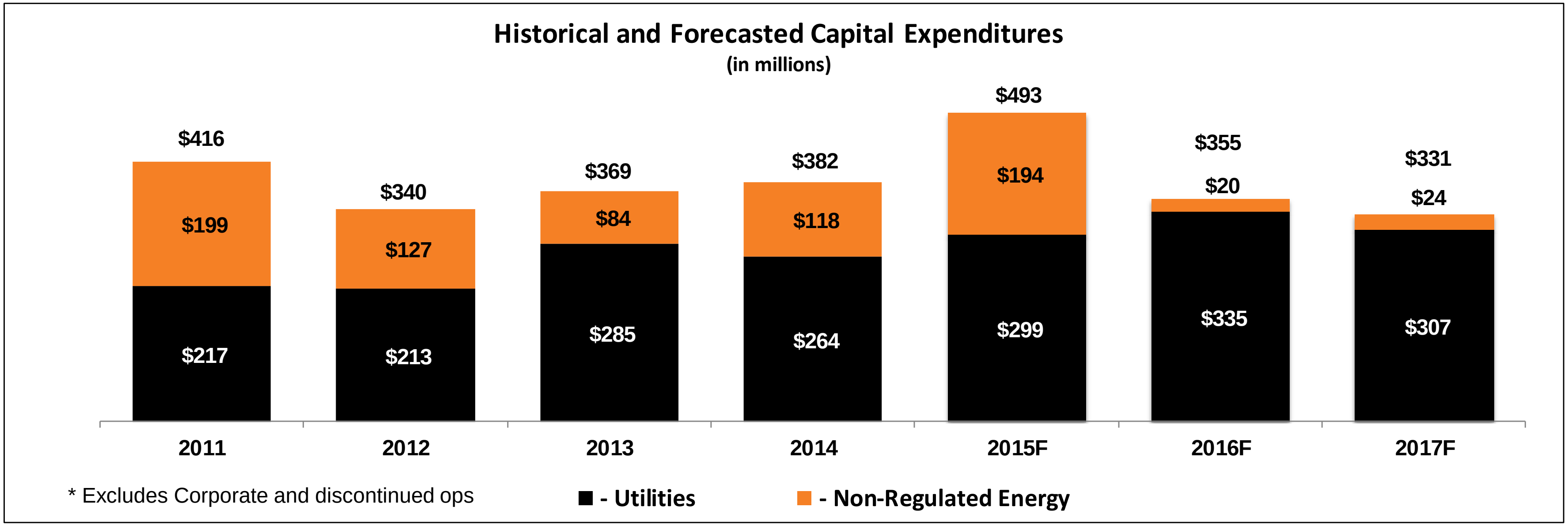
* Excludes SourceGas, Peak View wind project and discontinued operations

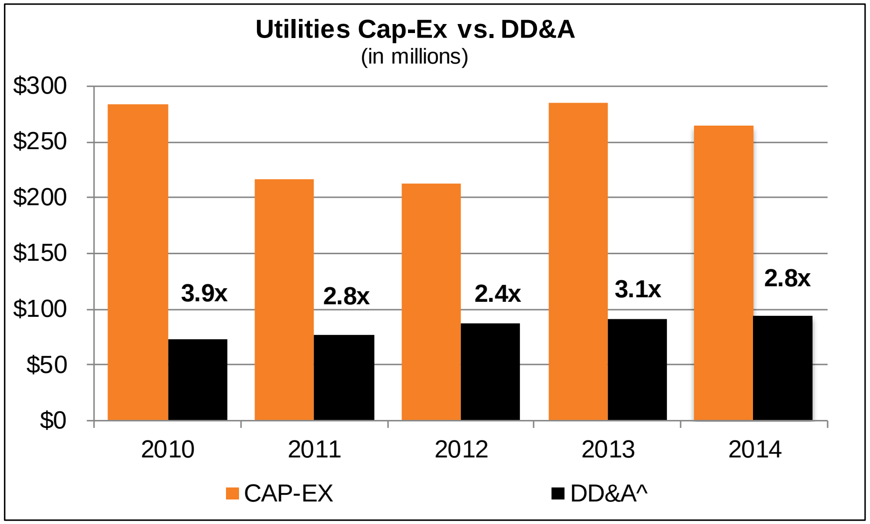
** Rider eligible capital expenditures included in the subtotals above for electric and gas utilities; excludes cost of service gas

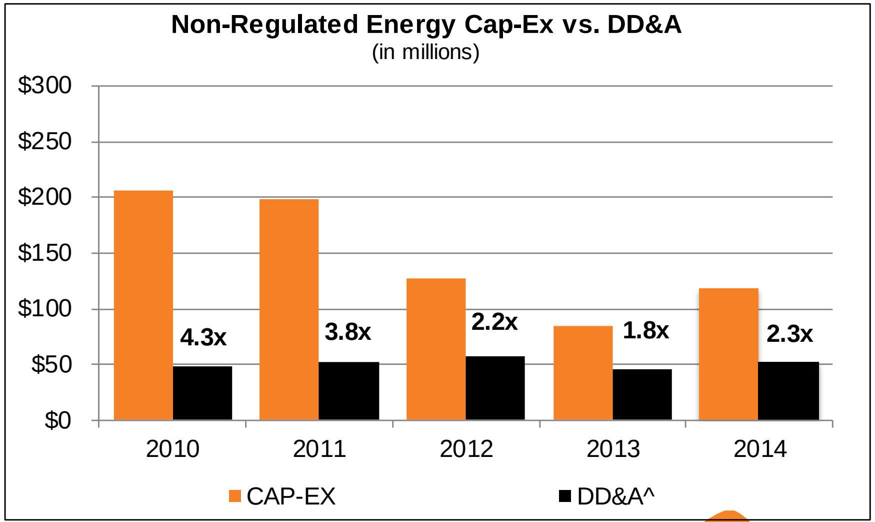
Note: differences due to rounding

PROFITABLE GROWTH

Capital Expenditures

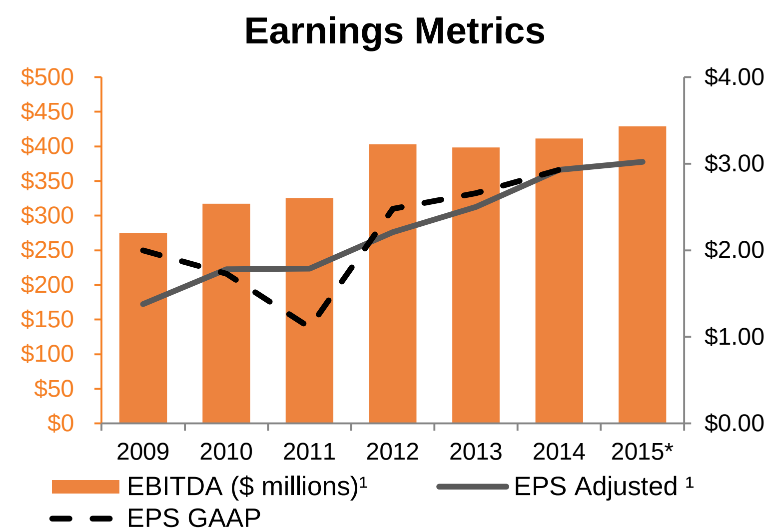


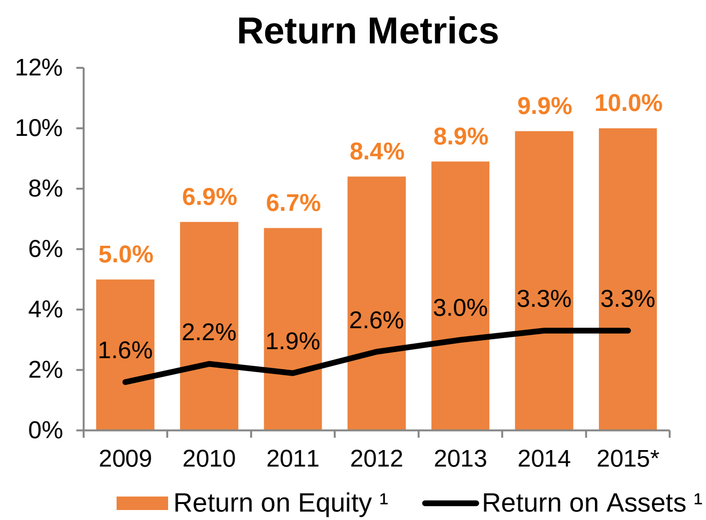


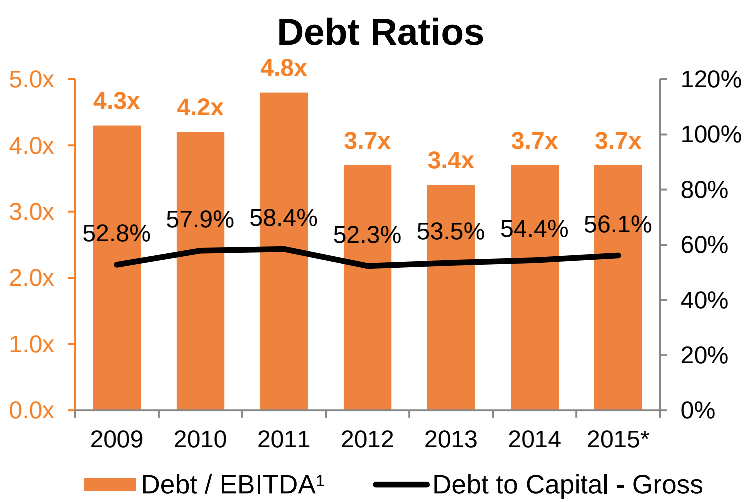


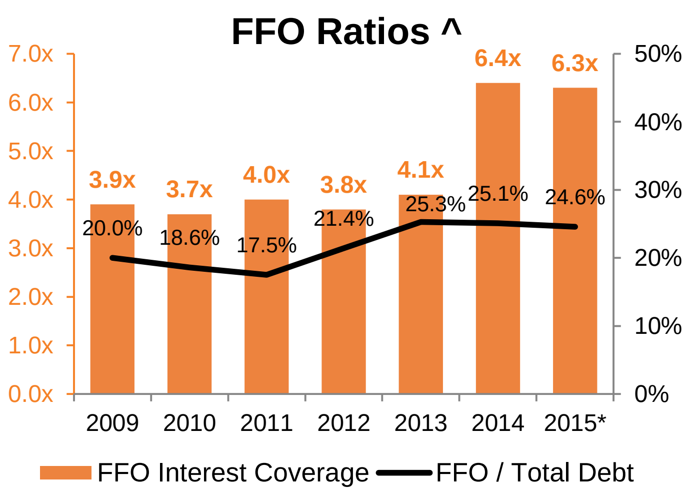
^ Non-GAAP measure, reconciled to GAAP in Appendix

Key Financial Metrics







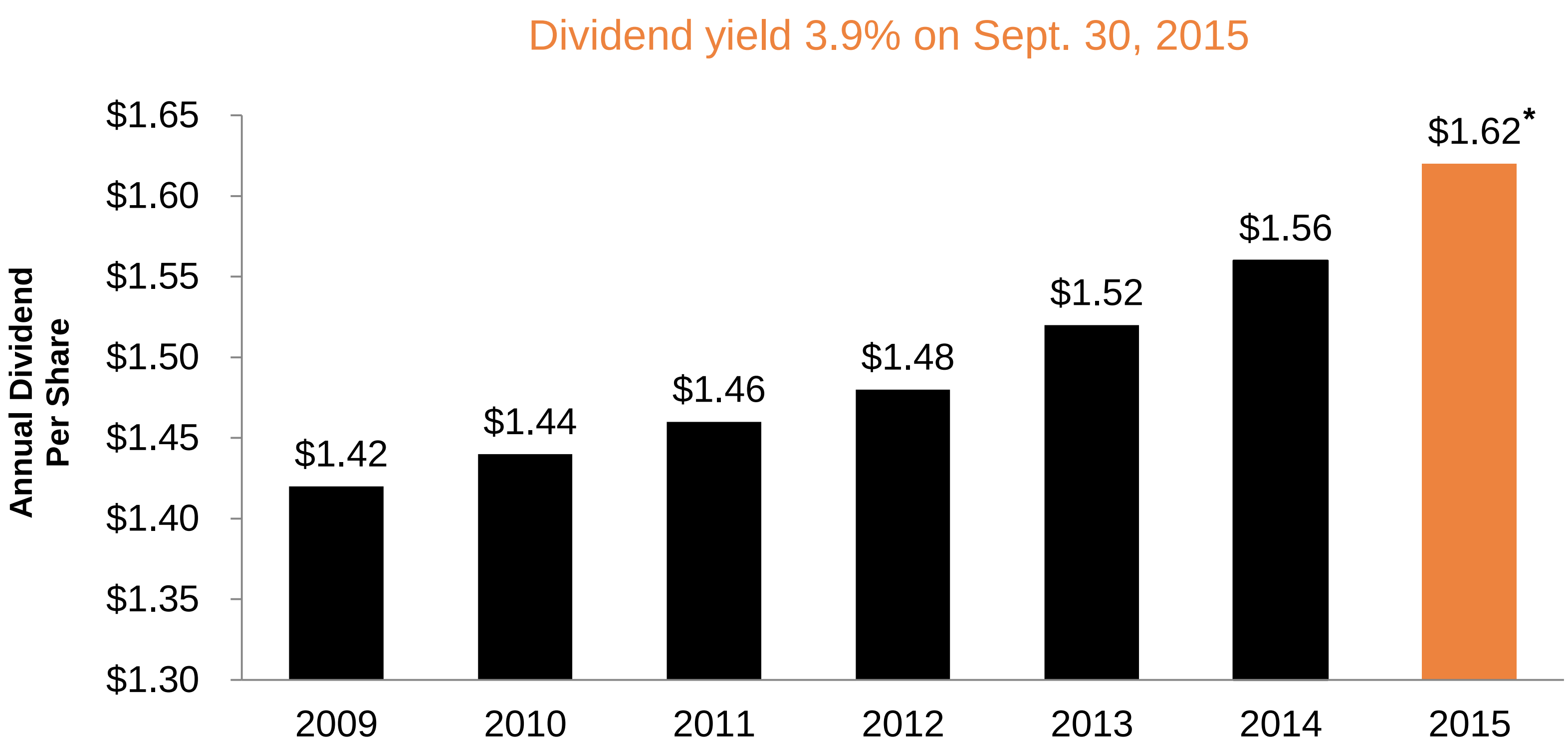


* Trailing four quarters as of June 2015
¹ Non–GAAP measure, reconciled to GAAP in Appendix
^ Calculated as cash earnings from Cash Flow Statements

PROFITABLE GROWTH

Dividend Growth

Dividend Increased for 45 Consecutive Years



* Board of Directors on July 28 declared quarterly dividend of $0.405 per share, equivalent to an annual rate of $1.62 per share

Capital Structure

(In millions, except for ratios)	June 30, 2015	Mar. 31, 2015	Dec. 31, 2014	Sept. 30, 2014	June 30, 2014
Capitalization					
Short-term Debt	$ 106	$ 103	$ 350	$ 459	$ 408
Long-term Debt	1,568	1,543	1,268	1,108	1,122
Total Debt	1,674	1,645	1,618	1,567	1,530
Equity*	1,311	1,372	1,354	1,335	1,318
Total Capitalization	$ 2,984	$ 3,017	$ 2,971	$ 2,901	$ 2,848
Net Debt to Net Capitalization					
Debt	$ 1,674	$ 1,645	$ 1,618	$ 1,567	$ 1,530
Cash and Cash Equivalents	(87)	(63)	(21)	(12)	(15)
Net Debt	1,586	1,583	1,596	1,555	1,515
Net Capitalization	$ 2,897	$ 2,953	$ 2,950	$ 2,889	$ 2,833
Debt to Capitalization*	56.1%	54.5%	54.4%	54.0%	53.7%
Net Debt to Capitalization (Net of Cash)*	54.8%	53.6%	54.1%	53.8%	53.5%
Long-term Debt to Total Debt	93.7%	93.8%	78.4%	70.7%	73.3%

* The after-tax, noncash impairments at Mar. 31 and June 30, 2015, reduced equity, which resulted in an increase in the company's debt to capitalization ratios at quarter-end

PROFITABLE GROWTH

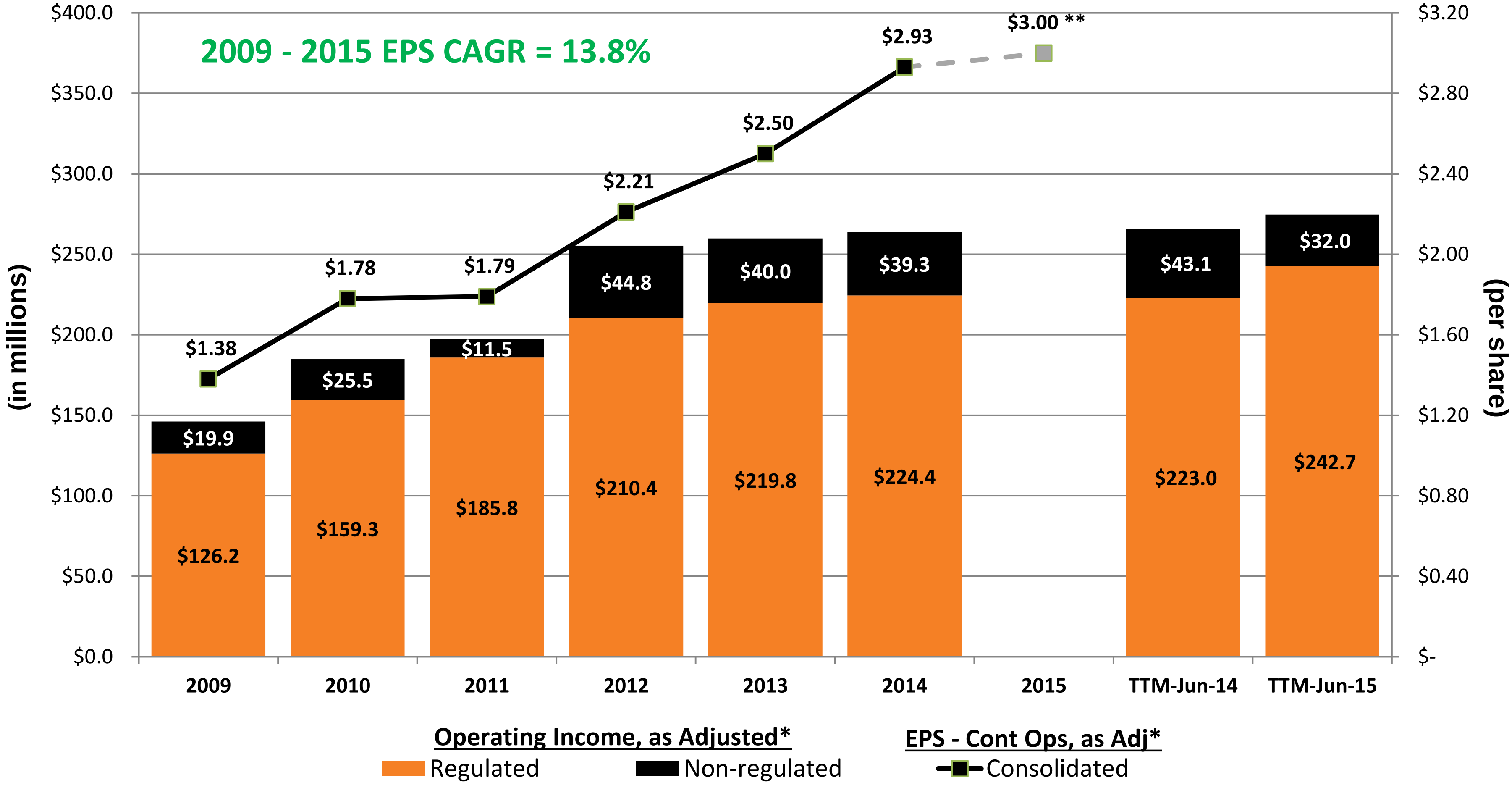
Credit Rating

- Following announcement of SourceGas acquisition, all three credit rating agencies reaffirmed their ratings; Moody's and Fitch adjusted outlook to negative
- Change to negative outlook reflects uncertainties around regulatory approvals, efficiencies and financing clarity for SourceGas acquisition

Black Hills Corporation	**S&P**	**Moody's**	**Fitch**
Corporate Credit Rating	BBB	Baa1	BBB+
Senior Unsecured	BBB	Baa1	BBB+
Outlook	*Stable*	*Negative Outlook*	*Negative Outlook*

Black Hills Power	**S&P**	**Moody's**	**Fitch**
Corporate Credit Rating	BBB	A3	BBB+
Senior Secured Debt	A-	A1	A

Operating Income and EPS, as Adjusted



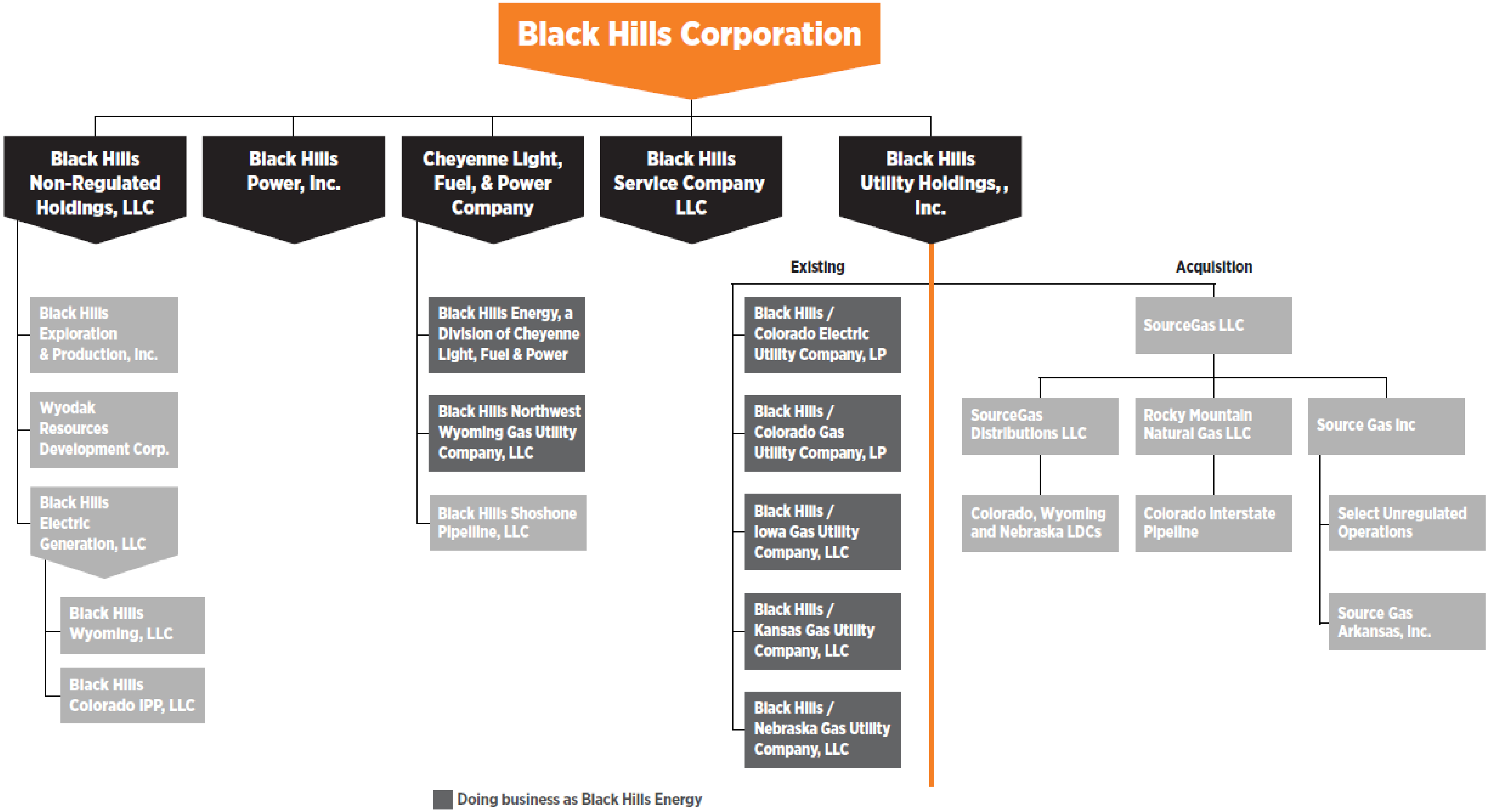
* Non-GAAP measures, reconciled to GAAP in Appendix (operating income, as adjusted graph does not include corporate activity)
** Midpoint of 2015 earnings guidance of $2.90 to $3.10 per share

Questions

Appendix

Wyodak Coal Mine, Gillette, Wyoming

Black Hills Organization Structure



Utility Regulatory Results

Jurisdiction	Electric Or Gas	Effective Date	Return on Equity	Capital Structure	Authorized Rate Base (in millions)
BHP-SD	Electric	10/01/2014	Global Settlement	Global Settlement	$543.9
BHP-WY	Electric	10/01/2014	9.90%	46.68% debt / 53.32% equity	$46.8
CLF&P	Electric	10/01/2014	9.90%	46% debt / 54% equity	$376.8
BHE-COE	Electric	1/1/2015	9.83%	50.2% debt / 49.8% equity	$448.3
CLF&P	Gas	10/01/2014	9.90%	46% debt / 54% equity	$59.6
BHE-CO Gas	Gas	12/10/2012	9.6%	50% debt / 50% equity	$57.5
BHE-IA Gas	Gas	2/10/2011	Global Settlement	Global Settlement	$109.2
BHE-KS Gas	Gas	1/1/2015	Global Settlement	Global Settlement	Global Settlement
BHE-NE Gas	Gas	9/1/2010	10.1%	48% debt / 52% equity	$161.0
Total					$1,803.1

Note: Information from last approved rate case in each jurisdiction

Estimated Utility Rate Base

Estimated Rate Base* by Utility Segment (in millions)	2010	2011	2012	2013	2014
Electric Utilities	$901	$1,007	$1,272	$1,248	$1,487
Gas Utilities	$425	$443	$450	$454	$489
Total	$1,326	$1,450	$1,722	$1,702	$1,976

* Estimated rate base determined at year-end and calculated using state specific requirements; includes capital expenditures through trackers but excludes construction work in-progress

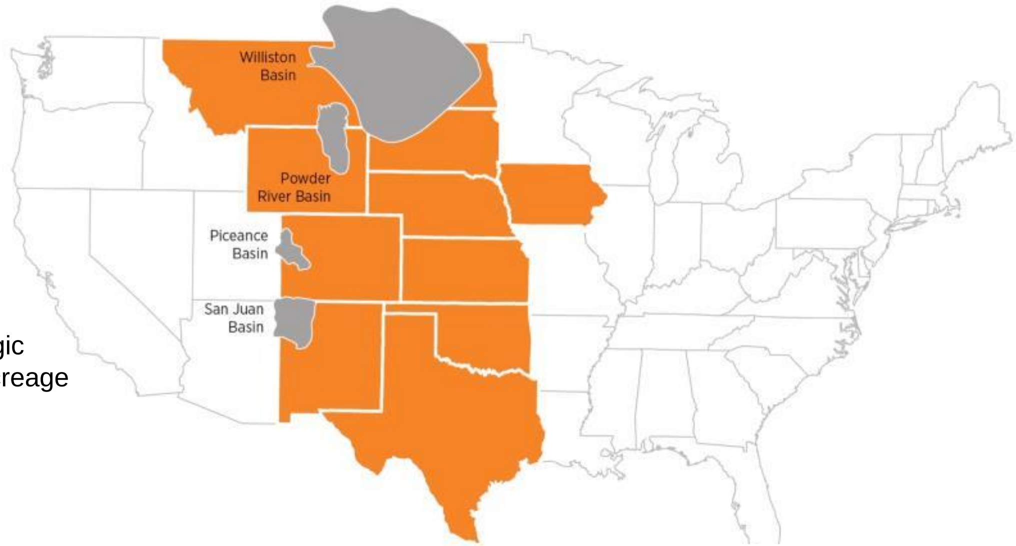
VALUED SERVICE

Regulatory Update

Utility & Filing	Description*	Filing Date	2013	2014	2015	Status
BHP Rate case SD	CPGS - $14.6MM request, 53%/47%, 10.25% ROE	Q1 2014				Approved 3-2-15; $6.9MM, Effective 10-1-14; Appeal pending in circuit court. Global Settlement
COE CPCN	New 60 MW wind farm	Q2 2015				Settlement agreement reached; Oct. deliberations by CO PUC with expected approval in Nov.
COE Rate case	$7.2MM revised request, 50.54%/49.46%,10.3% ROE; includes Busch Ranch Wind Farm; requests CACJA rider	Q2 2014				Approved 12-22-14; $3.1MM, 49.8%/50.2%, ROE 9.83%, Effective 1-1-15
KS Gas Rate case	$7.3MM request, 50.3%/49.7%, 10.6% ROE	Q2 2014				Approved 12-16-14; $5.2MM,Effective 1-1-15. Global Settlement

* Equity / debt ratio

Oil and Gas Properties



Note: approximate areas of geologic basins – does not reflect BHEP acreage

June 2014 Average Production

Basin	Daily Net Gas (MCFD)	Daily Net NGL (GPD)	Daily Net Oil (BPD)
Williston	405	3,723	287
Powder River	759	8,378	683
Piceance	5,843	6,610	17
San Juan	10,110	0	8
Other	2,954	0	25
Total	20,071	18,711	1,020

June 2015 Average Production

Basin	Daily Net Gas (MCFD)	Daily Net NGL (GPD)	Daily Net Oil (BPD)
Williston	559	203	450
Powder River	809	7,438	716
Piceance	17,407	9,835	79
San Juan	9,784	0	10
Other	3,180	49	22
Total	31,739	17,526	1,276

Reserve Data and Net Present Value

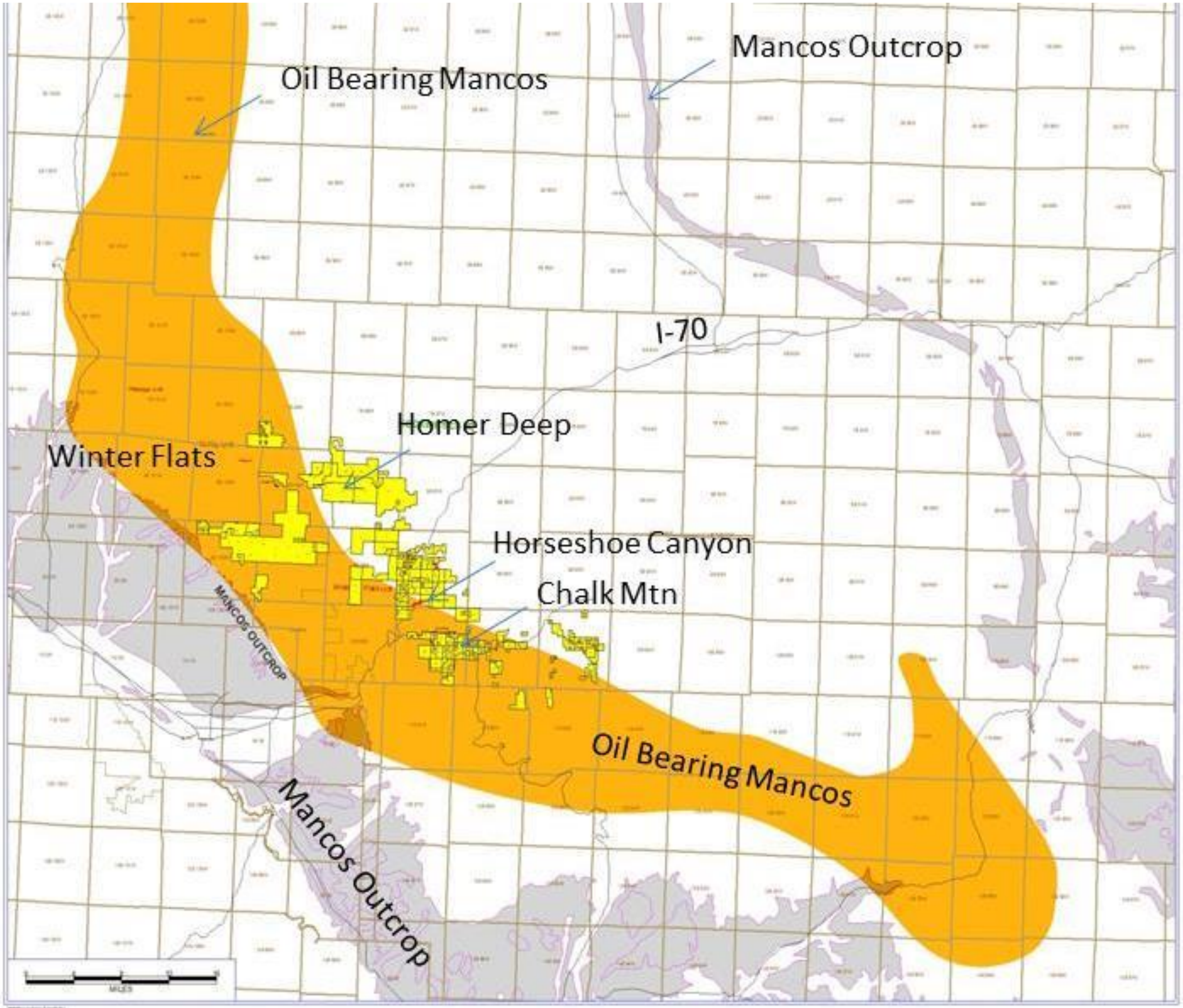
Reserve calculation at Dec. 31, 2014

	Net Oil (MMBO) **	Net Gas (BCF)**	Net NGL (MMB)	Net Equiv (BCFE)* *	PV10 (MM)	Average Price Oil Per BBL ^	Average Price Nat Gas per MCF ^	Average Price NGL Per BBL
PDP*	3.8	51.7	1.5	83.2	$176.4	$85.70	$3.36	$33.54
PNP*	-	4.9	0.06	5.3	$6.2	-	$3.02	$41.07
PBP*	-	0.8	-	0.8	$0.6	-	$3.96	-
PUD*	0.5	8.0	0.2	12.1	($3.1)	$86.59	$3.26	$42.71
Other	-	-	-	-	$8.7	-	-	-
Total**	4.3	65.4	1.7	101.4	$188.7	$85.80	$3.33	$34.81

^ Average wellhead pricing used in determination of PV10 calculation (held constant for life of production)
* PDP – proved developed producing, PNP – proved not producing, PBP – proven behind pipe, PUD – proved undeveloped
** Information from 2014 Year-End Reserves Study

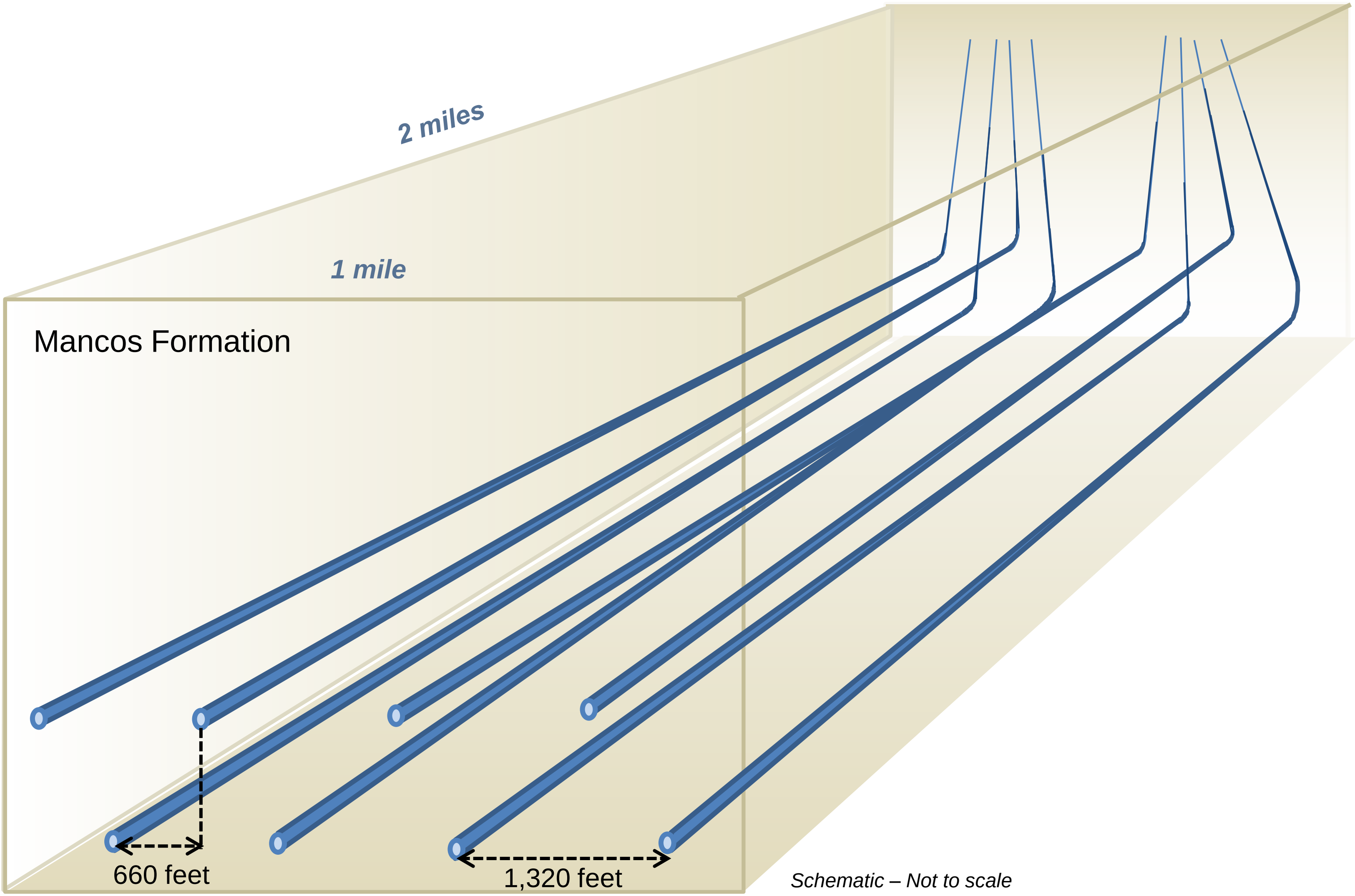
PROFITABLE GROWTH

Southern Piceance Basin – Liquids Potential



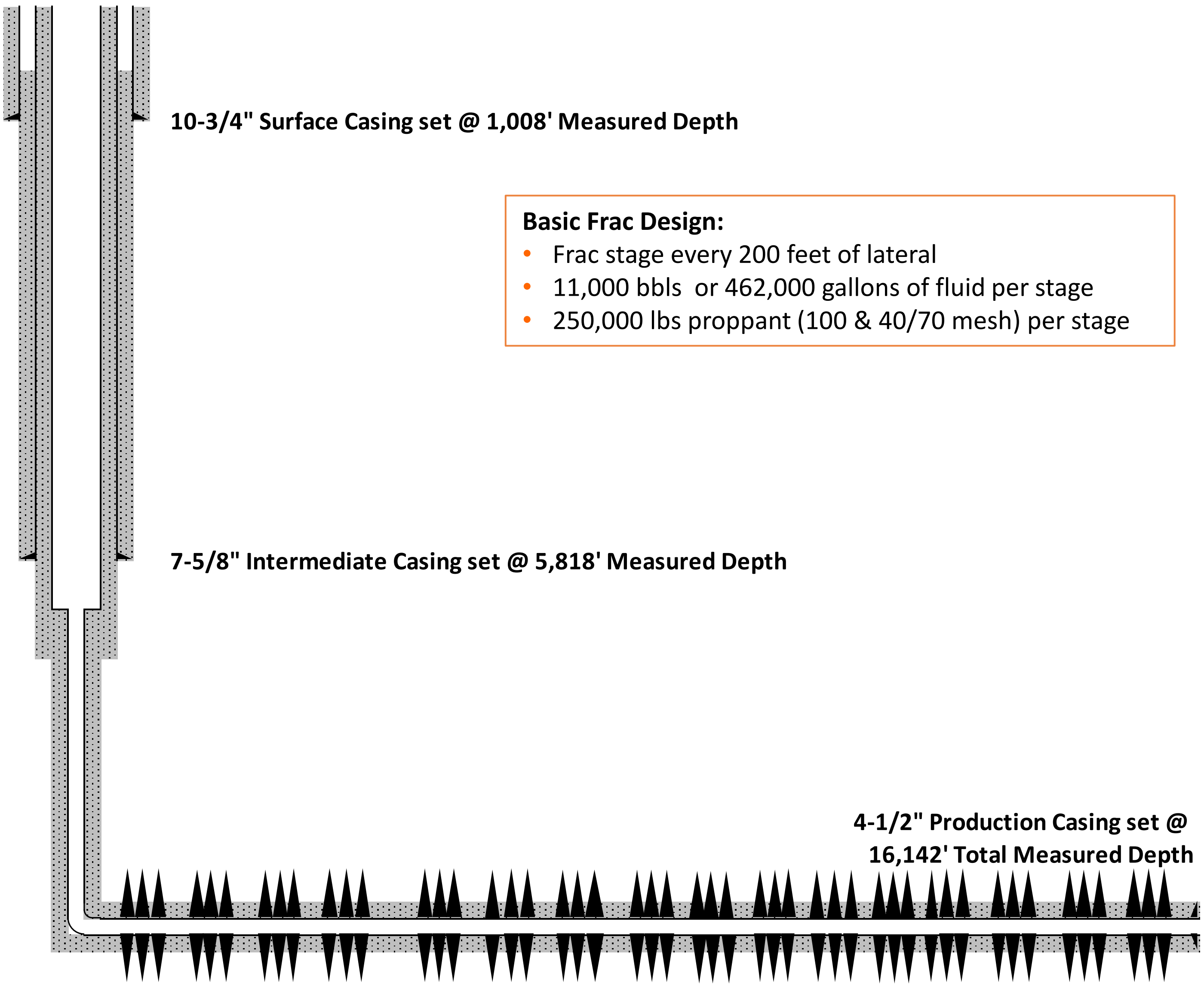
Southern Piceance - Mancos Shale

Horizontal Well – Pad Spacing



Schematic – Not to scale

Current Mancos Well Plan



Basic Frac Design:
- Frac stage every 200 feet of lateral
- 11,000 bbls or 462,000 gallons of fluid per stage
- 250,000 lbs proppant (100 & 40/70 mesh) per stage

Income Statement

June 30, 2015 and 2014

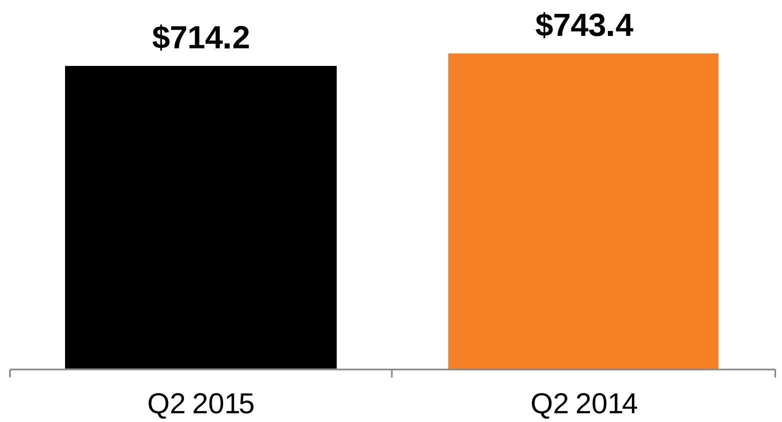
(In millions, except per share amounts)

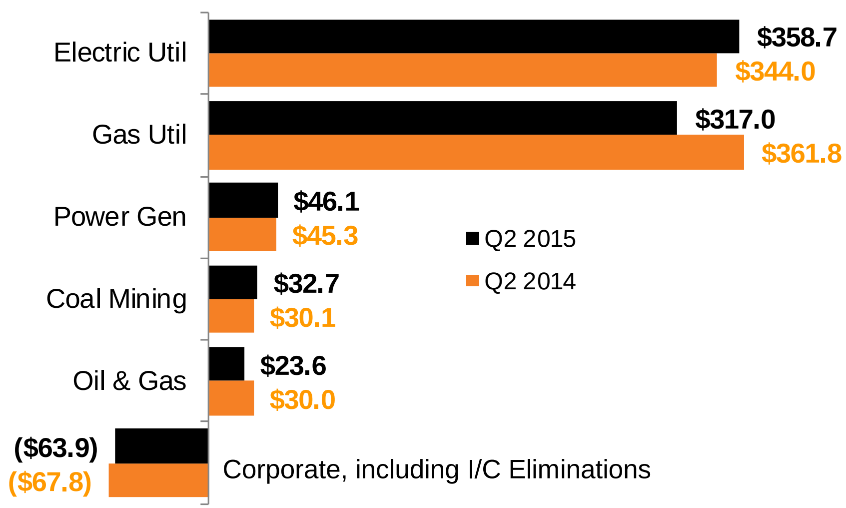
	Year to Date 2015 Actual		Year to Date 2014 Actual	
Revenue	$	714.2	$	743.4
Fuel cost		(279.1)		(331.8)
Gross margin		435.1		411.6
Operating expense		(207.4)		(202.6)
DD&A		(79.1)		(71.1)
Subtotal		**148.6**		**137.9**
Impairment of Oil and Gas assets		(116.5)		-
Acquisition costs		(0.5)		-
Operating income		**31.6**		**137.9**
Interest expense, net		(37.6)		(33.8)
Other income		0.6		1.5
Impairment of equity investment (BHEP)		(5.2)		-
Income before income tax		(10.6)		105.6
Income tax		2.6		(36.6)
Net income	**$**	**(8.0)**	**$**	**69.0**
Non-GAAP adjustments		81.0		-
Net income, as adjusted *	**$**	**73.0**	**$**	**69.0**
EPS	$	(0.18)	$	1.55
EPS, as adjusted *	**$**	**1.64**	**$**	**1.55**
Diluted Shares Outstanding		44.6		44.6
EBITDA, as adjusted *	**$**	**228.2**	**$**	**210.5**

* Non-GAAP measures, defined and/or reconciled to GAAP in the Appendix

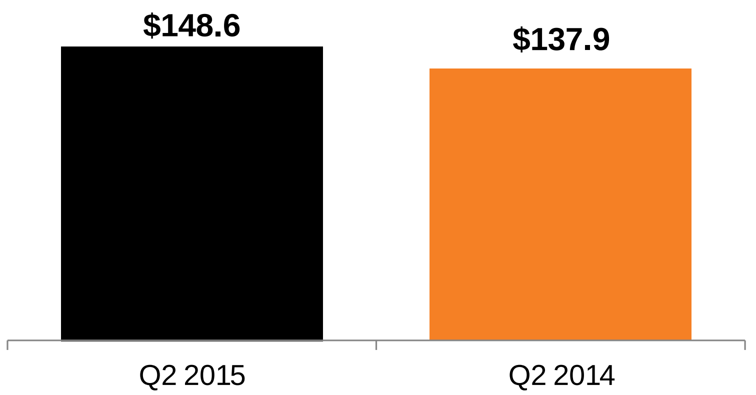
YTD June Revenue/Op Income

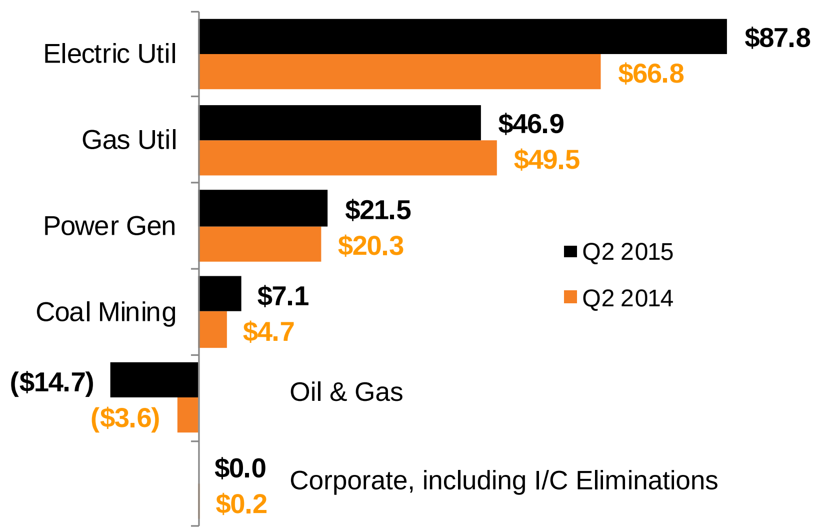
Total Revenue, as adjusted* (in millions)





Total Operating Income, as adjusted* (in millions)





* Non-GAAP measures, reconciled to GAAP in Appendix

Use of Non-GAAP Financial Measures

Gross Margin
Our financial information includes the financial measure Gross Margin, which is considered a "non-GAAP financial measure." Generally, a non-GAAP financial measure is a numerical measure of a company's financial performance, financial position or cash flows that excludes (or includes) amounts that are included in (or excluded from) the most directly comparable measure calculated and presented in accordance with GAAP. Gross Margin (Revenues less Cost of Sales) is a non-GAAP financial measure due to the exclusion of depreciation from the measure. The presentation of Gross Margin is intended to supplement investors' understanding of our operating performance.

Gross Margin is calculated as operating revenue less cost of fuel, purchased power and cost of gas sold. Our Gross Margin is impacted by the fluctuations in power purchases and natural gas and other fuel supply costs. However, while these fluctuating costs impact Gross Margin as a percentage of revenue, they only impact total Gross Margin if the costs cannot be passed through to our customers.

Our Gross Margin measure may not be comparable to other companies' Gross Margin measure. Furthermore, this measure is not intended to replace operating income as determined in accordance with GAAP as an indicator of operating performance.

EBITDA and EBITDA, as adjusted
We believe that our presentation of earnings before interest, income taxes, depreciation and amortization (EBITDA) and EBITDA, as adjusted (EBITDA) adjusted for special items as defined by management), both non-GAAP measures, are important supplemental measures of operating performance. We believe EBITDA and EBITDA, as adjusted, when considered with measures calculated in accordance with GAAP, give investors a more complete understanding of operating results before the impact of investing and financing transactions and income taxes. We have chosen to provide this information to investors to enable them to perform more meaningful comparisons of past and present operating results and as a means to evaluate the results of core on-going operations.

Our presentation of EBITDA may be different from the presentation used by other companies and, therefore, comparability may be limited. Depreciation and amortization expense, interest expense, income taxes and other items have been and will be incurred and are not reflected in the presentation of EBITDA. Each of these items should also be considered in the overall evaluation of our results. Additionally, EBITDA does not consider capital expenditures and other investing activities and should not be considered a measure of our liquidity. We compensate for these limitations by providing relevant disclosure of our depreciation and amortization, interest and income taxes, capital expenditures and other items both in our reconciliation to the GAAP financial measures and in our consolidated financial statements, all of which should be considered when evaluating our performance.

Note: continued on next page

Use of Non-GAAP Financial Measures

Segment Revenue, Operating Income, Income from Continuing Operations and EPS, as adjusted
We have provided non-GAAP earnings data reflecting adjustments for special items as specified in the GAAP to non-GAAP adjustment reconciliation table in this presentation. Segment Revenue, as adjusted, Operating Income (loss), as adjusted, Income (loss) from continuing operations, as adjusted, and Net income (loss), as adjusted, are defined as Segment Revenue, Operating Income (loss), Income (loss) from continuing operations and Net income (loss), adjusted for expenses, gains and losses that the company believes do not reflect the company's core operating performance. The company believes that non-GAAP financial measures are useful to investors because the items excluded are not indicative of the company's continuing operating results. The company's management uses these non-GAAP financial measures as an indicator for planning and forecasting future periods.

Earnings per share, as adjusted
Earnings per share, as adjusted, is a Non-GAAP financial measure. Earnings per share, as adjusted, is defined as GAAP Earnings per share, adjusted for expenses and gains that the Company believes do not reflect the Company's core operating performance. Examples of these types of adjustments may include unique one-time non-budgeted events, impairment of assets, acquisition and disposition costs, and other adjustments noted in the earnings reconciliation tables in this presentation. The Company is not able to provide a forward-looking quantitative GAAP to Non-GAAP reconciliation for this financial measure because we do not know the unplanned or unique events that may occur later during the year.

Depreciation, Depletion and Amortization, as adjusted
Depreciation, Depletion and Amortization (DD&A), as adjusted are defined as DD&A by segment adjusted for additional depreciation expense at our Utilities Group and reduced depreciation at our Non-regulated Group. We have provided this non-GAAP measure to reflect adjustments by Business Group for the requirement under GAAP that the power purchase agreement between Colorado Electric and Colorado IPP be accounted for as a capital lease. The company believes that non-GAAP measures are useful to investors because the lease accounting is not indicative of our rate recovery accounting. The company's management uses these non-GAAP financial measures as an indicator for evaluating current periods and planning and forecasting future periods.

Limitations on the Use of Non-GAAP Measures
Non-GAAP measures have limitations as analytical tools and should not be considered in isolation or as a substitute for analysis of our results as reported under GAAP. Our presentation of these non-GAAP financial measures should not be construed as an inference that our future results will not be affected by unusual, non-routine, or non-recurring items.

Non-GAAP measures should be used in addition to and in conjunction with results presented in accordance with GAAP. Non-GAAP measures should not be considered as an alternative to net income, operating income or any other operating performance measure prescribed by GAAP, nor should these measures be relied upon to the exclusion of GAAP financial measures. Our non-GAAP measures reflect an additional way of viewing our operations that we believe, when viewed with our GAAP results and the reconciliation to the corresponding GAAP financial measures, provide a more complete understanding of factors and trends affecting our business than could be obtained absent this disclosure. Management strongly encourages investors to review our financial information in its entirety and not rely on a single financial measure.

Use of Non-GAAP Financial Measures

2015 Guidance

	Low	High
Earnings Per Share (GAAP)	$ 1.08	$ 1.28
Adjustments, after tax:*		
Asset impairment - Oil and Gas	1.73	1.73
Impairment of equity investments - Oil and Gas	0.08	0.08
Acquisition / integration expenses	0.01	0.01
Total Adjustments	1.82	1.82
Earnings per share, as adjusted (Non-GAAP)	**$ 2.90**	**$ 3.10**

* Adjustments, after tax are actuals through June 30, 2015. The Company is not able to provide forward-looking quantitative financial measures because we do not know the unplanned or unique events that may occur later during the year

Use of Non-GAAP Financial Measures

Revenue, as adjusted

(in thousands) **YTD June 30, 2015**	Utilities		Non-Regulated Energy				
	Electric Utilities	**Gas Utilities**	**Power Generation**	**Coal Mining**	**Oil & Gas**	**Corporate**	**Total**
Revenue	$ 352,725	$ 317,077	$ 3,659	$ 17,194	$ 23,586	$ -	$ 714,241
Inter-company revenue	5,933	—	41,324	15,465	—	(62,722)	—
Total revenue (GAAP)	358,658	317,077	44,983	32,659	23,586	(62,722)	714,241
Less: - Inter-company capital lease	—	—	1,154	—	—	(1,154)	—
Revenue, as adjusted - (Non-GAAP)	**$ 358,658**	**$ 317,077**	**$ 46,137**	**$ 32,659**	**$ 23,586**	**$ (63,876)**	**$ 714,241**

YTD June 30, 2014	Utilities		Non-Regulated Energy				
	Electric Utilities	**Gas Utilities**	**Power Generation**	**Coal Mining**	**Oil & Gas**	**Corporate**	**Total**
Revenue	$ 336,835	$ 361,836	$ 2,536	$ 12,201	$ 29,998	$ -	$ 743,406
Inter-company revenue	7,151	—	41,792	17,948	—	(66,891)	—
Total revenue (GAAP)	343,986	361,836	44,328	30,149	29,998	(66,891)	743,406
Less: - Inter-company capital lease	—	—	1,016	—	—	(1,016)	—
Revenue, as adjusted - (Non-GAAP)	**$ 343,986**	**$ 361,836**	**$ 45,344**	**$ 30,149**	**$ 29,998**	**$ (67,907)**	**$ 743,406**

Use of Non-GAAP Financial Measures

Operating Income, as adjusted

(in thousands, pre-tax)

YTD June 30, 2015

	Utilities		Non-Regulated Energy				
	Electric Utilities	Gas Utilities	Power Generation	Coal Mining	Oil & Gas	Corporate	Total
Operating income (loss) (GAAP)	$ 83,523	$ 46,868	$ 26,422	$ 7,130	$ (131,140)	$ (1,161)	$ 31,642
Capital lease adjustment	4,268	—	(4,936)	—	—	668	—
Operating income without capital lease (Non-GAAP)	87,791	46,868	21,486	7,130	(131,140)	(493)	31,642
Significant Unique Items:							
Impairment of Long Lived Assets - BHEP	—	—	—	—	116,520	—	116,520
Acquisition Costs Combined (SourceGas, NW & NE Wyo)	—	—	—	—	—	475	475
Total Adjustments	—	—	—	—	116,520	475	116,995
Operating income (loss), as adjusted (Non-GAAP)	**$ 87,791**	**$ 46,868**	**$ 21,486**	**$ 7,130**	**$ (14,620)**	**$ (18)**	**$ 148,637**

YTD June 30, 2014

	Utilities		Non-Regulated Energy				
	Electric Utilities	Gas Utilities	Power Generation	Coal Mining	Oil & Gas	Corporate	Total
Operating income (loss) (GAAP)	$ 62,286	$ 49,508	$ 25,555	$ 4,735	$ (3,634)	$ (606)	$ 137,844
Capital lease adjustment	4,529	—	(5,349)	—	—	820	—
Operating income without capital lease (Non-GAAP)	66,815	49,508	20,206	4,735	(3,634)	214	137,844
Significant Unique Items:							
Total Adjustments	—	—	—	—	—	—	—
Operating income (loss), as adjusted (Non-GAAP)	**$ 66,815**	**$ 49,508**	**$ 20,206**	**$ 4,735**	**$ (3,634)**	**$ 214**	**$ 137,844**

Use of Non-GAAP Financial Measures

Operating Income, as adjusted

(in thousands, pre-tax)

Trailing Twelve Months, June 30, 2015	Utilities		Non-Regulated Energy				
	Electric Utilities	Gas Utilities	Power Generation	Coal Mining	Oil & Gas	Corporate	Total
Operating income (loss) (GAAP)	$ 158,910	$ 75,142	$ 50,759	$ 14,305	$ (139,297)	$ (2,153)	$ 157,666
Capital lease adjustment	8,671	-	(10,320)	-	-	1,649	—
Operating income without capital lease (Non-GAAP)	167,581	75,142	40,439	14,305	(139,297)	(504)	157,666
Significant unique items:							
Impairment of Long Lived Assets	—	—	—	—	116,520	—	116,520
Acquisition Costs Combined (SourceGas, NW & NE Wyo)	—	—	—	—	—	475	475
Total adjustments	—	—	—	—	116,520	475	116,995
Operating income (loss), as adjusted (Non-GAAP)	**$ 167,581**	**$ 75,142**	**$ 40,439**	**$ 14,305**	**$ (22,777)**	**$ (29)**	**$ 274,661**

Trailing Twelve Months, June 30, 2014	Utilities		Non-Regulated Energy				
	Electric Utilities	Gas Utilities	Power Generation	Coal Mining	Oil & Gas	Corporate	Total
Operating income (loss) (GAAP)	$ 134,255	$ 79,553	$ 51,321	$ 7,651	$ (5,265)	$ (1,055)	$ 266,460
Capital lease adjustment	9,176	-	(10,611)	-	-	1,435	—
Operating income without capital lease (Non-GAAP)	143,431	79,553	40,710	7,651	(5,265)	380	266,460
Significant unique items:							
Total adjustments	—	—	—	—	—	—	—
Operating income (loss), as adjusted (Non-GAAP)	**$ 143,431**	**$ 79,553**	**$ 40,710**	**$ 7,651**	**$ (5,265)**	**$ 380**	**$ 266,460**

Use of Non-GAAP Financial Measures

Operating Income, as adjusted

YTD Dec. 31, 2014	Utilities		Non-Regulated Energy				
	Electric Utilities	Gas Utilities	Power Generation	Coal Mining	Oil and Gas	Corporate	Total
Operating income (loss) (GAAP)	$ 137,673	$ 77,782	$ 49,892	$ 11,910	$ (11,791)	$ (1,598)	$ 263,868
Capital lease adjustment	8,931	—	(10,733)	—	—	1,802	—
Operating income without capital lease (Non-GAAP)	146,604	77,782	39,159	11,910	(11,791)	204	263,868
Total adjustments	—	—	—	—	—	—	—
Operating income (loss), as adjusted (Non-GAAP)	**$ 146,604**	**$ 77,782**	**$ 39,159**	**$ 11,910**	**$ (11,791)**	**$ 204**	**$ 263,868**

YTD Dec. 31, 2013	Utilities		Non-Regulated Energy				
	Electric Utilities	Gas Utilities	Power Generation	Coal Mining	Oil and Gas	Corporate	Total
Operating income (loss) (GAAP)	$ 133,595	$ 76,772	$ 47,760	$ 5,586	$ (3,357)	$ (910)	$ 259,446
Capital lease adjustment	9,413	—	(10,003)	—	—	590	—
Operating income without capital lease (Non-GAAP)	143,008	76,772	37,757	5,586	(3,357)	(320)	259,446
Total adjustments	—	—	—	—	—	—	—
Operating income (loss), as adjusted (Non-GAAP)	**$ 143,008**	**$ 76,772**	**$ 37,757**	**$ 5,586**	**$ (3,357)**	**$ (320)**	**$ 259,446**

YTD Dec. 31, 2012	Utilities		Non-Regulated Energy				
	Electric Utilities	Gas Utilities	Power Generation	Coal Mining	Oil and Gas	Corporate	Total
Operating income (loss) (GAAP)	$ 131,721	$ 66,179	$ 44,799	$ 2,165	$ 32,302	$ (725)	$ 276,441
Capital lease adjustment	9,820	—	(9,445)	—	—	(375)	—
Operating income without capital lease (Non-GAAP)	141,541	66,179	35,354	2,165	32,302	(1,100)	276,441
Significant unique items:							
Gain on sale of Williston Basin assets	—	—	—	—	(75,853)	—	(75,853)
Incentive compensation - Williston Basin asset sale	1,595	1,104	105	237	967	—	4,008
Impairment of Oil and Gas assets	—	—	—	—	49,571	—	49,571
Total adjustments	1,595	1,104	105	237	(25,315)	—	(22,274)
Operating income (loss), as adjusted (Non-GAAP)	**$ 143,136**	**$ 67,283**	**$ 35,459**	**$ 2,402**	**$ 6,987**	**$ (1,100)**	**$ 254,167**

Use of Non-GAAP Financial Measures

Operating Income, as adjusted

(in thousands, pre-tax)

YTD Dec. 31, 2011	Utilities: Electric Utilities	Utilities: Gas Utilities	Non-Regulated Energy: Power Generation	Non-Regulated Energy: Coal Mining	Non-Regulated Energy: Oil and Gas	Corporate	Total
Operating income (loss) (GAAP)	$ 109,457	$ 76,336	$ 10,935	$ (8,395)	$ 8,967	$ (4,832)	$ 192,468
Total adjustments	—	—	—	—	—	—	—
Operating income (loss), as adjusted (Non-GAAP)	**$ 109,457**	**$ 76,336**	**$ 10,935**	**$ (8,395)**	**$ 8,967**	**$ (4,832)**	**$ 192,468**

YTD Dec. 31, 2010	Utilities: Electric Utilities	Utilities: Gas Utilities	Non-Regulated Energy: Power Generation	Non-Regulated Energy: Coal Mining	Non-Regulated Energy: Oil and Gas	Corporate	Total
Operating income (loss) (GAAP)	$ 99,292	$ 68,968	$ 9,673	$ 4,731	$ 11,143	$ (3,826)	$ 189,981
Significant unique items:							
Sale of Elkhorn	—	(2,683)	—	—	—	—	(2,683)
Sale of Wygen III to City of Gillette	(6,238)	—	—	—	—	—	(6,238)
Total adjustments	(6,238)	(2,683)	—	—	—	—	(8,921)
Operating income (loss), as adjusted (Non-GAAP)	**$ 93,054**	**$ 66,285**	**$ 9,673**	**$ 4,731**	**$ 11,143**	**$ (3,826)**	**$ 181,060**

YTD Dec. 31, 2009	Utilities: Electric Utilities	Utilities: Gas Utilities	Non-Regulated Energy: Power Generation	Non-Regulated Energy: Coal Mining	Non-Regulated Energy: Oil and Gas	Corporate	Total
Operating income (loss) (GAAP)	$ 70,968	$ 55,210	$ 40,055	$ 5,055	$ (42,521)	$ (4,612)	$ 124,155
Capital lease adjustment	—	—	—	—	—	—	—
Operating income without capital lease (Non-GAAP)	70,968	55,210	40,055	5,055	(42,521)	(4,612)	124,155
Significant unique items:							
Asset impairment	—	—	—	—	43,301	—	43,301
23.5% of Wygen I to MEAN	—	—	(25,971)	—	—	—	(25,971)
Integration expense (Aquila Transaction)	—	—	—	—	—	5,291	5,291
Total adjustments	—	—	(25,971)	—	43,301	5,291	22,621
Operating income (loss), as adjusted (Non-GAAP)	**$ 70,968**	**$ 55,210**	**$ 14,084**	**$ 5,055**	**$ 780**	**$ 679**	**$ 146,776**

Use of Non-GAAP Financial Measures

EBITDA, as adjusted

EBITDA, as adjusted	YTD	YTD	YTD	YTD	YTD	YTD	6 mths					2015
(in thousands)	2009	2010	2011	2012	2013	2014	June 2014	Q3 2014	Q4 2014	Q1 2015	Q2 2015	Trailing Qtr's
Income from continuing operations (GAAP)	$ 77,269	$ 67,361	$ 44,374	$ 109,416	$ 118,308	$ 130,889	$ 68,992	$ 27,363	$ 34,534	$ 33,850	$ (41,841)	$ 53,906
Depreciation, depletion and amortization	120,938	120,046	129,361	145,923	137,323	144,744	71,126	36,629	36,990	39,002	40,051	152,672
Impairment of Oil and Gas Assets	43,301	-	-	49,571	-	-	-	-	-	22,036	94,484	116,520
Interest expense, net	82,330	90,064	89,367	111,652	110,065	69,036	33,751	16,795	18,489	19,028	18,556	72,868
Unrealized (gain) loss on interest rate swaps, net	(55,653)	15,193	42,010	(1,882)	(30,169)	-	-	-	-	-	-	-
Income tax benefit (expense)	32,851	24,508	20,445	60,219	63,041	66,625	36,632	11,639	18,353	17,712	(20,317)	27,387
Rounding	-	(1)	(1)	1	(1)	-	-	(1)	1	-	(1)	(1)
EBITDA	**301,036**	**317,171**	**325,556**	**474,900**	**398,567**	**411,294**	**210,501**	**92,425**	**108,367**	**131,628**	**90,932**	**423,353**
Less adjustments:												
Gain on sale of operating assets -												
- Williston Basin assets	-	-	-	(75,854)	-	-	-	-	-	-	-	-
- Sale of Elkhorn, NE service area	-	(2,683)	-	-	-	-	-	-	-	-	-	-
- Partial sale of Wygen III to City of Gillette	-	(6,238)	-	-	-	-	-	-	-	-	-	-
- Partial sale of Wygen I to MEAN	(25,971)	-	-	-	-	-	-	-	-	-	-	-
Incentive compensation - Williston Basin assets	-	-	-	4,008	-	-	-	-	-	-	-	-
Acquisition/Integration expenses	5,291	-	-	-	-	-	-	-	-	(292)	768	476
Impairment of equity investments - Oil and Gas	-	-	-	-	-	-	-	-	-	-	5,170	5,170
EBITDA, as adjusted	**$ 280,356**	**$ 308,250**	**$ 325,556**	**$ 403,054**	**$ 398,567**	**$ 411,294**	**$ 210,501**	**$ 92,425**	**$ 108,367**	**$ 131,336**	**$ 96,870**	**$ 428,999**
Average Debt (average of trailing five quarters):												
Notes Payable	**$ 452,812**	**$ 216,241**	**$ 327,683**	**$ 393,665**	**$ 312,522**	**$ 279,840**						**$ 285,012**
Long-term debt including current maturities	758,582	1,074,780	1,223,413	1,095,829	1,037,368	1,258,191						1,321,489
Total Debt	**$ 1,211,394**	**$ 1,291,021**	**$ 1,551,096**	**$ 1,489,494**	**$ 1,349,890**	**$ 1,538,031**						**$ 1,606,501**
Debt Ratio	**4.3**	**4.2**	**4.8**	**3.7**	**3.4**	**3.7**						**3.7**

Use of Non-GAAP Financial Measures

Depreciation, Depletion & Amortization, adjusted for Intercompany Capital Lease*

(in thousands, pre-tax)

YTD Dec. 31, 2014	Electric Utilities	Gas Utilities	Total Utilities	Power Generation	Coal Mining	Oil and Gas	Total Non-Reg	Corporate	Total
Depreciation, depletion and amortization (GAAP)	$ 79,424	$ 26,499	$ 105,923	$ 4,540	$ 10,276	$ 24,247	$ 39,063	$ (241)	$ 144,745
Capital lease adjustment	(13,072)	-	(13,072)	12,831	-	-	12,831	241	-
Deprec, depletion and amortization, as adjusted (non-GAAP)	$ 66,352	$ 26,499	$ 92,851	$ 17,371	$ 10,276	$ 24,247	$ 51,894	$ -	$ 144,745
Capital Expenditures	$ 193,199	$ 70,528	$ 263,727	$ 2,379	$ 6,676	$ 109,439	$ 118,494	$ 9,046	$ 391,267
Cap Ex to Depreciation Ratio			**2.8 to 1**				**2.3 to 1**		

YTD Dec. 31, 2013	Electric Utilities	Gas Utilities	Total Utilities	Power Generation	Coal Mining	Oil and Gas	Total Non-Reg	Corporate	Total
Depreciation, depletion and amortization (GAAP)	$ 77,704	$ 26,381	$ 104,085	$ 5,090	$ 11,523	$ 17,876	$ 34,489	$ (1,250)	$ 137,324
Capital lease adjustment	(13,100)	-	(13,100)	11,850	-	-	11,850	1,250	-
Deprec, depletion and amortization, as adjusted (non-GAAP)	$ 64,604	$ 26,381	$ 90,985	$ 16,940	$ 11,523	$ 17,876	$ 46,339	$ -	$ 137,324
Capital Expenditures	$ 222,262	$ 63,205	$ 285,467	$ 13,533	$ 5,528	$ 64,687	$ 83,748	$ 10,319	$ 379,534
Cap Ex to Depreciation Ratio			**3.1 to 1**				**1.8 to 1**		

YTD Dec. 31, 2012	Electric Utilities	Gas Utilities	Total Utilities	Power Generation	Coal Mining	Oil and Gas	Total Non-Reg	Corporate	Total
Depreciation, depletion and amortization (GAAP)	$ 75,244	$ 25,163	$ 100,407	$ 4,599	$ 13,060	$ 29,785	$ 47,444	$ (1,928)	$ 145,923
Capital lease adjustment	(13,044)	-	(13,044)	11,071	-	-	11,071	1,973	-
Deprec, depletion and amortization, as adjusted (non-GAAP)	$ 62,200	$ 25,163	$ 87,363	$ 15,670	$ 13,060	$ 29,785	$ 58,515	$ 45	$ 145,923
Capital Expenditures	$ 167,263	$ 45,711	$ 212,974	$ 5,547	$ 13,420	$ 107,839	$ 126,806	$ 7,376	$ 347,156
Cap Ex to Depreciation Ratio			**2.4 to 1**				**2.2 to 1**		

* PPA between Colorado Electric and Colorado IPP is considered a capital lease for GAAP purposes; this PPA went into effect Jan. 1, 2012

Use of Non-GAAP Financial Measures

ROE & ROA, as adjusted

Return on Equity, as adjusted											2015
(in thousands, except for ratios)	2009	2010	2011	2012	2013	2014	Q3 2014	Q4 2014	Q1 2015	Q2 2015	Trailing Qtr's
Income from continuing operations (GAAP)	**$ 77,269**	**$ 67,361**	**$ 44,374**	**$ 109,416**	**$ 118,308**	**$ 130,889**	**$ 27,363**	**$ 34,534**	**$ 33,850**	**$ (41,841)**	**$ 53,906**
Adjustments (after tax) -											
Interest rate swaps - MTM	(36,174)	9,875	27,306	(1,223)	(19,609)	-	-	-	-	-	-
Costs associated with prepayment of BHW project financing (net of interest savings)	-	-	-	-	6,577	-	-	-	-	-	-
Financing costs, net of interest savings ($250M bond payoff)					5,934	-	-	-	-	-	-
Asset impairment -Oil and Gas	27,805	-	-	31,899	-	-	-	-	14,412	62,894	77,306
Impairment of Equity Investments-Oil and Gas	-	-	-	-	-	-	-	-	-	3,360	3,360
Gain on sale of operating assets -											
- Williston Basin assets	-	-	-	(49,001)	-	-	-	-	-	-	-
- Sale of Elkhorn, NE service area	-	(1,708)	-	-	-	-	-	-	-	-	-
- Partial sale of Wygen III to City of Gillette	-	(4,055)	-	-	-	-	-	-	-	-	-
- Partial sale of Wygen I to MEAN	(16,881)	-	-	-	-	-	-	-	-	-	-
Incentive compensation - Williston Basin sale	-	-	-	2,605	-	-	-	-	-	-	-
Credit facility fee write-off	-	-	-	973	-	-	-	-	-	-	-
Make-whole provision, net of interest savings	-	-	-	3,011	-	-	-	-	-	-	-
Improved effective tax rate	(3,800)	(2,400)	-	-	-	-	-	-	-	-	-
Acquisition/integration expenses	3,439	-	-	-	-	-	-	-	(190)	499	309
Acquisition facility fee	1,873	-	-	-	-	-	-	-	-	-	-
Rounding	-	-	-	-	-	-	-	-	-	-	-
Total Non-GAAP Adjustments	(23,738)	1,712	27,306	(11,736)	(7,098)	-	-	-	14,222	66,753	80,975
Income from Cont. Ops., as adjusted (non-GAAP)	**$ 53,531**	**$ 69,073**	**$ 71,680**	**$ 97,680**	**$ 111,210**	**$ 130,889**	**$ 27,363**	**$ 34,534**	**$ 48,072**	**$ 24,912**	**$ 134,881**
Average Common Stock Equity	**$ 1,067,687**	**$ 1,002,928**	**$ 1,069,093**	**$ 1,157,689**	**$ 1,249,518**	**$ 1,321,542**					**$ 1,347,734**
Return on Equity, as adjusted	**5.0%**	**6.9%**	**6.7%**	**8.4%**	**8.9%**	**9.9%**					**10.0%**

Return on Assets, as adjusted											2015
(in thousands, except for ratios)	2009	2010	2011	2012	2013	2014	Q3 2014	Q4 2014	Q1 2015	Q2 2015	Trailing Qtr's
Income from Cont. Ops., as adjusted (non-GAAP)	**$ 53,531**	**$ 69,073**	**$ 71,680**	**$ 97,680**	**$ 111,210**	**$ 130,889**					**$ 134,881**
Average Total Assets	**$ 3,348,794**	**$ 3,167,588**	**$ 3,759,805**	**$ 3,736,213**	**$ 3,743,204**	**$ 3,974,623**					**$ 4,137,089**
Return on Assets, as adjusted	**1.6%**	**2.2%**	**1.9%**	**2.6%**	**3.0%**	**3.3%**					**3.3%**

Use of Non-GAAP Financial Measures

EPS, as adjusted

Earnings Per Share, as adjusted	2009	2010	2011	2012	2013	2014	Q3 2014	Q4 2014	Q1 2015	Q2 2015	Trailing Qtr's
Net income (GAAP)	**$2.11**	**$1.87**	**$1.34**	**$2.32**	**$2.64**	**$2.93**	**$ 0.61**	**$ 0.77**	**$ 0.76**	**$ (0.94)**	**$ 1.20**
Discontinued Operations	(0.11)	(0.14)	(0.23)	0.16	0.02	-	-	-	-	-	-
Income from Cont. Ops., (GAAP)	**2.00**	**1.73**	**1.11**	**2.48**	**2.66**	**2.93**	**0.61**	**0.77**	**0.76**	**(0.94)**	**1.20**
Adjustments (after tax) -											
Interest rate swaps - MTM	(0.94)	0.25	0.68	(0.03)	(0.44)	-	-	-	-	-	-
Costs associated with prepayment of BHW project financing (net of interest savings)	-	-	-	-	0.15	-	-	-	-	-	-
Financing costs, net of interest savings ($250M bond payoff)	-	-	-	-	0.13	-	-	-	-	-	-
Asset impairment - Oil and Gas	0.72	-	-	0.72	-	-	-	-	0.32	1.41	1.73
Impairment of equity investments - Oil and Gas	-	-	-	-	-	-	-	-	-	0.08	0.08
Gain on sale of operating assets -											
- Williston Basin assets (net of incentive comp)	-	-	-	(1.05)	-	-	-	-	-	-	-
- Sale of Elkhorn, NE service area	-	(0.04)	-	-	-	-	-	-	-	-	-
- Partial sale of Wygen III to City of Gillette	-	(0.10)	-	-	-	-	-	-	-	-	-
- Partial sale of Wygen I to MEAN	(0.44)	-	-	-	-	-	-	-	-	-	-
Credit facility fee write-off	-	-	-	0.02	-	-	-	-	-	-	-
Make-whole provision, net of interest savings	-	-	-	0.07	-	-	-	-	-	-	-
Improved effective tax rate	(0.10)	(0.06)	-	-	-	-	-	-	-	-	-
Acquisition/Integration expenses	0.09	-	-	-	-	-	-	-	-	0.01	0.01
Acquisition facility fee	0.05	-	-	-	-	-	-	-	-	-	-
Rounding	-	-	-	-	-	-	-	-	-	-	-
Total Non-GAAP Adjustments	(0.62)	0.05	0.68	(0.27)	(0.16)	-	-	-	0.32	1.50	1.82
Income from Cont. Ops., as adjusted (non-GAAP)	**$1.38**	**$1.78**	**$1.79**	**$2.21**	**$2.50**	**$2.93**	**$ 0.61**	**$ 0.77**	**$ 1.08**	**$ 0.56**	**$ 3.02**
Net income, as adjusted (non-GAAP)	**$1.49**	**$1.92**	**$2.02**	**$2.05**	**$2.48**	**$2.93**	**$ 0.61**	**$ 0.77**	**$ 1.08**	**$ 0.56**	**$ 3.02**

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CONSTELLATION NEWENERGY-GAS DIVISION, LLC

EXHIBIT SB-2

OF

STEPHEN BENNETT DIRECT TESTIMONY

IN THE MATTER OF THE APPLICATION OF BLACK HILLS NEBRASKA GAS UTILITY COMPANY, LLC D/B/A BLACK HILLS ENERGY FOR APPROVAL OF ITS GAS HEDGE AGREEMENT WITH BLACK HILLS UTILITY HOLDINGS, INC.

APPLICATION NO. NG-0086

Black Hills Corp

October 08, 2015
02:00 PM EDT

Jerome Nichols: Good afternoon, everyone. Welcome to Black Hills Corporation's 2015 Analyst Day, being held here at the Warwick New York Hotel in New York City. My name is Jerome Nichols and I am the Director of Investor Relations for Black Hills.

On behalf of our leadership team and everyone at Black Hills, I want to thank all of you -- those on the webcast, and particularly those here at the hotel -- for taking the time out of your busy schedules to spend the afternoon with us. We're really excited about today's event and hope you'll find our presentations informative and helpful.

Slide 2 of our presentation deck has our meeting agenda. Our leadership team will provide an introduction and strategic overview, business segment presentations, and a financial update. After the coal mining presentation today, we'll take a short break.

We will hold a question -- a quick question-and-answer session after each presenter. We will also have plenty of time at the end of the presentation for final questions. If you are participating by webcast today, you can ask questions through the chat feature of your web player.

Our presentation today includes forward-looking information and the use of non-GAAP financial measures. You should refer to slide 3 of the presentation, as well as our filings with the Securities and Exchange Commission, for some of the risk factors that could cause future events to differ from our forward-looking statements. A reconciliation of non-GAAP measures is available in the appendix of our presentation materials.

As a reminder, today's event is being recorded, and the transcript and an audio recording will be available after the event at our website at www.blackhillscorp.com under the Investor Relations tab.

Our first presenter this afternoon is David Emery, Chairman, President and Chief Executive Officer. Dave?

David Emery: Thanks, Jerome, and welcome, everybody. Also, thanks to all those of you who are participating by webcast. We appreciate your attendance as well. And thanks for being here. We've got a room full of people, it looks like, so we appreciate you being here today.

Couple of things we want to accomplish today. And, you know, we have these events every year. We kind of alternate where we have them. This particular one, I think, the last time we were in New York City -- we were talking about it earlier -- while we sat here this afternoon, two years ago, we had five feet of snow at home and a huge outage to go home to. So, we're glad that it's nice and not doing that at home this time.

But, similar to prior years, we'd like to go into a little more depth about our businesses at this meeting; hopefully share some new things with you, which if you saw our release yesterday, we -- we're going to share a few new things with you today, and we usually try to do that every year, and give you a chance to meet a little bit broader section of our management team rather than just the couple of us that you're stuck with for the rest of the year. So, hopefully give you a chance to ask some others questions, besides just the normal cast of characters here.

We've got an exciting -- you know, an exciting growth plan, and we're very excited about it. We've got good base growth. We add to that the SourceGas opportunity, and it's something we're really enthused about. Hopefully you'll get a better feel for what that entails today as we go through it. I think we've got an excellent track record of executing on these types of transactions, integrating them quickly and being successful with them, which I think bodes really well for the future.

Briefly, to introduce the group that's here -- and you probably know some of us but maybe not all. Rich Kinzley, our CFO. John Benton's our Vice President and General Manager of our oil and gas company. Mark Lux is our Vice President of Power Delivery. That includes responsibility for our coal mine and our generation fleet. Brian Iverson is -- a really long title, but let's call it Regulatory and Assistant General Counsel. And then Linn Evans, our Chief Operating Officer, Utilities. And then, of course, Jerome's here, and Kimberly Nooney, our VP-Treasurer, is here. She can answer questions as well.

Couple of things that you saw in the release yesterday, on what our topics were going to be for the day. Obviously the SourceGas acquisition -- we've made a lot of progress on a lot of fronts. I'll let Linn fill you in on all the details there, but we feel real good about where we're at, both integration planning and regulatory-wise.

Cost of service gas program is something we've been talking about for a couple of years -- really, more like three or four. You saw that in the last month we filed in five of our six states. We'll file in the sixth one soon, and we'll fill you in on that.

Obviously oil and gas is something that we've made a pretty major transition of what we're trying to accomplish there this year, and that is a much greater focus on utility cost of service gas and a pretty dramatic reduction in regular E&P spending. You know, at the end of the last quarter we announced we'd cut $200 million of normal E&P CapEx out of the two-year forward forecast, and we'll -- instead focused on cost of service gas.

The Peak View wind project is a project that's been working in Colorado for most of a year, with multiple iterations with the Commission. We have a settlement agreement reached there. It has not been approved, but we feel pretty good about where we sit, and we'll give you an update on that. That's a project that is not in our current capital forecast. So, that's an exciting new addition.

And then the Colorado IPP review -- we'll talk about that, but we've had some inbound offers and inquiries about that property, and we think we might be able to divest the minority interest for a very healthy number, and makes a lot of sense in the context of financing SourceGas and some of the other things we have going on right now.

I think most of you, if not all, are familiar with the company. But, you know, we're primarily now a utility. We do have coal operations and oil and gas; a little bit of non-utility power generation.

But, for all practical purposes, our power generation fleet and our coal mine are integral to our utilities. Oil and gas is the only non-utility business that I would consider we really have. And as I mentioned earlier, we're transitioning that to be a utility cost of service gas company primarily. So, we're really very utility-focused and have been working on that pretty hard for more than ten years now.

We talked about having four major goals and objectives from a strategy standpoint. And we've had these four for several years. Very straightforward. Everything we do revolves around these four objectives. And that's profitable growth; valued service; obviously, better every day, which is continuous improvement; and a great workplace. We think the energy industry workplace will continue to get more competitive for really good people as a lot of folks retire over the next few years, so that's high on our list, and keeping talent.

This slide speaks a little bit to what I talked about from an execution standpoint. But if you go back 11 years, basically, to early 2004, we really made a very conscious decision as a company to start focusing on what we thought we were the best at, of everything we do, and that is running utilities.

And we've done a whole series of transactions subsequent to that -- either acquisitions; generation build; some bigger projects on the transmission side; and a few other things. And then a series of divestitures that were all pretty well-timed in order to effectuate that strategy. And I think it's been very successful.

Some of the things we're going to talk about today kind of get to the end of that line there, when you see what the impact of the SourceGas transaction's going to be. But it's been a long, continuous process, but it's been very deliberate.

Several things. When we look at, you know, what's bright about the future here, and it's really all about the growth opportunity. And that's not just adding on SourceGas; that's talking post-SourceGas opportunities. We felt really good about our growth track record anyway. We have a very strong record of growing our utilities. We have pretty good service territories; very constructive regulatory environments, and have been successful in growing our base utilities.

We will continue to focus on acquisitions where they make sense. We've done a lot of small tuck-in acquisitions, if you will. We'll look for the big ones, but they have to make a lot of sense for us. When you have to pay the multiples that we paid for SourceGas, you have to see a lot of opportunity to improve the business jointly as you combine those entities to really make that work. That one, we saw that opportunity.

Some of the other big ones we'd looked at in the couple of years prior to that, we didn't see that much opportunity, and we didn't buy them for that reason. So, we'll continue to focus on that. And then our organic growth in our base utilities -- we're going to really work on that; continue to make that a focus.

Technology is something, and we've talked about it a little bit in the past, but we're doing everything we can to keep costs down for ratepayers. If we can utilize technology and decrease ongoing cost to customers, that's a win-win. We make the technology investment for the shareholders; we save money for customers. We've had a lot of focus on improving our operations through automation and things like that.

Generation and transmission are things that we do a lot of. You've seen our track record there, where Mark and his group are fantastic in building power plants on time, on budget; or usually, ahead of schedule and ahead of budget. Something that, as we have continued justification, and we will, we'll continue building projects and growing our business through that, and transmission as well.

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.

The SourceGas transaction -- you know, I'll let Linn and others talk about the details of the transaction. But one of the things I mentioned earlier is that, you know, we think we're pretty darn good at integrating utilities.

When we did our Aquila transaction in 2008, we did seven major systems conversions in a little over two years. And we were very deliberate in what we did. We picked platforms that not only worked well for the combined Aquila/Black Hills entity, but also platforms that we knew we could easily add a lot more customers onto without having to go through that process again. So, the acquisitions that we've done subsequent to then, we've literally just bolted all of those directly on our systems and processes. It's been very efficient.

The last one we did is an example that's a little smaller than SourceGas, but the process is the same. We purchased Energy West Wyoming July 1st. Only about 7,000 customers, but we had them fully on our systems -- everything from payroll, to accounting, to human resources, to customer information services -- on day one of closing. Phenomenal accomplishment. Process is the same to do that whether it's 7,000 customers or 700,000 customers.

We probably won't be able to do SourceGas quite that fast, because we have four states to convert all the customer information and tariffs and everything else; but we think we can do it very quickly. So, it's a huge advantage for us.

But in this environment, I mean, there's been a lot of things kind of acting -- impacting our business, I guess, if you will. Certainly the interest rates have had an impact on the whole sector, us included. But oil and gas prices have had a pretty big negative impact on us.

And as I said, that being our one kind of market-exposed business, it's hit us pretty hard. You look at the operating losses at E&P this year, and they're not good. You know, we've had a non-cash impairment of our reserves, and likely we'll have more as the year goes on. But, from a strategy perspective, I think we've remedied that for a go-forward strategy, and really focusing on cost of service gas instead, and it really kind of gets us out of that very heavy dependence on product prices.

The repositioning here, I already spoke about. But it's an area where, with our Mancos shale gas play, we think we have a huge resource, way more than we will use even for cost of service gas. And we've got a lot of testing under our belt here, and John'll talk about that. But with a few years of drilling -- and we've learned a lot about that play, and we think we can really transfer it into a very successful program for gas procurement for utilities.

From a stock performance perspective, obviously the last year hasn't been too good to us. Prior to that we've done very, very well, and I think we've got a great long-term track record, and a very bright future. Certainly our dividend track record is one of the things we're very proud of -- I think the second-longest streak in the utility industry for consecutive dividend increases. So, all in all, overall returns still look pretty good despite the big downturn in oil and gas over the last few years.

I think all of these things, I've already spoken about, so I won't reiterate them again other than to just say, we have a lot of exciting things on the plate for the future here, and you'll get a lot more detail from everyone else, and I'll let them fill you in on what those are and add a little color to it that I have skipped over. So, with that, I'll introduce Linn Evans, the President and COO of our utilities. Linn?

Linn Evans: Thank you, David, and good afternoon. For those of you on the webcast who may have a printed document, I'm going to start on what I think is slide 19 in the deck, at least. And I will talk about the utilities at a more specific level than Dave did. And then, after I'm finished, Brian Iverson will step up and talk about cost of service gas now that we have those filings in place, and the regulatory lift that we have there.

As Dave indicated, we have four categories of goals: profitable growth; valued service; better every day; and a great workplace. Not only do -- does that help us communicate our strategy externally, but it's very important for how we communicate our strategy internally, ensuring that we have our employees aligned with us and everything that we do.

We have goals down to the individual throughout the organization. We use that as part of our annual performance management process, and it's also an important part of our incentive compensation to ensure that we're all aligned for shareholders and customers alike.

We have, of course, many growth opportunities, as Dave has already suggested. We'll drill into those more independently as we go through the presentation. But valued service is something -- maybe stop and talk about for a minute, before we go into the growth items. We really strive to be top-quartile in everything we do, particularly with respect to operations, customer service and reliability.

We think we are doing that, and we're focused on continuing to improve. We're very focused on our relationships. Relationships are important to us, particularly with our customers; our regulators; our government entities; and importantly, the communities that we serve every day.

And as an organization, we're very focused on having a strong compliance culture. That's really important to us as an organization in terms of our values, and our employees know to do the right thing every day. And that impacts our relationships, obviously, with our regulators and our customers.

A great workplace is very important to us, as Dave has already suggested too. We're retiring a lot of people from this industry, including our own company, and we're working very hard to make sure that we can attract the best and the brightest to our organization.

Engagement -- employee engagement's very critical to us. We measure it. We measure it on a consistent basis. We put plans in place each year to help us continue to maintain the high-level engagement that we currently enjoy, and continue to improve upon it.

And we want to be one of the safest energy companies in the country. We're very serious about that goal. We've made great progress with respect to our safety performance over the last number of years. We have about 2,000 employees. We said today about 9 reportable incidents out of 2,000 employees. We're not world-class yet, but we're sneaking up on it and getting there as quickly as we can.

You've seen this slide before if you're familiar with our organization. It gives you an idea of our footprint for our electric utilities and our gas utilities, and the number of customers that we have in each.

If you look at the map for the natural gas utilities, you see new jurisdictions that we've already talked about a little bit: MGTC and Energy West. So, you see a little bit larger footprint in Wyoming. And of course SourceGas is going to add to that, and we'll talk about that in a few moments.

But I'm very proud of the team and how they performed with respect to integrating these this year. We are fully integrated on day one on our systems of billing, taking customer calls, et cetera. So, our team's done a phenomenal job of incorporating and integrating those two new utilities.

We thought this might be helpful to show you at least an economic indicator of the jurisdictions that we have the privilege to serve. Four of our seven states are in the top ten with respect to the lowest unemployment, and all seven of our current states that we serve happen to be in the top 20. So, good, decent growth within our -- the territories that we serve.

We work to give you more clarity and more detail, if you will, with respect to our capital investment. You can see that we've given capital investment back from 2011 through 2017 forecast. We've divided those into generation, transmission, and distribution, and other category.

We've also worked to give you an idea of what kind of riders we have with respect to capital investment, that essentially allows us to have a immediate return, eliminating regulatory lag as best as we can with respect to those investments. Now, this chart -- table does not include SourceGas; nor does it include our recently-announced Peak View wind project.

Growth through acquisitions. Very important to us. Obviously I'll drill into the SourceGas acquisition in a few -- in a couple more slides. We're also focused on what we call organic growth -- growth within our own utility, encouraging customers to use natural gas who may not; or convert from propane, et cetera; compressed natural gas stations -- things of that nature.

We have three different horizons that we look at: the near term, the mid term, and the long term. And then we have very specific goals that we have within the organization with respect to adding what we call Residential Meter Equivalents. That's essentially the amount of annual margin that we get from a typical residential customer in a given year.

And we don't just look to add revenue or margin. We put all of our investments in all of those customers that we seek through a financial analysis, to ensure that we're not just adding revenue but we're adding value for shareholders, and holding ourselves accountable to those models. And really, what we want to do is grow faster and more aggressively than the average utility in the US.

And we've had some track record with respect to that. This gives you an indication of our customer count and the volumes of usage. These usage -- these volumes are not weather-normalized. So, you can see in 2012 we had a pretty mild winter -- you might recall that -- with usage kind of rebounding from that point.

We're seeing our customer growth approaching 1%. And we're also seeing volumes at about 2%. And we're seeing an increase, as the chart indicates, in our electricity demand. I know there are some parts of the country that it seems to be a challenge, but for us it's not. In fact, we enjoy trying to keep up with it, to be frank.

SourceGas. A very exciting transaction for us -- one that we have looked at, frankly, for -- over the last five years. When the opportunity came, we took advantage of the opportunity to acquire SourceGas. We announced the transaction on July 12. It was for $1.89 billion. We do have $150 million of tax benefits which effectively lowers that price to $1.74 billion. And included in that is a $200 million, roughly, reimbursement for capital that SourceGas will spend by the time that it is closed. And the transaction, of course, also forecasts that we will absorb $720 million of debt.

The strategy -- this acquisition fits extremely well with our strategy. Later on I'll show you a slide of the footprint. You see how it fills in, very nicely, three of the four states that we serve, including the addition of Arkansas.

We're adding -- I don't know if it's (ph) 55% growth in our customer count. About 60% of those customers are in states that we already serve and territories that we already serve. And we believe this transaction -- we're working very hard to make sure it is meaningfully accretive to EPS in the first calendar year after we close.

Regulatory approvals are moving well. We have received Hart-Scott-Rodino antitrust clearance. We received that on August 18. And I'm very proud of the -- how hard our team worked to ensure that we filed approval applications very quickly and very efficiently in the states that we have applied for approval.

In fact, we announced on July 12. By August 10, we had filed applications in all four states. In each of those applications we requested a March 1 approval date. We have procedural orders in two of the states, Nebraska and Arkansas, that have hearings for January 12 and January 7 respectfully. And we are now currently seeking and working on procedural schedules in both Colorado and Wyoming.

We feel that, if we're fortunate enough to get settlements in all four states, it would be very easy for us to have a March 1 approval date for the transaction.

Discovery is ongoing. As you can imagine, in four states it's a lot of activity. We've had over 330-plus data requests. We have thoroughly -- we have responded to more than two-thirds of those, serving those on time. Usually you have a -- maybe a ten-day response time; sometimes as short as five. We worked very hard to respond on time, because we want the schedule to keep moving at a pace that we would appreciate, and give no reason for the regulators to slow us down, if you will.

We're working very hard on integration activities. We're integrating in four states and 425,000-plus customers into our system. The good news is, from our perspective, we've done this 19 times in the last ten years. We feel we're pretty good at it.

We don't want to get too big for our britches. Things can go wrong very quickly; but we have confidence in our processes, and the procedures, and frankly the leadership team, and the people we have working on these acquisitions. They worked on all the others prior to this one. We have about 15 different teams of people led by people who has led, frankly, these last 19 acquisitions. So, this is number 20 through 23 that we're working on now.

Confident in their abilities, and what they're doing. Working very hard. And things are going well, and essentially on track to where we want to be at this point in time. And importantly, we will be migrating all of SourceGas's datas and processes, as Dave indicated, onto our systems. So, this will be a fully-integrated utility.

The map says a lot in terms of the transaction for us. You can see the three states that we already serve -- how it's a great fill-in opportunity for us with respect to being a more efficient utility, and a utility with greater scale, as we move to 1.2 million customers. So -- and I think we -- customers are going to greatly benefit from this transaction.

We see SourceGas as having great growth opportunities. SourceGas itself has grown at 2% annual customer growth. We expect that to continue. They have processes and procedures that are very focused on growing a natural gas utility. We're excited by those. We think they will enhance our own processes and procedures with how we see growing a utility.

And interestingly, they use RMEs as their own measurement as well. So, they anticipate adding 11,300 Residential Margin Equivalents annually. They have extremely good or very good fuel conversion programs, converting other fuels like propane, et cetera, to natural gas.

They also have good programs and processes that allow them to aggressively go after agriculture, particularly poultry customers. And then some very good tariffs with respect to main extensions allow us to continue to grow the system. And it's going to bring to us pipeline and storage investment opportunities that we haven't had before.

And then finally, as Brian will talk about later, we do see a good opportunity for a future cost of gas service -- cost of service gas program, and the potential there with the acquisition.

And in fact, I mentioned, we're already in three of the four states, but we're adding Arkansas. We've learned a lot about Arkansas over the last several months and we're excited about that state. Fayetteville will be a town that we will serve. It's located in Washington County, Arkansas. We are informed that that's the seventh-fastest growing county in the US. So, great growth potential there, and we're very excited about that.

SourceGas. Much like ourselves (ph) -- like Black Hills, does have a constructive regulatory environment. You can see some of the cost recovery mechanisms that are in place, very similar to those that we have in our territory, so that's going to match very well with Black Hills.

And then transitioning back to growth. Growing through efficiency. As our population in our organization -- our employee population ages, we see great opportunity for us to invest in technology, and we've been doing that quite aggressively as an organization.

We see it as an investment that allows us to lower our pass-through costs and our O&M costs by investing capital, which means it's a win for the shareholders and a win for the customers as well. We put these programs through rigorous financial models and then we check on ourselves constantly to make sure we're getting the returns that we anticipated. If we're not, we make adjustments, and when we are, we're very happy about that, obviously. It also helps us lower our costs.

We were focused kind of in three categories: customer service, our grid, and our field operations. We focus on our customer operations -- lowering our customer service cost, while making it easy to do to business with us. So, our customers see the opportunity to improve how we do business with them and how we interact with them, while we lower our cost.

Improving reliability's important to us. Our AMR and our AMI, particularly, help us with that.

And then, most recently, we have been putting technology into the hands of the field employee. We have launched hundreds and hundreds of iPads. Every employee has iPad in the field, with all the data they need to do their job well. And we've also used that data and that information to improve how we dispatch employees -- much more automated. So, our field knowledge is better. Our efficiencies in the field with how we use labor and how we use equipment, has much improved. As you can see, some of the dramatic improvements in our performance of late.

We're always interested in building new things, particularly generation, transmission, pipelines, et cetera. These are some of the few examples on slide 32.

I will drill into the Cheyenne Light, Fuel & Power and some of the Colorado Electric stuff; but let me touch on the Black Hills Power transmission line before I move forward. We are working to construct a 144-mile, $54 million electric transmission line that's essentially a transmission line that will help us with reliability after having closed a couple of our older coal plants. That line should be in operation by mid-2016.

Looking at Colorado Electric on slide 33, we have two great growth opportunities. The first is one we're already working on. That's the 40-megawatt, $65 million natural gas-fired combustion turbine that we are currently building at the Pueblo Airport Generation Station. It's essentially a plant that will replace the W.N. Clark plant, which was a coal plant that we retired a couple of years ago, located in Cañon City, Colorado.

That construction and that project is on time and on budget. It represents our 19th project in about that many years. And it will be commercially operational the fourth quarter of next year, so I'm very proud of our team and what they're doing there.

We just recently announced a settlement agreement that we filed on September 24th with respect to our Wind Peak wind project. Colorado has a renewable energy standard of 30% by the year 2020. This gets us along that path of complying with that renewable energy standard.

As I said, we filed the settlement agreement with all intervening parties. The Commission, we anticipate deliberating this month. We hope to have an order next month. And the project will be purchased from a developer. It represents a $109 million investment if you include our interconnection cost and our AFUDC.

Cheyenne Light. Cheyenne continues to be a bright star in our portfolio of jurisdictions and utilities. It's growing quite rapidly for us. In fact, this year, this summer, Cheyenne Light set three peak records consecutively, with pretty doggone mild weather for Cheyenne. So, weather was not a big impact in demonstrating the load growth that we are seeing there.

And Microsoft happens to be one of the leaders with respect to growing that load for us and with us. To date, Microsoft has committed about $500 million of investment in data centers. They have announced another $250 million in investment -- will take their total investment to $750 million.

We're going to serve that load in a couple of different ways, being creative with Microsoft to encourage them to continue to grow and develop, while making sure that we have good returns for our shareholders. So, the first 35 megawatts of load, we're serving under a normal, or currently existing industrial contract services tariff. After 35 megawatts, they -- anything in excess of that will be served under a new proposed, what we call large power contract service agreement tariff. We filed that tariff on October 1 and we anticipate and hope that it will be effective by January 1, 2016.

Along with this growth and the investment that they make in terms of infrastructure, we're making our own infrastructure investment as well. As you can imagine, substations and transmissions, et cetera. So, it's a very good, and great opportunity for us at Cheyenne Light.

This slide attempts to combine all three of our electric utilities -- give you an idea of our capacity and our current energy demand, and where we forecast that it's going. You can see in the base load -- we've closed a number of base load plants, particularly coal plants, the last couple of years. So, we do see, hopefully, some opportunity in the near future to begin to fill in that base load capacity that we are now short. And these are not weather-adjusted, these are actual peaks, by the way.

And then, now, moving into the regulatory arena, before Brian comes up. We've shown you this slide before, but we have worked hard within our regulatory relationships to provide pass-through mechanisms that allow us to eliminate, as best we can, regulatory lag within our utilities.

Now, Brian's going to come up and talk about -- well, I think that I'm supposed to stop -- slow down and ask if there were questions first. So, any questions at this point, before I run away? Mike.

Unidentified Participant: Thanks, Linn. With regard to the $600 million of long-term pipeline safety and integrity investment that's gas source, how much of that is -- has been approved, or what is the process of getting that approved if it's not?

Linn Evans: I'm not aware that any of it has been approved, Michael. It's all capital investment that primarily SourceGas management has identified. We're reviewing it now. We think it looks -- you know, very legitimate capital opportunity. And it would be capital investment that we believe would largely be through riders and tariffs that they have in place over the long term. So, we're early in that process, and clearly identifying that what we see looks very legitimate and will be a good investment for us going forward.

Unidentified Participant: I don't (inaudible) Brian or not, but when are the right points for settlement discussions to take place in SourceGas? And, if you do not have four settlements done, what are the odds that March 1st slips (inaudible)?

Linn Evans: The question was, what are the -- what kind of -- what's the process procedure with respect to settlements in SourceGas, and what's the prospect of maybe a March 1 date slipping?

We think the prospects are quite good, particularly in the states that we've talked -- we've met on a number of opportunities and times with the Commissions, and with staff, with interveners including Office of Consumer Counsel. They know us, in three of the four states. They know us well. And we anticipate that we will use those relationships that we have now to continue to talk to them about settlement.

In some states the word has already come up, and so we're beginning to have those discussions, if you will, already. It's very early in the process. We're -- still owe them responses to some data requests. They tend to like to get those in place.

But we feel pretty good, subject to anything that might come along and surprise us with respect to getting settlements in all four states. And we are very focused as an organization on the March 1 closing.

Unidentified Participant: Do you need to go through hearings, or what's the protocol in the different states, as far as where you've seen settlements (inaudible)?

Linn Evans: The question is, do you go through hearings when you have settlements? The question is, oftentimes yes. They tend to be abbreviated hearings. So, usually the --

Unidentified Participant: Do you have to have the hearings before you can move to the settlements --

Linn Evans: Oh, I'm sorry.

Unidentified Participant: (Inaudible) states (inaudible) settle before the hearings?

Linn Evans: The question -- let me clarify. The question was, do we have settlements before the hearings or after? The answer would be, before the hearings, in all those states. We hope that the hearing would be essentially turned into a settlement hearing.

Unidentified Participant: If the Peak Wind project is approved by the Commission, would that be in a rate case early next year for implementation, I guess, late in '16, for Colorado?

Brian Iverson: Rate case timing.

Unidentified Participant: Yes.

Brian Iverson: This is Brian. That -- the settlement agreement in that -- so, this is public record -- works to pass the cost associated with that wind farm through, in Colorado, the ECA, and through our renewable energy rider. And so, all the costs get passed through on the rider. So, no rate case involved with putting that $100 million investment into service.

Unidentified Participant: And then when you're talking about future load and capacity -- I guess, capacity shortfall -- would the expansion of the Cheyenne Prairie Generating Station be one of the major potential expansion opportunities?

Linn Evans~~Brian Iverson~~: It could be very possible, yes. We have plenty of territory -- land, if you will -- to expand upon. And we have air permits in place that we could use if we chose to.

Jerome Nichols: We had a question from one our webcast participants. And the question is, can you explain the $150 million of tax benefits that will lower the effective price of SourceGas acquisition?

Rich Kinzley: Yes. This is Rich Kinzley. I'm live here? You can hear it?

Unidentified Participant: Yes.

Rich Kinzley: Okay. What that is -- it's a combination of two things. But it's the net present value of net operating loss carried forwards as part of the acquisition; and then additionally, we get to do a step-up on part of the acquisition. So, the tax benefits derive from both of those, creating that present value of approximately $150 million.

Jerome Nichols: Any other questions? All right.

Brian Iverson: Okay. Thanks, Linn. Good afternoon. Going to talk a little bit this afternoon about cost of service gas. It's something we've been talking about, and really made some good progress here, then, in the last month, of taking the next steps towards doing that.

We've spent the last couple of years really looking at the process, looking at what other people are doing. We've had about 18 meetings with the different consumer advocates, Commissions, Commission staff, and people -- other stakeholders in this.

And that all culminated, then, in September 30, of us filing in five of the six jurisdictions. ~~at~~ Colorado~~.~~, ~~W~~we had some ongoing docket activity going on, and so have -- delaying that till later in the month. But, once again, those are all ready to roll and the filings will be made and completed by the end of October here.

So, what the contract -- what the filings really cover, just to kind of give you a little bit of color and background on how this works, is a -- really, a prepackaged set of determination of, how does the relationship work between a non-regulated affiliate that's going to own the resources, and the utilities that are going to basically get the benefit of the resource?

And so, what we've done is provided new tariffs for the Commission to review. We've provided mechanisms on how we would transfer property into that and set up a more timely process to go through, with a 60-day window to, once we identify a property and have it turned in to the Commission, for there to be an approval process, so that we can move assets into that. Those assets could include some of our Piceance Mancos assets could include some third-party assets too. So, it's really made generic filing, to basically be able to provide the ownership of rate-based reserves for the benefit of customers.

Just to go a little bit further, in our case it's a non-affiliated provider. It's going to be owned by Black Hills Utility Holding Company, which is the actual holding company of our utilities. And the reason you do that is, there's tax benefits that you get from having it not being fully integrated in with the utilities.

The other practical benefit is, as you look at the utilities themselves, they're each going to have a fractional interest in what might be there. And so, it's just a lot easier to own it under one entity and then divvy it up under contract between the different utilities.

The other piece of our filings that we think is unique is, unlike a lot of utility companies, we've got 30 years of experience in the oil and gas business. And I think, when we've been having these conversations with our regulators, that's been something that you kind of wonder how they'll take that, because we're in the business -- you're in a utility business affiliate; questions always come up.

But they've really seen that as a positive view, in that we know what the business is about; we know how it operates; we understand the financials behind it; we understand the operations behind them. So, that's been a positive.

The other piece about the filings -- when you look at the long-term cost of gas, we all are -- have been exposed to what happens in the market. Long-term, we believe that this is going to provide more stable prices, and what a better time than right now to actually start getting into that program for the benefit of customers?

So, it's really a win-win in that you provide a stability of cost for customers, but also provide a great investment opportunity for utilities. You know, in particular, gas utilities, you've got integrity investment; you've got other things. But growth has been on the slower side. This is a great opportunity to really pick up that growth and provide more earnings potential out of a gas LDC. And we're also going to use it for part of our electric generation too. So, any of our gas fuel generation,~~.~~ ~~A~~and of course, with 111(d) and other items pushing out there, it's going to create some great opportunities in that respect.

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.

So, just looking at some of these things here -- the filings propose that we put the resources in, and it's for the life of the well. So, these are 20-plus-year-type arrangements that we'll get into these programs. We're going to submit a billing -- a drilling program to the Commissions as part of this process, which will be approved.

And once we get that, every five years we'll go and file a new drilling program to tell them what we're going to be up to. So, it really kind of gives them an idea or a runway of what kind of capital costs and what kind of expenses they should expect.

When we look at the financial aspects of this to the company itself, we're going to target 50% of the demand, and we've got a slide a little later on that covers what that is, and we'll talk about it a little more. We're going to use the cost of debt -- typically it's going to be our -- we finance at the corporate level, so it'll be the corporate cost of debt. If we have any specifically-identified financing for this particular entity, that will be blended in there.

The capital structure -- what we propose is a 60% equity capital structure. We think that that is kind of a hybrid between what a utility capital structure would be, and an E&P-type structure. And so, it appropriately matches the kind of credit quality that you want to get out of this process.

Then, as I mentioned, the recovery mechanisms are through ECAs and the GCA. So, it's contemporaneous filing. We file those anywhere from every month to twice a year in the different states, depending on what the jurisdiction, and -if it's gas or electric.

Jumping over to the right a little bit on that slide, we want to talk about the allowed return. What we've done is, instead of, as you might be familiar with in a typical rate case, you have expert testimony and you talk about equity returns a lot. And what we've done is try to make this a streamlined process, since it's going to be flowing through ECAs and PGAs, to really go back and look at the last 20 approved rate cases across the US, both gas and electric, and use the average of those to determine the cost of equity for this program. So, that will be the number.

If you did that today, it would be approximately 9.86% ROE on it, if you just did it today with the ROEs that have been out there, in the -- you know, the lower interest rate environment that we're in today.

The other piece of the return that we have built into this is kind of an incentive mechanism. So, to the extent that customers are getting a bill -- a credit on their bills as part of this PGA/ECA, we have the right under the contract to earn basically an extra 100 basis points.

So, instead of using that 9.86% that we talked about, it would be a 10.86% return. And that would adjust, you know, depending on what the -- what that allowed return is every year. By the same token, if the customers are seeing an adder (ph) onto their bill because of the program, we would then reduce the ROE for that piece of it by 100 basis points.

So, it really kind of provides that incentive -- makes it -- gives the regulators comfort with how the program's operating, that we're going to be motivated to do this in the best possible way. Gives us an opportunity, certainly in higher market environments, to actually enhance the return for this entity.

The other thing that we propose to help give comfort to the regulators is just third-party oversight. So, we're going to have hydrocarbon monitor, which is really the engineers, that would weigh in -- and this is particularly important in the process of when we're going to transfer reserves in.

That's -- hydrocarbon monitor would review it; validate our information, which then gives us that shorter timeframe for Commissions to approve the addition of reserves into the program. And then, of course, an accounting monitor, which goes through and helps audit and verify any of the filings that we would make, both the financials on the -- related to the engineering reports, but also in regards to the regular pass-on products.

You go on to this, and you've seen this slide before from us. There's a lot of other places that this is being done. It's -- certainly, with all the discussions we've had with the regulators, there hasn't been any questions that say, you know, this is really, really unique -- are you sure it's going to be work?

There's all kinds of -- whether it be down in Florida; Northwest Natural out in Oregon has done this; the -- LA Power and Water's been doing this for probably a decade. And so, there's a lot of precedents for owning resources for the benefit of your customers, to give them that long-term hedge.

Then, just gives you kind of an idea of the quantity that we have. This is based upon 2014 actual. You know, you'll notice this can go up and down as it goes along. About 75 Bs is our actual gas supply. And what we've proposed in the filings is that we would use -- we're suggesting that we work to get up to half of the supply through this program. And so, that's that 37.85 number you see on there.

So, to give you an idea of an order of magnitude, you know, one of the assets we've talked about transferring over into this, or using it -- this is the Mancos. You know -- and the other piece you look is that 37 Bs a year -- if you look at the potential resource that we have in the Mancos, still leaves plenty of other resource out there. That's just a fraction of what -- the resource we have in the Mancos itself. So, to look at, can you do this program; how do you get it done, there's plenty of gas out there to make it work.

And this last slide -- just to kind of an idea of -- you know, you've seen the history, and certainly back in that 2006, 2007, 2008, when everybody was looking at $20 gas prices, the technologies are -- $20 natural gas prices, that technology has certainly come down, and the shale gas formations have really been exploited to the point where they've made it much more efficient. But we still look to see that. Absent a program like this, you're going to see, you know, history kind of repeat itself.

And the goal through our cost of service gas program is to provide something more like the right-hand side of that slide there, to provide more stable prices for our customers; but also to give a great investment opportunity for the utilities.

I think what we've said in the past is, we've estimated, you know, between $1 to $2 per Mcf of investment opportunity for what we would supply here. So, with that, I'll take any questions that you may have, and -- Nancy?

~~Unidentified Participant~~Nancy Doyle – MetLife: How do you decide what assets to buy to put into this program? Do you have to justify that your -- say, your Mancos assets, are the cheapest source? Because there must be lots of assets for sale, to go into this program.

Brian Iverson: Yes. So, there are criteria that we have in the contract between the utilities and the cost of service gas company, that talk about the kinds of properties that we've looked for. And they've got to pass some financial tests. Okay? So, the PVs of the reserves and the cost of drilling and things like that, has to be -- meet certain criteria.

But as we look at that, we also look at -- one of the advantages is that we're going to own it and have operational expertise over the property. So, we typically would favor properties that we're going to own and operate in this context. And certainly the cost of service gas company isn't (ph) going to own anything. It's not a program which we take a working interest in, and apply that. There are other programs that work like that. That's not what we propose. So, there are financial metrics that we'd have to meet (ph), is the short answer. Chris?

Chris Turnure: Chris Turnure, JPMorgan. I just wanted to get a sense, if you in fact do it with your own properties, how do you determine the -- essentially, the cost of the asset itself? Is it just book value that's depreciated over time, and that's the return on capital?

Brian Iverson: It would be a formula that we use to -- basically, an evaluation with, you know, engineers and a financial present value. You know, it's a future (inaudible) kind of cash flow kind of analysis that we do. So, it wouldn't necessarily be the book value on our -- of our assets.

Chris Turnure: Okay. And can you talk a little bit more about the timing of hopefully getting approval in all six states here?

Brian Iverson: Yes. Thanks for that. So, we filed on September 30th. We'll be filing later this month. If you look, you know, reasonably, it's an eight- to ten-month process.

You know, I would hope that, as we look in the mid of next year, we're getting to the point where we're -- I would expect in the second and third quarter of next year, we're talking seriously about settlement, and really, they should understand the program and get it to that next point, so we have approvals in the third quarter.

We do have about $50 million of capital in our forward capital plan for next year, to deploy in this program, if you look back at the slides that Linn had; and also $100 million in 2017. So, we expect to get going on this in the third quarter (inaudible) next year.

Unidentified Participant: With respect to including your Mancos assets in the program, do you think regulators see advantages to that coming out of the gate, or are they going to be looking at that on a level playing field with whatever other assets may be available?

Brian Iverson: That -- I think -- you know, certainly, we -- and John will get into this a little more. We've got a lot of experience and understand those assets fairly well. And so, it's going to get into demonstrating the financial model around those assets, and if they make sense to put in, I don't think there'll be issues there.

But we haven't -- we also haven't closed our eyes or our vision to, you know, looking at other things that make sense in that. For us, you know, it's an opportunity to invest capital from the utilities perspective. Where that capital is invested, as long as it goes through the process and we get recovery on it, we really should be indifferent.

Jerome Nichols: We have a couple of questions from our webcast participants. The first question is, what percentage of annual gas supply is currently under long-term contract?

Brian Iverson: Under long-term contract, we don't have any.

Jerome Nichols: Very good. Second question is, you mentioned that one of the benefits of cost of service gas model is, that can help stabilize prices. Do you see -- foresee much price instability in natural gas in the coming years?

Brian Iverson: That's the, what, $62,000 question. You know, you guess -- you don't know about it until they come across it. If you look at some of the market forces out there, certainly the drilling technology's getting (ph) great. These shale plays have become -- it's not a matter of, if there's gas; it's more a matter of, how do you most economically get it out?

But you look at things like 111(d) -- the transformation from a coal generation fleet to a gas fleet. I think that's going to have significant impact. You do see -- so, I think most forecasts show a pretty steady, slight uptick in the forward cost of gas. But I think if you look at every forecast, it's right until the next day, and then it's wrong. So --

Jerome Nichols: All right. One last question. Your -- it says, your slides show cost of service gas CapEx of $100 million in 2017. If and when the program is fully implemented, is it fair to think about it as $200 million annual capital expenditures, 60% equity, and low double-digit return on equity?

Unidentified Participant: $1 to $2.

~~Brian Iverson~~Rich Kinzley: Yes. What we've been talking about's $1 to $2 per Mcf. And you can see the -- 50% of our demand's in that 35 Bcf range. That would be kind of the ongoing CapEx, probably. We would have to spend a little more on the front end, more than likely, to get built up to that level of production.

Brian Iverson~~Unidentified Participant~~: But that rate base model of how you would analyze what kind of income you'd get off of it, would be accurate?

Unidentified Participant: 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?

Brian Iverson: 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 the entity that's doing the drilling, and owning the reserves.

Unidentified Participant: 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)?

Brian Iverson: 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.

Unidentified Participant: So, that would all get loaded into the cost of the program.

Brian Iverson: Right (ph).

Unidentified Participant: So, the -- like, a bad well gets sucked in and spread out over everything else.

Brian Iverson: Right.

Unidentified Participant: So, you guys don't carry exposure to that.

Brian Iverson: 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.

If it were a different kind of structure -- say, like the Questar model that they've got, which has got a higher return but there's some dry hole risk and things like that in that program. So, what we try to do is match up the business risk profile with the returns we'd ask for out of the program.

Unidentified Participant: At the $1 to $2 per Mcf cost of -- capital cost, going into this.

Brian Iverson: Uh-huh. Correct.

Unidentified Participant: What do you guys estimate is the delivered cost of the gas under this construct, if you look at, you know, drilling programs and further expansion on what you guys have? (Inaudible).

Brian Iverson: Yes. I don't know if we've talked about that. But maybe, Dave, you want to --

David Emery: Yes. You know, we've talked a little bit about it, Dan (ph), and said, you know, if we look back at our historical cost of gas delivered to utilities, and even in recent -- like this year, when that price is relatively low, it's not a spot price. Right?

So, you know, our real bogey is, we've got to be in that probably $4 to $4.50 range; maybe as high as $5. But, you know, you have to be at that number or really less, in order for this to really be a good, long-term, viable deal for customers. And those are the kind of numbers we've had conversations with our regulators about.

You know, look back at, what's the actual all-in delivered cost of gas for our utilities today? We buy gas in three ways for our utilities today. So, roughly a third of the gas comes from open market purchases, which sometimes can be awful expensive. A third of it comes from seasonal storage. And a third of it comes from financial hedges that are typically one year ahead. And the weighted average of those runs in that kind of a range, as far as what we're actually charging -- what the actual cost of gas is to our utilities. So, if we're in that range, we don't think we'll have a lot of challenges with this program.

Brian Iverson: And we've had that discussion -- you know, the bogey here is not the NYMEX cost, because customers pay more than that today, and we've had those specific discussions with regulators. So, what you get at is our -- regardless of the market conditions, they're going to pay the cost for this portion of their gas supply.

So, if it's $4.50 and gas is at $6, they're going to get $1.50 credit for each Mcf that they might have to buy. And if they're buying that for $6, it takes it back to $4.50.

David Emery: And that's the other thing that we've said about this going forward, is this piece will largely replace a lot of the hedging and the storage pieces of this, and some of the open market purchases. So, we'll probably have a little storage left, a little open market purchases, and maybe some hedging, but not a lot, depending on the state. And this is going to be the big, stable piece that would replace some of those other mechanisms that we use today.

Brian Iverson: Remember, they only get that protection for that one season. So, see -- if you did have a spike or issues in the supply chain, they only have that one season of protection for customers. And that's been the problem before.

Unidentified Participant: When you guys comp to the above or below on the ROE band, right -- so, the delivered cost of gas you're going to compare against -- is that what the other half of gas cost for the customer is over that time period? Or, how do you set the reference gas price to see (inaudible)?

Brian Iverson: It's really on, sort of (ph), getting that credit. If the customers are getting a credit, we get an enhanced return. If they're getting an add-on to their bill, it -- you know, in total, it's the reduced return. You're going to sell it, and if you're --

Unidentified Participant: (Inaudible) reference price gas is, I guess, my (inaudible).

Brian Iverson: Well, it's going to depend on what our cost to produce is. So, it's going to be directly tied to the cost to produce. If that's lower than market, you're going to generate that enhanced return. If it's higher than the market today, you're going to take the hit on the 100 basis points.

Unidentified Participant: And the market today would be $5 for you guys? Is that the right market reference price, given your delivered cost of gas, roughly?

Brian Iverson: Delivered cost of gas is probably a little lower than that.

David Emery: Lower than that.

Brian Iverson: Yes.

David Emery: $4s.

Brian Iverson: In the -- yes, in $4s. Any other questions? Okay. With that, I'll turn it over to Mark Lux, our Vice President of Power Delivery, to talk about some load generation projects.

Mark Lux: Well thank you, Brian, and good afternoon and thank you all for joining us today. It's a privilege for me to present Black Hills Corporation's business focus and strategy for two of the three non-regulated business segments, power generation and coal mining.

So, for the next ten minutes or so, you'll be hearing a little bit about the power generation business and our plan for continued profitability. We're going to spend a little bit of time on the new EPA rule, 111(d), and the impacts and opportunities that that creates for Black Hills Corporation. And then we'll conclude with just a brief update on our coal mining business segment.

Starting on slide 44, we describe the power generation business segment. The corporation's power generation business is vertically integrated and an extension of our utility business. We provide profitability as an energy partner of choice, contracting long-term capacity and energy supply to our affiliate electric utilities as an extension to that utility business, as Linn described earlier today.

In Wyoming we own 76½% of the Wygen I power plant, which is a 90-megawatt coal-fired power plant that's contracted to our affiliate utility, Cheyenne Light, Fuel & Power through 2022.

In Colorado we own 100% of the Pueblo Airport Generating Station, a 200-megawatt natural gas combined cycle facility. And that's contracted to our affiliate utility, Black Hills Colorado Electric, through 2031.

We also provide energy service solutions to municipalities. In Wyoming we operate, dispatch and share in market economic energy savings from the City of Gillette's 40-megawatt natural gas-fired simple cycle unit, located at our Gillette, Wyoming energy complex. These operation services are contracted to the City with a long-term economy energy purchase power agreement through 2034.

Very simply, our power generation is an energy solution provider of choice in the utility regions we serve. We provide efficiency by duplicating smaller plant facilities and managing the corporation's generation assets with one core and centralized management team.

We focus and prefer to duplicate our generating fleet designs at our existing brownfield facilities like our Cheyenne Prairie Generating Station, and with our proven record of developing, permitting, and constructing and operating power generation projects, we have demonstrated significant customer savings with successfully executing profitable generation investments.

On slide 45, our strategy is defined and is very clear. We focus on profitable growth within our geographic utility regions of our electric and natural gas utilities. We provide valued customer service while getting better every day, expanding energy partnerships, and we ensure we have a great place to work as the safest energy company in the nation.

Our growth strategy in power generation remains consistent. We sell power plant capacity and energy under long-term tolling arrangements to our affiliate utilities and other utilities in our regions; we provide energy operation services to municipalities under long-term service agreements; and we can provide energy solutions utilizing distributive energy resources within our utility geographic footprint.

On slide 46 and 47, we'll provide you brief~~ly~~ updates on two of the major power projects that have already previously been discussed. Slide 46 is the $65 million investment in a 40-megawatt natural gas-fired peaking unit for Black Hills Colorado Electric, located at our Pueblo Airport Generating Station in Pueblo, Colorado. As previously mentioned, this project was required to replace W.N. Clark as a result of the Clean Air, Clean Jobs statute in the state of Colorado, and our plan to comply with that state law.

This project is 21% complete, on budget and on schedule, for commercial operation in January 2007 (ph). And more importantly, our regulatory team has done a great job in getting cost recovery of this project in the construction cost throughout the construction period, so that we don't have any regulatory lag on the return on investment that we're making in this project.

Slide 47 is a depiction of our $109 million investment in the 60-megawatt Peak View project. This project is being developed again for Black Hills Colorado Electric to comply with the Colorado renewable energy standard, which mandates 30% renewable energy supply by 2020. Currently, Black Hills Colorado Electric is required to meet 20% of that 30%, and this will increase to 30% requirement in 2020, providing future renewable energy project investment opportunities.

The Peak View project, as mentioned, is currently awaiting approval from the Colorado Public Utility Commission, which we anticipate in November this year. And in the meantime, we continue to develop that project, and remain on schedule and on budget, ensuring that we have the safe harbor investment required to preserve the production tax credits which provide value as part of this economic investment. Again, as previously mentioned, this $109 million project is not included in the current forecasts of capital that have been presented previously.

In August of this year, the Clean Power Plan was issued by the EPA. Slide 48 briefly describes this rule. The plan simply requires greenhouse gas emission reductions beginning in 2022 through 2030, and impacts selected power plants across the nation.

For Black Hills Corporation, the units that are impacted are our coal plants at our Gillette, Wyoming energy complex, and two of our combined cycle units, one in Cheyenne, Wyoming, and one in Pueblo, Colorado. Our remaining generation fleet of simple cycle generating units are not impacted by this rule.

The rule simply requires more renewable generation and less coal-fired generation, with increased utilization of combined cycle natural gas-fired generation beginning in '22 and increasing through the year 2030. The plan requires states to file implementation plans for reductions, either through a rate base, which means pounds of CO_2 per megawatt generated, or mass-based, meaning tons of CO_2 emitted, both on an annual basis.

Within the context of the rule, it appears to Black Hills that regional mass-based programs are encouraged. Under either a rate- or mass-based approach, Black Hills can operate and re-dispatch its existing diversified modern generation fleet to comply with the state's emissions reduction required by this new rule.

Slide 49 describes the actions and expected compliance requirements that we'll have to meet in order to comply with the new EPA rule. As mentioned, EPA is clearly leaning towards a mass-based regional approach, and Black Hills is actively engaged in the discussion and formulation of the state's implementation plans for compliance with this rule.

With their new modern fleet of coal plants, compliance impacts will start first by the EPA's defined Building Block 1, which is energy efficiency improvement. Energy efficiency improvements of coal plants will be very minimal for Black Hills Corporation because of our modern, newer fleet of coal-fired power generation.

EPA's second Building Block 2 will require us to increase utilization of natural gas, as Brian previously discussed. So, we will see increased utilization of our combined cycles that we have in Cheyenne, Wyoming, and Pueblo, Colorado, with capacity factors in excess of 75% capacity factors on those units. And we expect infrastructure and equipment investments in our coal-fired power plants to be able to co~~al~~-fire part natural gas with part coal in order to comply with the new EPA rule and the requirements in 2030.

As part of EPA's Building Block 3, we will see increased utilization and expansion of renewable generation projects and new projects -- new renewable projects being developed, to be able to comply with this new rule.

Slide 50 further demonstrates this impact and opportunity in the Midwest, where all four of the electric utility states we serve and have customers in, are in the top ten list requiring the most significant emissions reductions as part of this rule.

Very simply, more reductions will require more energy to be delivered by natural gas and renewable generation, and these impacts will provide investment opportunity for new generation projects across the nation with these types of power projects with renewables and natural gas-fired generation.

We also want to provide you with the update of Wygen I and the impacts that this rule has on the Wygen I purchase option. The Wygen I plant provides profitable earnings with a power purchase agreement containing escalation and government imposition clauses. The purchase option in this contract allows our affiliate utility, Cheyenne Light, Fuel & Power, to purchase 76½% of this unit through the year 2019. The option period for that purchase ends at the end of 2019.

Uncertainty with the Clean Power Plan will, however, delay this decision for Cheyenne Light to exercise its option until the state implementation plans are approved by the EPA, which is anticipated in 2018 or 2019. Wygen I will continue to operate very efficiently and will continue to provide ongoing profitability and long term performance for the power generation segment with its existing power purchase agreement with Cheyenne Light, Fuel & Power.

This concludes the power generation business segment. We'll next move to the coal mining business segment on slide 52.

Our coal mine simply provides low-cost mine mouth coal supply to the five coal-fired power generation plants located at our Gillette, Wyoming energy complex, where we produce 4 million tons of year -- of coal annually. This supply is approximately 700 megawatts of electric power generation to the region and our affiliate utilities.

Slide 53 describes the strategy where we maximize margins from existing coal supply contracts by controlling operating expenses, providing a valued service with quality coal delivered at a low cost, providing great customer value to our partnerships with our coal supply contracts.

Additionally, our strategy is focused on safety and compliance, where this year, for the second year in a row, our coal mine employees received from the state of Wyoming Governor's Office a safety award for being the safest coal mine in Wyoming for a small mine operation. We also received a safety award from the National Safety Council in 2015 for the coal mine safety performance. As seen by the demonstration of the performance of our safety of our employees, our coal mine is a safe and a great place to work.

Slide 54 depicts our strategy for stable cash flows and continued earnings from our mining. The mining business segment continues to provide stable profitability, as demonstrated by our increasing revenues and controlling of our expenses as part of this slide 54.

The next slide shows a mine engineering plan and expected stripping ratios of overburden. Stripping ratio is the amount of dirt in yards to be removed to produce a ton of coal. The average strip ratio expected from 2015 to 2020, of approximately 1.8, is nearly equivalent to our current stripping ratios in 2015. With our mine engineering plan providing consistent, long-term average stripping ratios, we expect the mining business segment to provide consistent profitability and long-term performance.

Our next slide, 56, further depicts graphically our proven results, executing this low-cost supply strategy. The bar graph on the far left is demonstrated coal price of our coal mining operation at less than $1 per million Btus. The next, lighter gray bars -- the five lighter gray bars -- show regional coal-fired power plants and their delivered coal cost and adjacent coal-fired generation in Wyoming, Colorado and Montana.

The darker black graph, three from the right, is the national average of coal delivered in the United States -- in the nation.

And the two blue graphs on the far right are updates of the natural gas price forecast -- the NYMEX prices. And all of that just demonstrates our ability to execute our strategy as a low-cost fuel provider, providing great customer value as an integrated extension of our utility business. So, this concludes our coal mining business segment, and I thank you for your attention, and now turn it back to Jerome Nichols.

Jerome Nichols: Do we have any questions for anyone, for Mark, on power generation or coal mine?

Unidentified Participant: (Inaudible). So, with the Clean Power Plan, does -- how do you see the power generation business going forward? Do you expect that to be a greater proportion of your business? Is there, you know, build-out of potential CCCTs or renewables? And at the same token, how do you see your coal mining business being impacted from that?

Mark Lux: Yes. Good questions. The impacts of the Clean Power Plan on our generation fleet is a question. We certainly see a shift and a re-dispatch of our resources. We will continue to utilize our existing resources with the infrastructure that we'll have to invest, particularly in our coal plants, to be able to co~~al~~-fire with natural gas. And that certainly will reduce the amount of coal production in the later years of that plan, which is out there in that 2030 timeframe.

From now until 2022, we see no impacts, basically, with this plan. Because the reductions do not require anything to happen until 2022. We will see some opportunities for renewable generation projects and more renewable generation. And I think our modern fleet, that's diversified with coal and with combined cycle and with renewables, will certainly provide for best customer value, in terms of the cost impacts to comply with this rule.

So, with that, I think the thing you can take away is, we have, number one, no stranded assets; and, number two, we're going to provide the best economics for our customers with our blended modern fleet.

Unidentified Participant: If you look at the magnitude of reductions you have to have, you know, from a CO2 perspective, the reductions in CO2 basically means you have to go from a coal fleet to a gas fleet, is equivalent to what it is. Does that mean that the coal generation from here goes to fully gas-fueled at some point in time by 2030? Or, how else do you guys, you know, bend that gap to get, you know, a 45% reduction in CO2 emissions?

Mark Lux: Yes. The question is, does it require no coal generation, or less coal generation, than we have today? Certainly the rule does not require you to totally eliminate coal-fired generation. This is a 30% reduction nationally across the nation. And what we are exploring currently is blending a certain amount of coal-fired generation with natural gas. So, we do still foresee some amount of coal generation within our fleet. And the EPA rule actually provides opportunities for that. So, it doesn't eliminate coal totally; but it certainly requires more natural gas, combined cycle, and more renewables to be able to meet that requirement.

Unidentified Participant: Dave, I guess, bigger-picture, you guys spend a lot of time, you know, managing customer bills and being very conscious of that. When you guys look at the CPP and think about, you know, the change in, really, low-cost coal into something presumably more expensive in renewables and some other things, what sort of bill inflation effects do you think you're going to have for your customers as you comply with these EPA standards?

David Emery: Yes. From an outright percentage increase, Dan (ph), we don't know. You know, until we see the state implementation plans, it's a little tough to predict. We know approximately what it would be if Mark had to comply unit by unit. But this rule's not written unit by unit. It's written state by state. So, some of the actions that some of the other utilities might take in those states, may allow us to do less or more to comply with our units. So, the cost question's a real tough one.

You know, we think, though, given the low cost of our coal, even if we have to add gas, we have to add wind, we still have a relative advantage over some of our neighbors and peers. So, while everyone's bill might go up a whole bunch, our fleet's newer; it's more modern. They'll probably go up a little less than some of our nearby utilities.

So, you know, hopefully that'll be a positive from a political standpoint. You know. The rate pressure is going to be real. There's no doubt about it. But until we see these implementation plans it's going to be really difficult to calculate, you know, what we really think the impact's going to be on our customers.

One thing -- when we did the last round of generation at the Wyodak site -- the Wygen III unit; the Wygen II unit -- when we did that resource planning, we ran scenarios that included significant CO2 costs -- you know, like $10 and $20-a-ton-type CO2 scenarios. They were run assuming a CO2 tax, because we really had no idea what the actual plan might look like.

But it basically showed that those units could stand a substantial burden for CO2 costs, and they were still the best choice of resource at the time. So, we don't think we're going to find ourself in a position where the Commissions are second-guessing the decisions we made five and ten years ago to build coal. I mean, we still feel like we did a pretty good job of assessing that risk on the front end.

Unidentified Participant: Mark, you mentioned wind and solar. Maybe you could talk a little bit more about the potential for including solar. Was that kind of a placeholder, or is there anything in the hopper? You know, will the -- do you need the costs to come down a lot more? If you could just talk a little bit more about the solar side.

Mark Lux: Yes. Good question. The question regarding solar, and the cost of solar, and opportunities with solar. We competitively bid through our power generation business ~~and~~in various RFPs.

And most recently, we have started bidding both wind and solar, because the price of solar with the production tax credits that are provided today are becoming much more economical. We see higher capacity factors with wind, upwards of 40%-plus in the states that we have, compared to solar projects which have capacity factors of around 20% to 25% capacity factor. So, until solar panels come down in price a little bit more, we still see wind having a slight competitive advantage over solar at this point. But it's right on the heels, to your point.

So, we're keeping an eye on that, and certainly continue to explore those opportunities with solar as well as wind, in terms of meeting the renewable requirements.

Jerome Nichols: Any other questions for Mark? Very good.

So, at this point, we're going to take a quick ten-minute break. For those on the webcast, we're going to mute that line, and then we'll come back in about eight minutes. So, right now we have 22 minutes after the hour. So, at about 30 minutes after the hour we'll reconvene and get started again. Our next segment will be oil and gas, and we'll start with John Benton in about 10 minutes.

[break]

Jerome Nichols: Welcome back. Next up is John Benton, who is our Vice President and General Manager of Oil & Gas, and he'll give an update on our oil and gas business and strategy transition. John?

John Benton: Thank you. Thank you, Jerome, and thank you for all coming your afternoon, and devoting your afternoon and time to hear all of our stories.

Since last year, there's a lot that's changed in the upstream oil and gas business, since we were -- spoke to you about a year ago. Both oil and gas prices started their fall last fall, and started to decline. We adjusted to that last fall by reducing some of our oil exploration efforts. We went back -- of course, the usual thing: worked with our suppliers and our contractors to reduce our costs overall, so we can continue some of our programs.

By the second quarter of 2015, it was clear that excess oil and gas production supply had transformed the energy market. Our exploration appraisal programs had showed some promise, but the economics did not support our 2016 and '17 capital program, so we made some changes. We reduced our planned capital spending, as Dave mentioned earlier, to amounts that were just necessary -- needed to maintain our leases and our existing production.

We had some great Piceance well results to date -- allowed us to defer the last four completions we had in the plan for the program for this year. Also, we ended up with some impairments as a result of the low prices -- had to make a difficult decision, and reduced our staffing levels by about 25%, and started looking at potential monetization of some of our non-core unprofitable assets.

When you look at this price chart, it's been 30 years since we've experienced this much of a sustained drop in the price of oil and natural gas. I mean, there's probably a lot of folks in this room that weren't in this business 30 years ago. So, last time this happened, 60% of the individuals employed in the industry left the industry.

And the sustained low-price environment did bring about some efficiencies that helped returned the industry to profitability as it moved forward. That's going to happen again with our current environment. It's going to cause us to become more operationally efficient. But in addition to that, it creates an opportunity, including looking at long-term gas price stability and through the implementation of a cost of service gas program.

Quick summary of our program -- our 2014 and '15 program clearly demonstrated our oil and gas division's ability to efficiently execute our drilling and completion program. Once we removed the regulatory roadblocks, we were able to drill and case 13 wells in the Piceance.

By next week, we will finish completing a total of nine of those wells, and have already tested six of those nine. We could easily have completed the remaining four wells by the end of this year. We do not have to complete those wells. The performance of the first nine is expected to more than meet our plant capacity through 2016, and that will give us time to assess this asset for cost of service gas program and to support the utility business with obtaining approval for cost of service gas in the five states in which we will apply -- or the -- yes. Six states, sorry.

There's a table with a lot of data on here, that pretty much summarizes our program to date. I would want to make sure and call a note that the reserve estimates for the 9-41 wells at the top of the table are estimates. We still have a year-end third-party review to go through that, and it may result in some changes to those estimates.

I want to try to do this on the map very quickly. If you look up here, the six wells you see up here are the 9-11 wells. The 9-11 wells are the wells we just brought on in August and September.

We are in the process of completing three more wells on this pad, our Whittaker Flats, which is of course the area where we think there's some additional liquids, and has been demonstrated by the existing producers. And these wells, the 7-23 pad wells, are the last four that have been drilled and cased, and which we'll defer our completions.

Engineers always like pictures and diagrams, so we just threw this in there so could see a bit of a 3D image of what this looks like for us, and what our 9-11 pad looks like for wells. A lot of data out here. I don't know if you have any questions about it. I'll pause for a second, if you've got any questions, and then we'll move on.

One thing to note on this is -- before we move on, is the top of the Mancos pay area (ph) is about 900 feet, here. So, there's a lot of room between where our current well pads lay and where we could potentially lay in another row of wells. So, there's additional development from -- available from this pad as we move forward.

This graphic is a -- what's showing about (ph) our well costs, and what's happened since 2011 through 2015 -- as you can see consistently, we've seen reduction in well costs over that period of time. Some of those improvements have been through the reduced costs that we were able to secure through our service and supply companies -- the contractors that we use; and some of that's also been through program optimization. And we do believe that, when we move forward with this as a part of our cost of service gas program, that we will also see some additional improvements.

This chart just shows our cost per foot for cased and cemented wells. So, we the cased and cemented because sometimes you don't run casing all the way out to the end of the lateral. So, we look at that as our guidepost as it -- what we can do on a drilled and cased cost per foot? So, if you look at the 2013, '14 wells, those ran between $400 and $600 per cased foot. For the last half of 2015, as you move out and look at the wells on the far right of that chart, all those were equal to or less than $400 per foot.

This chart is a little bit slippery (ph). There's less wells on here. Essentially it's our finding and development cost chart. The others that are -- that were on the previous chart, aren't there yet, because we haven't booked reserves for the wells off the 9-11 pad, or the 7-23 pad, or the Whittaker Flats. And again, we'll have year-end bookings for the three 9-11 wells; the three Whittaker Flats wells. 7-23 wells, we won't show, because we won't complete those wells. We can defer those completions.

Now, if you look at this, you could say, well, don't see much improvement in the finding and development costs between what you did in 2013 and the end of 2014. Those are more or less about the same -- somewhere in that $1.50 per Mcf range.

Something to think about that. Those three wells in green -- those were 1,500 foot higher in elevation compared to the Whittaker Flats wells. So, we had to drill 1,500 extra feet in each of those wells, before we could go horizontal. In addition to that, those wells were dry gas wells, so we don't have the benefit of liquids content there also.

And finally, that was in an area where we drilled a well in 2011. It's prone to severe lost circulation drilling hazard, which -- that can add a significant amount to the cost. All three of those wells, we drilled without having a lost circulation problem. So, that's a big improvement in our execution capability in that area.

This is a production plot of our most recent wells, the 9-11 and the 9-41 wells. The early data on the 9-11 wells certainly look a little bit better than the 9-41 wells. All three of those wells, since we brought those on late August/early September -- their average rates have been somewhere between 6½ and 8½ million cubic feet a day; surface flowing pressures of more than 2,000 psi.

So, we've been pretty happy with those results. It fits our type curve. It's pretty difficult to see, but those plots are up there -- that -- up in the upper left-hand corner of the 9-11 and 9-41 wells -- the early data again indicate that they are doing quite well. The actual completed lateral lengths of these wells are somewhat under 9,000 feet. And, you know, we've plotted those in between a 5,000 and a 10,000-foot lateral. So, we're still confident that we're going to meet our expectations for this program.

In summary, our results to date in the Piceance continue to support the resource potential of between 2 and 4 Tcf. Our current project -- projected demand for our cost of service gas program -- I think Brian alluded to this in his presentation -- somewhere between 37 and 38 Bcf a year.

What that means is, a 20-year program for cost of service gas only requires about ¾ of a Tcf. That leaves us with a lot of additional resource potential to support expansion of the program; some non-regulated development potential to bring in other utility companies into the program; or, some partial monetization of the asset.

So, a lot of available opportunity there. We believe that it has great potential for the cost of service gas program and we think the results to date support that belief. While the drop in product prices has not favored the profitability of our current projects, we have made significant changes to the program to adapt to that changing market.

I'd like to thank you for your time, and if there are any questions -- yes, sir.

Unidentified Participant: What kind of gas price would you need to see to reinitiate the CapEx in the (ph) drilling program outside of that -- the cost of service gas program?

John Benton: For non-regulated? I'm sorry, (inaudible), I didn't thank you. So, the question was -- is, what gas price do we need to reinitiate our non-regulated gas program?

A bit of a moving target. As you continue to see improvement in the cost structure, you could say arguably somewhere between that $3.50 and $4.50 price would get you somewhere in there, to where you could reinitiate the program.

Unidentified Participant: Is that a wellhead price?

John Benton: Yes, sir. The question was, is that a wellhead price? And the answer is yes.

Unidentified Participant: Sorry. I meant to ask this when the -- in the utilities section, but if you added SourceGas to the cost of gas program, how much additional demand would that be?

John Benton: I'm going to defer that to -- I think to Brian or Dave. I can guess at that number, but Brian knows it much better than I do.

Brian Iverson: Yes. I mean, it's going to vary, but it's about two-thirds of what ours is, when you look at it. So, the actual throughput. And not the throughput; the actual gas sold. There's transport on top of that, so --

Unidentified Participant: Is there a potential to expand the cost of service gas program beyond what you currently have outdoors, to try to take more advantage of the available gas in the Piceance?

John Benton: So, the -- I'm -- make sure that I understand, the question is, could we expand the cost of gas program using the Piceance asset or other assets besides that?

Unidentified Participant: I guess if -- I was just thinking about, in terms of -- you're saying it's only --

John Benton: Three-quarters of a Tcf.

Unidentified Participant: Three-quarters of a (ph) Tcf. Potentially, other gas utilities that may, you know, be open to doing a cost of service gas with your assets, if it -- if the Piceance were to be included.

John Benton: I think that -- yes, I do believe that there's -- that's one of the opportunities that we've mentioned for expansion, is working with other utilities to bring them in with us as partners in the program.

Unidentified Participant: How much money do you guys have invested in the E&P business in its entirety, between this and legacy, you know, net of what you sold historically?

David Emery: We've got a current book -- we're roughly --

~~Mark Lux~~Rich Kinzley: Yes. If you go back to page 59, that shows you what the current book is. That doesn't exactly tell you how much we have invested, but --

Unidentified Participant: Is that net of impairments or (inaudible) --

~~Mark Lux~~Rich Kinzley: That is net of impairments, net of depletion.

John Benton: It's a good question. I do not have the answer for you.

Unidentified Participant: And then, I guess, you know, with the ongoing business that's -- you're not having a good profit year this year, shall we say, you -- what are the options as far as strategic alternatives to it, so you're not losing money on the (inaudible)?

Rich Kinzley: When I give the financial update in a few minutes, I'll give a little color on that. Yes.

Unidentified Participant: Okay. Thank you very much.

John Benton: How about I introduce Rich Kinzley now, to give the financial update.

Rich Kinzley: Thanks, John. So, I'm on slide 72. Pardon me -- 71. The team's done a good job kind of walking through our different strategies, and these bullet points reiterate, you know, from a financial perspective, a lot of the things that the team was talking about. But, as we acquire customers; invest money prudently in our utilities; you know, put capital in as -- to replace O&M expenses; continuous improvement efforts -- all those things strengthen us financially, help improve our earnings, and serve our customers efficiently.

On the capital structure side, we're committed to maintaining our solid credit ratings, and through the SourceGas acquisition we intend to maintain those as we finance that.

Now, of course, our track record of dividends -- we've got a slide coming up here. 45 years in a row of increases. Second-longest streak in the utility industry, and we intend to continue that as well.

Earnings guidance. We released yesterday an update to our 2015 earnings guidance. We upped each end $0.10. So, we're $2.90 to $3.10 per share now. Assumption-wise, we kept our capital forecast for this year the same as what we'd disclosed previously. And of course, this assumes normal weather and no outages at our facilities and so forth -- normal operations.

In the middle of this slide, you'll see the full year oil and gas assumptions. We've updated those. Our production range, we narrowed. We were 12½ to 14 Bcf; now we're at 12.9 to 13.3 Bcf production for the year. And then our pricing in the second sub-bullet -- all those numbers are down, of course.

Our last issued guidance on pricing was back in February, and of course prices have continued to remain weak, so we've updated for the full year what we -- what our average pricing looks like. And then the depletion expense -- our previous guidance on that was $2.35 to $2.55.

And if you look back on slide 59, you'll see the impairments that we took in the first and second quarter. And while we can't anticipate exactly what they might be in the third or fourth quarter, it's likely we're going to have more, because the average price -- you use a rolling 12-month average price to calculate those impairments and apply those to your reserves going forward. Those averages keep coming down. We know what the third quarter average is now, and the fourth quarter prices were higher last year, so they'll roll down further in the fourth quarter.

All that said, as we take those impairments it reduces our future depletion rate. So, our average depletion for the year, we've guided down to the range you see there of $1.90 to $2.10. Now, if we were -- if we have to take impairments in the third and fourth quarter -- which, again, based on prices, looks likely -- you'll see lower depletion going forward as well.

The guidance assumptions assume no equity financing this year and no acquisitions or divestitures for the remainder of the year; and then also, the -- it excludes the impairments we've taken, and any acquisition costs incurred during the year. We single those out as special items.

Dave mentioned earlier, we're looking at our Colorado IPP asset. And Mark described that asset when he was talking about our power gen assets. This is our 200-megawatt power plant in Colorado that is owned by our independent power division -- our power generation division. And it's contracted through the end of 2032 with Colorado Electric, our utility. We've had inquiries over the last couple of years on this asset, and given where we see the market on these kinds of assets, a premium valuation may be available to us.

And so, we are kicking a process off to see what kind of value we can generate out of that. If -- one other key point there, too, is, of course, we use bonus depreciation with that asset. And so, there is not much tax basis here. But because of our NOL position, there wouldn't be any immediate tax leakage if we in fact sell a portion of it. And then, if we do sell a portion of it, we would only probably sell up to 49.9% -- a minority interest. Because we want to maintain control of that asset, since it's contracted to our utility, and continue to operate it.

Financing update on the SourceGas. We completed our bridge facility. Of course, we had that in place when we announced the deal, as a backstop for the financing. We got that syndicated shortly after announcing the deal. We will assume $700 million to $720 million of SourceGas debt at close. And then the difference is -- the $1.17 billion on the $1.89 assumed price, is broken up between debt and equity.

Now, with the potential sale of Colorado IPP and on the oil and gas side, you know, certainly it's not going to generate the kind of dollars Colorado IPP would; but we're looking at selling non-core assets here as well. Between those asset sales, we will be able to reduce the financing needs for SourceGas.

So, we issued a revised range of equity that we'll need to the deal closed. Revised it to $450 million to $600 million from the previously-disclosed $575 million to $675 million. And then also, a little color around our plan to use the unit mandatory convertibles in the range of $200 to $300 million.

Other financing. We're also evaluating probably putting an at-the-market, or an ATM, program in, to dribble equity out in the future. That, we wouldn't be able to put in place probably until 2016, but we're looking at that.

We did hedge $250 million of ten-year treasury interest rate risk through April in '17. So, we can use that swap against debt that we place for the SourceGas financing or other financing needs that we see forthcoming. And we did that last Friday, when -- after the jobs report came out, and rates dropped a bit. So, we're pretty happy with what we executed there. And we'll continue to look for opportunities to do that as we move forward.

And then, of course, Peak View's coming. If approved by the Colorado PUC, we'll have to evaluate our options to finance that. But, as an example, if we do put an ATM in place, that could help with that.

I've got three slides on capital investment. Here's the first. You can see our strong historical capital program, which has helped us grow the business. A lot of that's been generation over the last five, six years. But you see, we still have a strong capital program in '16 and '17 in our utilities, and our capital in '16 and '17 is very focused on our utilities. Linn put that chart up earlier.

This is just more breakout. The top half of the -- you saw already in Linn's slides. But it's the utility capital. You can see the power gen. And then the rider eligible at the bottom. Linn talked a little bit about that. We do exclude from the rider eligible capital at the bottom the cost of service gas at this point, until we get regulatory approval. But effectively, that will be rider eligible, and we will include it at the bottom upon approval. These also -- the projected capital here also excludes Peak View and excludes any SourceGas additions.

When we look at CapEx -- and really, the point on this slide -- it's slide 77. At the bottom, you see, particularly in the bottom left, how our capital outstrips our depreciation for a nice rate base growth.

Financial metrics on slide 78. You see the improvement over the last five, six years. We're proud of that track record. Our earnings metrics and return metrics and cash flow metrics have all improved as we've moved through the last few years, and the addition of SourceGas will do nothing but strengthen our cash flows and profile moving forward.

Slide 79 is our dividend history. Did increase this year, a little higher than we've been doing the past few years. But, 45 years in a row. We're proud of that.

Capital structure. We have a strong balance sheet. We did take a little hit on the equity side because of the impairments we took in the first and second quarter this year, which -- non-cash, but they do reduce our equity. So, moves the debt to total cap up a bit, but still sitting in a good position there. Strong capitalization.

Credit ratings. When we announced the SourceGas deal, all three agencies affirmed their ratings on us. Moody's and Fitch gave us a negative outlook until they can see more clarity around the financing. But it was a good sign that they affirmed our ratings upon the announcement of the deal.

And lastly, on slide 82, here's a look at our historical earnings per share and operating income. Good, strong growth. You're all familiar with that. We like the fact that we were able to move this year's up to $3 as the midpoint of the guidance range. So, we continue to show that growth. And then on the far right you see the trailing 12 months.

As of June, our utilities really had nice growth, the trailing 12 months this year, compared to the trailing 12 months last year. The black-shaded area, the non-reg, went down a bit, and that's really commodity price-driven, and the fact that E&P hasn't fared as well in this commodity price environment.

With that, I'll open it to questions. Mike.

Unidentified Participant: Thanks, Rich. Just not clear -- what is the drivers that's driving up the $0.10 increase on the low end and the high end of the range?

Rich Kinzley: Yes. We didn't really disclose anything particularly there, and you'll get some more color when we release our third-quarter earnings at the beginning of November. But if you look at our year-to-date results through June, you know, the business units are all performing very well, Mike. Yes.

Unidentified Participant: Just sort of a -- I apologize for a mathematical question here, but if -- the SEC PV10 test benefit that you guys see for depletion -- what would -- what does that add specifically to your earnings? What is the EPS benefit from that? That's the first question.

Rich Kinzley: Sure. Well, if you go back to slide 59, I mean, I can't really give you a number. But what I can do is kind of guide you in the right direction, I think. If you -- you know, we previously disclosed a depletion range for this year of $2.35 to $2.55. Now we're in the $1.90 to $2.10 range. And that's really -- the decrease is driven off the impairments we took in the first and second quarter, primarily. So, the second half of the year's depletion is going to be lower than the first half was. Okay?

Unidentified Participant: Okay. So, it's very substantial.

Rich Kinzley: And then, you know, if you look at the trailing 12-month prices that we have on that chart for the third and fourth quarters -- which, the fourth quarter's, of course, using kind of strips -- you can kind of linearly maybe guess at where impairments are going to h~~it~~ead and what might happen to depletion moving forward.

Unidentified Participant: Okay. And then the second question I have is, with respect to the equity financing, with sort of a volatile market and what have you -- any thoughts about how to perhaps hedge that, or forward sales? We've seen, for instance, you know, in some transactions, people being very aggressive, and what have you. And I'm just wondering if you guys are thinking about there -- how we should think about the timing of equity issuance and what have you?

Rich Kinzley: Right. Well, we're looking at all our options there. Forward -- I mentioned the ATM. Certainly a straight equity issuance in the convert. From a timing perspective, you know, we're probably not going to be able to do anything before we get our third quarter earnings out. But we're going to continue to monitor the markets. We're going to look at all those options. Our intent is not to draw on the bridge, and get this financed ahead of close. So, that gives you an idea of when we'll be looking to move, but --

Unidentified Participant: So, I mean -- but won't this -- on top of that, though -- so, in other words, are you planning on waiting till basically close to close, or what have you, in terms of issuing is there any thought about perhaps hedging that -- the equity price risk, I guess, is what I'm sort of asking. Prior to that.

Rich Kinzley: As I said, we're looking at all those options. We're talking to our banks. And, you know, nothing imminent; but certainly, we're not going to wait too long either.

Unidentified Participant: You guys mentioned that you're looking at selling the 50% stake in one of your IPP assets. We've seen a couple of asset sales announced in the past couple of days. Is that more a function of just needing the cash right now for the transaction; or is it just, you're seeing more interested international buyers or yield-oriented investors there?

Rich Kinzley: Sure. Well, a little bit of all of the above. But really, we're certainly not selling it just because we need the cash for SourceGas. We're looking at, strategically, if we can get the kind of value that we think is in the market right now for that asset, it probably makes sense to sell it. We would probably be looking at this in any event. We've been approached by parties, and the timing may be real good.

Unidentified Participant: Good. And then I have another question for John. The guidance slide has, I think, an $0.89 wellhead gas price on there, that's assumed in your guidance right now. Could you talk a little bit about just the regional gas pricing in the Rockies, and how that compares to kind of a cash cost for the marginal price (ph) over the long term, or an all-in price over the long term?

John Benton: So, in -- I'm sorry, if you could help me out with some -- I'm not a finance guy.

Rich Kinzley: I may be able to answer this. John can probably give you better color on the particular basin pricing out there. But one of the things that is netted out of there is our gathering and processing cost. So, that drives it down quite a bit.

~~Unidentified Participant~~John Benton: Yes. And it also -- the $0.89 is a dry gas, so it doesn't reflect the value we get from the liquids as well. So, I'm not sure if that answers your question or not.

Unidentified Participant: I mean, is that abnormally low versus a long-term price, even if you adjust for the processing costs, versus peers in the region?

~~Unidentified Participant~~John Benton: No. I mean, that's -- our processing costs are a bit higher because we're running through a new plant, compared to, say, Williams or someone else. But notionally that's about what Piceance Basin is experiencing today for wellhead price. And that's after -- as Rich said, it's after taking our costs out.

Rich Kinzley: Nick?

Unidentified Participant: Sorry if I missed this, but the reduced equity need for SourceGas -- did that assume the Colorado IPP plant sale?

Rich Kinzley: Certainly the bottom end of that range would. The top end -- if we were able to bring the top end of the range down, too, you know, as we continue to hone in our forecast and look at CapEx in ’16 and beyond, you know, we knock the E&P CapEx down. So, that knocked the top end down a bit, even if we don’t sell Colorado IPP.

Unidentified Participant: Thanks. And then can you talk about how you plan to finance your CapEx, kind of, aside from SourceGas and any external capital needs there?

Rich Kinzley: After the deal? Yes. I think the cash -- you know, the cash flows that our business has generated are obviously very good, and adding SourceGas is going to do nothing but improve that. So, we’ll manage. We don’t anticipate needing additional equity, I guess, other than if we put an ATM in, in the short-term.

Maybe one other little bit of color on that: we probably will lever up a little more than you would normally see us at closing. So, we’re going to have to work over the next couple of years to get that de~~al-~~ levered through an ATM program, through strong CapEx management, and then the cash flows that the businesses are going to provide us.

Unidentified Participant: Thanks. And just a followup to that -- how should we think about the ATM program? Is that, you know, one of the tool that you use to finance the SourceGas acquisition, or is it kind of unrelated?

Rich Kinzley: That would really be to help finance any near-term CapEx post-acquisition, more than likely.

Unidentified Participant: Peak View.

Unidentified Participant: Like, basically (inaudible) -- like, Peak View or cost of service gas.

Rich Kinzley: Right.

Unidentified Participant: That’s what we’d use it for.

Rich Kinzley: Yes.

Unidentified Participant: Would it be possible for the utility to buy the IPP? Does that make sense?

Unidentified Participant: Brian, can you --

Brian Iverson: Yes. I think it’s certainly a possibility. You know, you’d have to do that analysis based upon what the bids come in, and how that would look, you know, on a rate-based model for customers, as far as customer cost.

Unidentified Participant: Hey. John from SNL Financial. Question for you on the balance between CapEx and the dividend increases. You guys said that you kind of plan -- or, you’re the second-highest consecutive increases in dividends consecutively. Is that plan to continue, and how do you balance that versus continue to reinvest back into the firm?

David Emery: Yes. We don't specifically state that -- what we're going to do for long-term dividends. I mean, we don't specifically state whether we're going to increase it or not, although we do state pretty heavily that we're awful proud of that track record. So, you know, you can infer into that what you will.

We do definitely balance capital investment opportunities versus that dividend increase. And if you look at the numbers in there, you know, we went back to $0.02 for a few years, and then we went up to $0.04, and then we went to $0.06. It's really a function of what we see the forward-looking capital investment opportunities to be, versus cash flows.

So, we had a period there when obviously we were in the recession. We knew we had a ton of generation to build. Backed it down to $0.02. Things started loosening up and we've got a lot stronger on the cash flow side. Credit metrics got better and better, so we raised it a little bit. We do have a tradeoff there. But, you know, both are important to us.

And obviously we want to maintain our capital investment. You know, our growth rate that Rich showed you, meant more that essentially double the industry average, is something we're also very proud of, and that's a key focus. But we're really proud of that 45-year track record.

Rich Kinzley: Any last questions? Dave, do you want to say anything in closing? Jerome?

David Emery: Jerome might have another question to do.

Jerome Nichols: Last chance. Any final questions? Right. That concludes our presentation for today. I'm going to turn it over to Dave for final remarks.

David Emery: Well, thanks again, everybody, for being here today. As you can see, we're excited about what the future holds for the company.

The SourceGas acquisition is going to be a large addition for us -- you know, 55% increase in the size of our utility customer base and, you know, one that provides a lot of forward investment opportunity, much of which is rider eligible capital. And that's one of the things that we found really attractive about the SourceGas opportunity. Plus, the obvious operational advantages of being in three of those states already. So, the combination there is exciting.

The part that makes us most excited about it is, we know we can execute on it. We've done it over and over, as Linn talked about. It's something we're very comfortable is in our skill set. All the acquisitions Linn talked about from 2004 on -- the core team of people that are doing all that work are the same people. So, they're very well-practiced at what they do, and they're really good at it. So, we're excited about that.

The base growth in our other businesses, from some of the other opportunities -- we talked about cost of service gas, is an excellent example. Some of load growth in areas like Cheyenne; just the base growth in areas like northern Arkansas -- all of those give us a good, stable, solid utility growth, absent some of these other things.

So -- and again, it's back to things we know well. You know. It's generation construction; transmission construction. You know, Mark and his crew have built 19 plants. That's a lot. And they're all done on time and on budget, which is phenomenal. So, it's a key skill set.

So, we're really excited that all of these opportunities are still available, that we've had and developed over the last ten years. Add on top of that SourceGas and cost of service gas and some other things. Future's exciting. We're really looking forward to executing on that opportunity.

So, thanks for your time today. We appreciate the attendance of everyone on the webcast and here in person. Hopefully you can join us here after we break up.

Before we do, I want to say a quick thanks to Jerome and Leslie Hartwell, who's been running the microphone around, out of Kimberly's group. These things take a lot of time and effort and work to put together, so let's give them a little round of applause, you think (ph)? All right. Thank you, everyone.

CONSTELLATION NEWENERGY-GAS DIVISION, LLC

EXHIBIT SB-3

OF

STEPHEN BENNETT DIRECT TESTIMONY

IN THE MATTER OF THE APPLICATION OF BLACK HILLS NEBRASKA GAS UTILITY COMPANY, LLC D/B/A BLACK HILLS ENERGY FOR APPROVAL OF ITS GAS HEDGE AGREEMENT WITH BLACK HILLS UTILITY HOLDINGS, INC.

APPLICATION NO. NG-0086

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February 26, 2015

VIA ELECTRONIC FILING

Public Utility Commission of Oregon
3930 Fairview Industrial Drive SE
Post Office Box 1088
Salem, Oregon 97308-1088

Attn: Filing Center

Re: **UM___ Application for Prudence Review of Costs of Post-Carry Wells**

Northwest Natural Gas Company, dba NW Natural ("NW Natural" or "Company"), files herewith an original and five copies of its Application for Prudence Review of Costs of Post-Carry Wells and testimony of Barbara Summers and C. Alex Miller.

Please call me if you have any questions.

Sincerely,

/s/ Mark R. Thompson

Mark R. Thompson
Manager, Rates and Regulation

enclosures

BEFORE THE PUBLIC UTILITY COMMISSION OF OREGON

UM _____

In the Matter of PUBLIC UTILITY COMMISSION OF OREGON, Application for Prudence Review of Costs of Post-Carry Wells	**NORTHWEST NATURAL GAS COMPANY'S APPLICATION FOR PRUDENCE REVIEW OF COSTS OF POST-CARRY WELLS**

I. INTRODUCTION

This Application concerns NW Natural's investments in gas wells made in 2014 under the Company's joint venture agreement, originally entered into with Encana Oil and Gas (USA), Inc. (Encana) and later transferred to Jonah Energy, LLC. As discussed below, and in the supporting testimony of C. Alex Miller and Barbara Summers, NW Natural's decision to invest in these wells was reasonable, and NW Natural therefore requests that the Commission issue an order finding that (1) the investment was prudent; and (2) the costs of the investment should be included in customer rates through the 2015 PGA, and subsequent PGAs as additional costs are incurred.

II. BACKGROUND

A. Original Agreement

In 2011, NW Natural negotiated an agreement to enter into a joint venture with Encana to develop natural gas wells in Wyoming's Jonah Field. Under the original transaction (Original Agreement) NW Natural expected to invest approximately $251 million over five years and to receive approximately 93 billion cubic feet (BCF) of gas over a 30 year term. The majority of the gas was expected to be received in the first ten years. The purpose of the transaction was to provide NW Natural's customers with a reasonably-priced, long-term, stable source of gas —in other terms, a long-term hedge. In analyzing the transaction, NW Natural relied on well volume forecasts prepared by oil and gas consultants, Netherland Sewell & Associates, Inc., (NSAI).

Under the Original Agreement, NW Natural and Encana were obligated to jointly fund 102 "carry wells" in three separate sections of Jonah Field. The wells were referred to as "carry wells" because NW Natural had agreed to "carry" a portion of Encana's pro rata share of the drilling costs in three separate sections of Jonah Field. In exchange, NW Natural would receive a share in the total production of the field in which the well was drilled, and, in some cases, a share in the individual well's production as well. In addition, after the drilling of the carry wells had been completed, NW Natural would have the option to participate in the drilling of additional elective "post-carry" wells. For each post-carry well for which NW Natural helped fund the drilling, NW Natural would receive a percentage of the gas produced from that specific well (as opposed to a percentage from one of the sections). Importantly, for the post-carry wells, NW Natural was required to fund only its own pro rata share of the drilling costs—equivalent to its interest in the relevant section.

In January of 2011 the Company filed for regulatory approval of the Original Agreement. Specifically, the Company requested that the Commission find the transaction prudent, and approve the costs for inclusion in customer rates. The Commission opened an investigative docket, UM 1520, and ultimately adopted a stipulation filed by all parties agreeing that the investment was prudent. Importantly for this Application, the Commission accepted the following provision in the stipulation without comment:

> [T]he Parties agree that a prudence finding by the Commission at this time should apply only to the Company's decision to enter into the Proposed Transaction, and not to any subsequent decisions the Company might make in terms of exercising its discretion to manage the contract. ***The Parties specifically agree that a prudence finding by the Commission at this time should not, for example, extend to a future decision by the Company to participate in drilling Elective [post-carry] Wells, as that term is defined in the Carry and Earning Agreement (NWN/501). If the Company does choose to participate in drilling Elective Wells, the Parties agree that such decisions would be subject to separate determinations of prudence in future proceedings.***[1]

B. <u>Second Amended Agreement</u>

After 72 of the 102 carry wells had been drilled under the Original Agreement, Encana notified NW Natural that it intended to sell its interests in Jonah Field. At that same time, Encana requested that NW Natural agree to terminate its obligation to fund and drill the remaining 30 carry wells, in order to remove certain conditions of the Original Agreement that Encana believed might make the asset harder to sell. After weighing its options, NW Natural agreed to release Encana from the obligation to drill additional carry wells in return for certain accommodations—the most important being Encana's agreement to increase NW Natural's ownership share of the drilling that had occurred to date. The parties implemented these changes in the Second Amended Agreement, or Second Amendment.[2] Importantly all other rights and obligations

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[1] Order No. 11-180, Appendix A at 6 (emphasis added).

[2] The parties had previously entered into a first amendment of the agreement when NW Natural transferred its interests in the Original Transaction to an affiliate, in order to ensure entitlement to certain tax credits. The Commission approved the transfer in Order No.13-065.

conferred by the Original Agreement remained in place, including the terms governing the drilling of post-carry wells.

C. NW Natural's Decision to Invest in Post-Carry Wells

In December of 2013, Encana sold its interests in Jonah Field to Jonah Energy LLC ("Jonah Energy"), a newly formed subsidiary of TPG Capital, and in April, Jonah Energy informed NW Natural that it was tentatively planning to propose the drilling of four post-carry wells in the near future. On May 7, Jonah Energy followed up this notice with formal requests to drill two wells and requests for another seven wells following close behind. Under the Second Amended Agreement, NW Natural had 30 days to respond.

NSAI's data suggested that the gas from the post-carry wells would be very favorably priced. However, NW Natural viewed the risks raised by participation in those wells as significantly higher than participation in the carry well. When the Company invested in drilling a carry well, it had received an increased ownership percentage in all producing wells in the section, including those that had been drilled prior to the date of the Original Agreement. Accordingly, any risk that the specific well drilled might underperform was mitigated by the increased interest in the other producing wells. On the other hand, when the Company invested in a post-carry well, it received an interest only in that particular well. Thus, because of the riskier nature of the investment, NW Natural approached the parties and suggested that NW Natural shareholders invest in the post-carry wells, accepting both the benefits and the risks presented. Staff and the parties disagreed with that approach. They viewed the opportunity to participate in the post-carry wells as a customer asset, and stated that the Company would need to make a prudent decision ***on behalf of customers*** as to whether or not to invest.

NW Natural accepted the parties' view and developed a framework by which to analyze each of the first nine requests for consent presented by Jonah Energy. Given that the investment in the Original Agreement was intended to act as a long-term hedge, NW Natural consented to any well for which the expected cost of gas compared favorably to the costs of a ten-year financial hedge. The Company calculated the estimated cost of gas for each and based on its analysis, NW Natural agreed to invest in seven of nine of the wells proposed.

In early October of 2014, NW Natural began receiving reports on the early performance of the seven post-carry wells. This preliminary data showed that initial volumes were below forecasts, and suggested that ultimate recovery might fall short as well. NW Natural engaged NSAI to investigate the possible causes of the apparent underperformance, and to update its forecasts for these and the remaining post-carry wells. Based on this analysis, NSAI has revised downward its forecasts, and as a result, NW Natural did not consent to the additional two wells proposed by Jonah Energy in October.

While the economics of the post-carry wells, as updated by NSAI, are not attractive under current market conditions, they could serve as a beneficial hedge if gas prices were to rise significantly.

D. Request for Finding of Prudence

In a prudence review, the Commission examines the objective reasonableness of a utility's actions at the time the utility acted, and not with the advantage of hindsight.

"Prudence is determined by the reasonableness of the actions 'based on information that was available (or could reasonably have been available) at the time.''[3]

The Company believes its decision to invest in these seven wells was prudent and requests that the Commission issue an order approving the related costs for inclusion in customer rates through the PGA process in the same fashion that NW Natural has included the costs associated with the carry wells. As with the original carry wells, the costs of the post-carry wells would be tracked and recovered on an annual basis through NW Natural's PGA mechanism. Any variances would be shared between customers and the Company on the same basis as all commodity costs.

III. CONCLUSION

For all of these reasons, NW Natural requests that the Commission find that its investments in the seven post-carry consented to in 2014 are prudent and to approve the ratemaking treatment as described herein.

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[3] *Re Portland General Electric Co.*, Docket UE 196, Order No. 10-051 at 6 (Feb. 11, 2010). See also, *Re PacifiCorp*, Dockets UM 995/UE 121/UC 578, Order No. 02-469 at 76 (July 18, 2002) ("prudence is measured from the point of time of the decision at issue, not with the advantage of hindsight . . . we must take the position of a reasonable person at the time the decisions had to be made").

Respectfully submitted this 26th day of February, 2015.

McDowell Rackner & Gibson PC

/s/ Lisa F. Rackner
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BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UM ____

NW Natural

Direct Testimony of Barbara Summers

February 26, 2015

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Rates & Regulatory Affairs
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I. INTRODUCTION AND SUMMARY

Q. Please state your name and position with Northwest Natural Gas Company ("NW Natural" or the "Company").

A. My name is Barbara Summers. My business address is 220 NW Second Avenue, Portland, Oregon 97209. My current position is Director of Business Development for Northwest Natural Gas Company, d/b/a NW Natural ("NW Natural" or the "Company").

Q. Please summarize your educational background and business experience.

A. Prior to joining NW Natural as Director of Business Development, I held similar positions with PacifiCorp and Scottish Power as Vice President, Business Development and Vice President PacifiCorp Power Marketing, now PPM. In addition to my natural gas and electric utility experience in business development and transactions, I worked for five years in the telecommunications industry where I was responsible for negotiating and evaluating acquisitions and joint ventures as well as potential start-up businesses. I have a BS in Business Administration from Portland State University.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to explain the Company's actions leading to its decision to participate in the development of certain additional gas reserves referred to as "post-carry wells". This will include our decision to enter into an amendment to the original transaction with Encana Oil & Gas (USA) Inc. (hereinafter, "Encana"), terminating the "carry well" drilling program. The original transaction is referred to as the "Original Agreement" and the transaction as

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amended is referred to as the "Second Amended Agreement" or "Second Amendment." I will describe the reasons behind the Second Amendment and the terms of the amendment. Finally I will discuss the preliminary results we are seeing from the post-carry wells we have drilled to date and the implications for future drilling decisions.

Q. Please summarize your testimony.

A. In 2011, NW Natural and Encana entered into the Original Agreement with Encana to develop certain gas reserves in the Jonah Field in Sublette County, Wyoming. The purpose of the transaction was to provide NW Natural's customers with a reasonably priced long-term, stable source of gas – in other terms, a long-term hedge. Based on reserve forecasts provided by Netherland and Sewell & Associates (NSAI), the Company estimated that the transaction would provide it with 93.1 Bcf of gas over thirty years—with the majority received in the first ten years—priced at an average of $0.529 per therm.

The Original Agreement called for NW Natural and Encana to jointly fund the drilling of 102 "carry wells". In return for each well drilled, NW Natural would receive a share of the gas produced in specific sections of the field, and, depending on where the carry well was drilled, a share of the gas produced by a specific well. In addition, after the drilling of the carry wells had been completed, NW Natural would have the option to participate in the drilling of additional elective post-carry wells. For each post-carry well for which NW Natural helped fund the drilling, NW Natural would receive a percentage of the gas produced from that specific well.

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In January of 2014 Encana informed NW Natural of its intention to sell its interests in the Jonah Field, and requested that NW Natural terminate Encana's obligation to drill and NW Natural's obligation to fund the remainder of the carry wells. After negotiations, NW Natural and Encana agreed to terminate the carry well program after 72 of the originally-planned 102 wells had been drilled; in exchange NW Natural would receive increased ownership percentages in the sections designated in the Original Agreement. NW Natural retained the right to participate in the development of any future reserves – the post-carry wells – within NW Natural ownership sections.

Encana subsequently sold its interests in Jonah Field to Jonah Energy LLC ("Jonah Energy"), an affiliate of TPG Capital, and beginning in May of last year, Jonah Energy began proposing that NW Natural consent to participating in the development of eleven post carry wells. NW Natural has consented to participate with Jonah Energy in the drilling of seven post-carry wells, based on its analysis showing that the gas expected from the wells would be well-priced in comparison to other potentially-available long-term hedges.

Early reports of volumes produced by the seven post-carry wells in which NW Natural participated have been substantially below the levels expected, and as a result, NW Natural did not consent to the last two wells proposed. In addition, NW Natural asked NSAI to perform additional analysis to determine whether disappointing initial volumes were indicative of lower-than-expected volumes over the life of the wells, the cause of the underperformance, and to revise its previous analysis, as necessary, in light of the results to date. Based on its new analysis NSAI has revised its forecast volumes downward. Consequently, the Company would not participate in additional post-carry wells unless market conditions change dramatically—or new data shows better results.

II. BACKGROUND ON THE ORIGINAL AGREEMENT

Q. Please describe the general terms of the Original Agreement?

A. The Original Agreement called for NW Natural and Encana to jointly fund the drilling of 102 “carry wells” in exchange for a share of the gas produced in certain sections of the Jonah Field. The wells are referred to as “carry wells” because NW Natural was required to “carry” a portion of Encana’s pro rata share of the drilling costs.

Approximately 54 carry wells were to be drilled in Sections 32, 33, and 34 (the “Updip Area”) while 48 carry wells were to be drilled in Sections 8 through 17, (the “Downdip Area”). For each carry well drilled in the Updip Area, NW Natural would receive a share of the gas produced in Sections 32, 33, or 34; for each carry well drilled in the Downdip Area, the Company would receive a share of gas produced in Sections 32, 33 or 34, plus an interest in the gas produced from the specific Downdip well drilled. Interests assigned to NW Natural with each well would begin in Section 32 until the Company’s interest reached 45%, then move to Section 33 until the Company’s interests reached 45%, and then move to Section 34 where interests would be assigned until the Company’s interest reached 32.5%.

In addition, after all of the carry wells had been drilled, NW Natural would have the option to participate in drilling additional elective post-carry wells. For

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each post-carry well for which NW Natural helped fund the drilling, NW Natural would receive a percentage of the gas produced from that specific well (as opposed to a percentage from one of the sections). Importantly, for the post-carry wells, NW Natural is required to fund only its own pro rata share of the costs—equivalent to its interest in the relevant section.

Q. Did the Commission find that the Original Agreement was prudent?

A. Yes. In consolidated dockets UM 1520 and UG 204, NW Natural filed the Original Agreement with the Public Utility Commission of Oregon ("Commission"). After an investigation, the Commission approved the parties' Stipulation requesting that the Commission find the Original Agreement prudent, subject to conditions and qualifications, and requesting that the Commission approve certain ratemaking treatment for the costs of the transaction. In its order adopting the Stipulation—Order No. 11-176—the Commission clarified that its prudence finding applied only to NW Natural's decision to enter into the Original Agreement and not to any subsequent decisions NW Natural might make in exercising its discretion to manage the Agreement.

Q. Has the Company amended the Original Agreement, since it was approved?

Yes. In February 2013, the Commission approved NW Natural's request to assign the Original Agreement to NW Natural's wholly-owned subsidiary NWN Gas Resources LLC (NWN Gas Reserves).[1] The assignment was necessary to

[1] *In the Matter of NW Natural Gas Company's Application for Approval of Affiliated Interest Transaction*, UI 329, UP 284, Order No. 13-065 (Feb. 26, 2013).

ensure that the Company realize the tax benefits that were expected when the Company entered into the Original Agreement. Then, in March of last year, NW Natural and Encana executed the Second Amendment.

III. NW NATURAL'S DECISION TO ENTER INTO THE SECOND AMENDMENT

Q. What prompted the Second Amendment?

A. On January 14, 2014, Encana notified NW Natural of its intent to sell its interest in the Jonah Field. Encana also asked that NW Natural consider terminating the Company's obligation to fund, and Encana's obligation to drill, the carry wells that had not yet been drilled.

Q. Why did Encana propose terminating the obligation to fund and drill carry wells?

A. Under Section 4.1 of the Original Agreement, Encana had warranted that until all carry wells had been drilled, its interest in the Jonah Field was free and clear of any encumbrances, liens, or security interests other than those specifically permitted by the terms of the Original Agreement (such as royalties, easements, and similar types of encumbrances). Encana believed that any potential buyer would likely require the ability to place liens on its interest for financing purposes. Therefore, in order to facilitate the sale, Encana wished to terminate the carry well program. Encana did not request that NW Natural terminate its rights to participate in future post-carry wells that the buyer might propose to develop.

Q. What were NW Natural's options at the time?

A. Under the Original Agreement, in the event of a sale by Encana, NW Natural had the option to either: (1) retain its interests, including the carry well drilling

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program, under the terms of the Original Agreement, with the new buyer as partner; (2) sell its interests (including the production of the carry wells that had been drilled) along with Encana's interests; or (3) terminate the obligation to fund and drill carry wells, but retain all other rights under the Original Agreement, including the option to consent to the development of future post-carry wells.

As a practical matter, NW Natural saw that it might be able to negotiate more favorable terms in exchange for terminating the carry well obligation, because Encana was interested in NW Natural taking an action for which it did not have a legal obligation. For that reason, the Company initiated discussions with Encana to determine if it could achieve certain accommodations to benefit customers.

Q. What accommodations did NW Natural seek?

A. The main accommodation was related to the volumes NW Natural was receiving from the carry wells that had been drilled under the Original Agreement. Due to lower well production than had been forecast, and also due to some changes to the drilling schedule, NW Natural was receiving lower volumes than it had expected at the time it entered the Original Agreement. NW Natural believed that Encana's request to terminate the carry well program presented the Company with an opportunity to negotiate with Encana to potentially mitigate the lower volumes. Given Encana's desire to sell, NW Natural now proposed to Encana that it would be willing to terminate its carry well drilling obligations in exchange for an increase in the ownership interest in the Jonah Field, thereby increasing its expected gas reserves to a number closer to that originally forecast.

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Q. Was Encana willing to grant this accommodation?

A. Yes. As a result, the carry well program was terminated after the parties had jointly drilled 72 out of the originally-agreed upon 102 wells.[2]

Q. Please describe the adjustment to NW Natural's ownership interests.

A. As described above, under the Original Agreement, as wells were drilled the ownership interests were to be assigned starting with Section 32 and then continuing with Sections 33 and 34. As of the time the Second Amended Agreement was executed, NW Natural had been assigned a 45 percent interest in Section 32, a 41.4 percent interest in Section 33, and no interest in Section 34. Paragraph 3.3 of the Second Amendment provides that NW Natural's ownership interest be increased to 45 percent in Section 32, 45 percent in Section 33, and 49 percent in Section 34.

Section	Before Amendment	After Amendment
32	45%	45%
33	41.4%	45%
34	0%	49%

Q. How do the increased ownership interests impact the volumes from the 72 carry wells that NW Natural expects to receive?

A. At the time the Original Agreement was executed, the Company expected to receive 93.1 Bcf under the original ownership percentages, assuming that all of the carry wells were drilled. Because only 72 wells were drilled, the Company would have expected to receive 65.7 Bcf, or 72/102 of the original volume. As

[2] Encana also agreed to complete a "tubing" project that at the time the parties believed constituted an economical step to increase volumes.

discussed above, the Company had been receiving less gas than originally forecast. After the ownership interest adjustments, the Company now expects to receive from the carry wells between 65 and 67.1 Bcf, which is nearly the same volume (prorated) that the Company expected to receive from the carry wells under the Original Agreement.

Q. How did you determine which option would be most beneficial for customers?

A. As discussed, NW Natural determined that in the event of a sale by Encana, the Company had three options. It could: (1) hold Encana and a new buyer to the terms and conditions of the Original Agreement and proceed to drill the remaining carry wells (“Original Agreement”); (2) sell its interests along with Encana’s interests (“Sell”); or (3) agree to terminate the obligation to fund and drill carry wells but retain all other rights under the Original Agreement, including the option to consent to the development of future post-carry wells in exchange for adjusted ownership percentages (“Terminate”).

While continuing the carry program maintained NW Natural’s target long-term hedge and its investment opportunity, NW Natural determined that not to be in the best interest of customers given current and forecast natural gas prices. We also saw that the *Sell* option would be disadvantageous. While we did not know the price at which Encana would be selling its interests, we were able to estimate a sales price based on recent market activity. We determined that a sale would require a substantial write-down of customer investment and was therefore unacceptable. Accordingly, our analysis and negotiations focused on

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terminating the agreement and securing an upward adjustment in our ownership interests.

Q. Have you performed any analysis to confirm that the Terminate presented the least cost option at the time the decision was made?

A. Yes. To confirm our decision to terminate the carry well program in exchange for increased ownership percentages, we calculated the net present value ("NPV") of the total cost of gas under each option.

To evaluate these costs, we started by determining the gas reserves volumes that would be expected under each scenario, as well as the costs of those volumes. For the *Sell* option, the cost of reserve gas was offset by the expected revenue from the sale of reserve interests.

Next, because the volumes under the *Terminate* and *Sell* options were less than those expected under the *Original Agreement* option, we determined the volumes of any replacement gas required to bring all alternatives to the equivalent volumes, and priced the replacement gas using a forward curve price. Once we had determined the cost of the reserve gas and the cost of replacement gas, for equivalent volumes under each scenario, we brought that total cost to an NPV number.

The table below shows that the *Terminate* alternative is the lowest cost option, with a total NPV cost of $243 million for 64.7 Bcf. The *Sell* alternative has a total NPV cost of $260 million for 67.4 Bcf; and the *Original Agreement* alternative is the highest cost option at an NPV of $299 million for 64.7 Bcf.

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Investment Alternatives	Projected Remaining Gas Reserves for Cost Estimates (Bcf)			Projected Cost Estimates for the Cost/Price of Gas (NPV)			Replacement Cost	Total Cost (NPV) @ 64.7 Bcf
	Reserve Volumes	Replacement Gas Estimates	Total	Cost of Gas	Sales Cost	**Total**	**Total (NPV)**	
Option I - Original Agreement	64.7	0.0	64.7	$299	$0	**$299**	**$0**	**$299**
Option II - Sell*	32.5	64.7	64.7	$0	$59	**$59**	**$201**	**$260**
Option III - Terminate	55.5	9.2	64.7	$225	$0	**$225**	**$18**	**$243**

**The reserve estimate for the price of gas is used to calculate the costs of selling NW Natural's ownership rights. The Company would still need to purchase 64.7 Bcf in replacement gas to acquire the same amount of gas under the Original Agreement.*

Q. Did you include the value associated with post-carry wells in your analysis of the option to terminate the carry well program?

A. No. When we were making the decision, we did not know if we would consent to participate in the drilling of post-carry wells, or the extent of our participation if we chose to do so. Therefore, while we believed that the post-carry wells *might* provide significant benefits to our customers, we did not consider those benefits in our analysis. That approach was consistent with our analysis supporting the Original Agreement. We assigned no value to post carry wells in the Original Agreement.

Q. Please describe the provision of the Second Amendment terminating the parties' obligations to fund and drill carry wells.

A. Paragraph 4.1 of the Second Amendment provides that the obligations to fund and drill carry wells terminated upon the effective date. Importantly however, paragraph 4.2 states that other than the provisions specific to any ongoing obligation to drill and fund carry wells, all other provisions of the Original Agreement remain in full force and effect.

Q. Do all of the other terms of the Original Agreement remain in force?

A. Yes. Section 4.2 expressly recognizes that the rest of the Original Agreement will continue in full force and effect until all wells have been plugged and abandoned and all necessary reclamation has been completed. Thus, the terms related to producing wells remain the same, including NW Natural's entitlement

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to receive a percentage of the gas produced by all wells in sections 32, 33 and 34—even those that will be drilled in the future. In addition, terms regarding the post-carry wells will remain in force.

Q. Did Encana ultimately sell its interests in the Jonah Field?

A. Yes. On March 28, 2014, Encana signed an agreement to sell its interests in the Jonah Field to Jonah Energy, a subsidiary of TPG Capital, for a purchase price of approximately $1.8 billion.

Q. Please describe NW Natural's right to participate in the post-carry wells.

A. As I discussed above, under the Original Agreement, Encana and NW Natural committed to participate in drilling 102 carry wells. For each carry well drilled, NW Natural received an ownership interest in the gas produced by all of the wells in the current earning section plus an interest in the individual well if the well was drilled in the Down Dip section. After all 102 carry wells had been drilled, NW Natural had the ***option*** to participate in the development of future reserves drilled in Sections 32, 33 and 34. These future reserves were referred to as post-carry wells because each side would bear its respective share of the costs and therefore NW Natural would not be required to "carry" any portion of Encana's/Jonah Energy's drilling costs. For each post-carry well in which NW Natural consented to participate, the Company would receive a share of the gas produced from that well. Under the terms of the Second Amended Agreement, the additional wells that may be drilled in sections 32, 33, and 34, including the 30 former carry wells that were not drilled, will be classified as post-carry wells.

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This means that NW Natural has the option to participate in the drilling of the wells but is not required to do so.

Q. Does the development of post-carry wells present any risks that are different from those associated with the carry wells?

A. Yes. As explained above, the Second Amended Agreement provides many of the same protections as were provided for the carry wells. However, there are two areas of increased risk presented by the post-carry wells: volume risk and the risk of capital cost over-runs. In the Original Agreement, for each carry well drilled NW Natural received an increased percentage of the gas in all producing wells in a section, including wells that had been drilled before the date of the Original Agreement. In Downdip sections NW Natural also received an additional interest in the specific well drilled. For this reason, if the specific well drilled produced significantly less than expected, the risk was mitigated as the Company would receive an increased percentage of other producing wells and so would still be compensated to a significant extent. For post-carry wells, NW Natural receives an interest in the output of only the specific well drilled. Therefore, if a post-carry well produces 50% of forecast volumes, and comes in at the expected cost, the value received by NW Natural for that specific investment will be 50% of that expected.

The second difference pertains to the risk in development costs. While NW Natural bears only its own pro rata share of capital investment in each post-carry well, the cost is not capped, as it was for carry wells. The deal does not mitigate the risk that capital costs will exceed estimates.

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Q. Is there an agreed-upon schedule for the development of the post-carry well locations in Sections 32, 33, and 34?

A. There is no set drilling schedule for the development of post-carry wells. Instead, either NW Natural or Jonah Energy can propose the development of any well location. As a practical matter, because Jonah Energy is the operator of the field, it is likely that only Jonah Energy would be the "proposer."

Q. What is the process to develop additional post-carry well locations?

A. Once Jonah Energy proposes to drill a well, NW Natural can choose whether to participate in the development of the well. Typically, NW Natural will have 30 days to consent to a proposed well unless a drilling rig is on site. If a drilling rig is on site, then NW Natural must consent within 48 hours.

Q. What happens if NW Natural consents?

A. If NW Natural consents, then NW Natural must pay its "working interest" share of the costs to drill, complete, and equip the well. That means that NW Natural pays costs on the same basis on which it is entitled to the gas in the relevant section-- 45% in section 33 and 49% in section 34, for example. Once the well is operational, NW Natural will pay its working interest share of the costs to operate the well, and will receive its pro rata share of the gas.

Q. What happens if NW Natural does not consent?

A. If NW Natural does not consent, the Company will forego NW Natural's share of gas from that well until Jonah Energy's proceeds from the sale of that gas equal 200 percent of what would have been NW Natural's capital share of the development costs. At that point, NW Natural will receive any subsequently-

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produced gas from that well based on the Company's pro rata share of the gas for the relevant section. Importantly, based on volume forecasts, NW Natural does not ascribe significant value to this right.

IV. CONSENT ANALYSIS FOR POST-CARRY WELLS

Q. How did NW Natural analyze the nine new well proposals to determine whether the Company should consent and participate in the drilling?

A. Like the original carry wells, the new post-carry wells would act as long-term hedges in our gas portfolio. For that reason, the Company considered the threshold question as to whether it made sense for us to continue to enter into additional long-term hedges on customers' behalf. In the Commission's order approving the Original Agreement, the Commission recognized that over the next 10 years the transaction would, on average, provide 10 percent of the Company's annual gas supply. However, the Company had terminated the carry well program, and for that reason, the amount of its portfolio invested in long-term hedges was expected to fall well below 10 percent over the succeeding years. Investment in post-carry wells would help maintain the percentage of long-term hedges in NW Natural's portfolio closer to ten percent for a few additional years.

We then determined whether the post-carry wells represented a good deal for customers. To answer this question, we compared the expected cost of gas from each of the proposed wells to the benchmark cost of a 10-year financial hedge (including the cost of a credit facility). If the forecast cost of gas from the proposed well was lower than the cost of a 10-year hedge, then the Company

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consented to participate in the well. This is the same basic approach that the Company used to analyze the decision to enter into the Original Agreement.

Q. How did the Company calculate the costs of gas from the proposed wells?

A. Estimating the cost of gas is a two-step process. First, we estimated the costs, both capital and ongoing, that would be incurred to drill and operate the wells. Like the cost modeling for the original Encana deal, the cost modeling here includes three components: operating costs; depletion costs, and carrying costs. The cost of gas is the sum of these three components and is modeled by month over the expected life of each well. We then divide these costs by the expected volumes each month to develop a cost per therm, which allows a direct comparison to the benchmark 10-year hedge price.

Q. Please describe the operating costs.

A. Operating costs are variable costs that reflect the costs of actually operating the wells to provide NW Natural with its share of the gas output. The cost components for the day-to-day operation of the wells include daily site visits, maintenance of pumps and equipment, and water disposal issues, among other activities. This cost is allocated to us at our ownership share in a section. We will be charged the operating costs of the specific new well in addition to the overhead costs that are allocated to each well.

In addition, the operating costs include severance and ad valorem taxes levied by the state of Wyoming, which are based on the volumes produced, the market price, and the tax rate. The operating costs also include midstream costs, which are the costs of gathering and processing the gas between the

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wellhead and the interstate pipeline. The midstream and gathering costs and taxes have a direct relationship to the gas being produced and we have continued to use the same formulae that we have found to be accurate in our original Encana deal.

The operating costs are estimated by NSAI and corroborated by our experience with the operation of wells in the Jonah Field thus far.

Q. Please describe the depletion costs.

A. Depletion cost is essentially amortization and is based on the total capital cost of the wells. It is calculated on a dollar per therm basis and recorded based on volumes produced. For example, if the Company spends $1.5 million to drill a well and is expected to receive 10 million therms over the life of the well, the depletion rate would be 15 cents per therm.

Q. Please describe the carrying costs.

A. As described above, the Company will be funding its share of the capital costs Jonah incurs in drilling the wells. Carrying costs are the financing costs incurred by the Company to fund the capital investment. By including carrying costs in the cost of this gas we are assuming recovery of our regulated return on this investment.

Q. Did the Company use more than one approach to estimate expected volumes from the proposed wells?

A. Yes, we used three approaches to estimate projected costs of gas.

- **First** we estimated volumes by looking at NSAI's average forecasts for the remaining undrilled economic wells—or Proved Undeveloped reserves

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("PUDs")—for the sections in which we would be drilling. We called this the **"Section Average"** approach. NSAI's gas volume modeling is based on a type curve, or a "PUD profile". The PUD profile projects the expected gross gas volume from the wells in a section on average and displays the result as a volume string for one well by month over the forecasted life of a well. To determine NW Natural's expected volumes, we multiplied total volumes by the Company's net ownership interest in the applicable section. The net ownership interest is a function of the Company's ownership percentage in the section less the royalties that will be paid. This calculation yields the net gas that would be produced under our interest.

- **Second,** we estimated volumes by looking at the forecast provided by NSAI for the individual well proposed for drilling. We called this the **"Individual Well"** approach. As discussed above, NSAI uses a type curve to estimate production from each PUD in a section. Instead of averaging these estimates, as in the Section Average Approach, for the Individual Well approach we simply looked at the forecast for the individual well proposed.
- **Third**, we used the actual volumes produced by the carry wells in which NW Natural had participated to date to estimate expected volumes for future post-carry wells on a section average basis. We referred to this as the **"Historical Performance"** approach**.**

We consented to participate in the drilling of an individual proposed post-carry well if the highest of the three forecast costs of gas for that well was less than the benchmark 10-year hedge.

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Q. What did you use for price comparisons for the long-term gas hedge?

A. As the majority of the gas volumes from these wells are expected to be produced in the first 10 years of the well's life, we used quotes for 10-year financial derivative swaps. We obtained quotes from two financial counterparties for 10-year swaps which came in at $4.35 per dekatherm and $4.545 per dekatherm, respectively.

In addition to the price of the hedge itself, we also considered the additional cost the Company would incur if it purchased financial hedges to secure an appropriate credit facility. The credit facility is essentially an insurance policy which is necessary to protect the Company and customers in the event that the counterparty to the 10-year hedge is unable to fulfill its end of the obligation. For this reason, the estimated cost of a credit facility of 18 cents per dekatherm is added to the hedge quote, producing a total long-term hedge benchmark price range between $4.53 and $4.725.

Based on the above, and current gas price forecasts, we determined that any post-carry well forecast to produce 1.6 Bcf of gas or better would be economical compared to a long-term financial hedge.

Q. Please describe the analysis for the first four proposed post-carry wells.

A. The Company received the proposals for the first four post-carry wells—all located in Section 34—at about the same time. As discussed above, and as with all of the post carry wells proposed, we looked at volumes using all three approaches—*Section Average, Individual Well* and *Historical Performance*. We performed the *Section Average* test for these wells by looking at the combined

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averages of Sections 33 and 34. For the *Historical Performance* approach we used our own calculations of future volumes based on NSAI data showing the performance of the carry wells drilled to date. All of the analyses – as summarized below-- supported the decision to consent. [3]

Well Number	Section Average	Historical Performance	Individual Well	Hedge Benchmark[4]	Economic or Non-economic
83-34	$0.322	$0.363	$0.290	$0.435 - $0.455	Economic
98-34	$0.322	$0.363	$0.294	$0.435 - $0.455	Economic
84-34	$0.322	$0.363	$0.315	$0.435 - $0.455	Economic
97-34	$0.322	$0.363	$0.328	$0.435 - $0.455	Economic

Q. Please describe the analysis for the fifth well proposed?

A. The fifth well was located in Section 33. As with the first four wells, we performed the *Individual Well* test, and we performed the *Section Average* test by combining the averages from Sections 33 and 34. For the *Historical Performance*

[3] In addition to these analyses we also performed the NPV calculation and evaluated the value of the gas that we might receive if we did not consent As discussed above, under the agreement, if the Company decided not to participate in a post-carry well, it would forego its share of gas from that well until Jonah Energy's proceeds from the sale of gas from that well equaled 200 percent of what would have been NW Natural's capital share of the development costs. These tests supported the Company's decisions to consent in all cases.

[4] At the time we ran the analysis, we did not add the credit facility to the cost of the hedge.

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approach, we did not at this point have historical data for Section 33 and so we performed our projections of future volumes based on the performance of the carry wells drilled to-date in Section 34. Also, at this point we received some information from NSAI that prompted us to make corrections to the way we were applying their type curve information. All three approaches indicated that we should participate in drilling this well, and we therefore consented.

Well Number	Section Average	Historical Performance	Individual Well	Hedge Benchmark	Economic or Non-economic
109-33	$0.369	$0.387	$0.412	$0.435 - $0.455	Economic

Q. Please describe the analysis for the sixth through ninth wells proposed?

A. NW Natural received the proposals for wells six through nine close in time and conducted the analysis for these wells at the same time. Two of these proposed wells are in Section 33 and the other two are in Section 34. By this point we had determined that we could improve the validity of the *Section Average* approach by looking at each section individually. Accordingly, we used the Section 34 average volume for wells in Section 34, and Section 33 average volume for wells in Section 33. In addition, for the *Historical Performance* test, instead of performing our own forecasts based on historical data as we had for the first five wells, we substituted NSAI forecasts based on historical data, which we judged to be more accurate. Based on this analysis, we consented to the two wells in Section 34 and non-consented to the two wells in Section 33.

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Well Number	Section Average	Historical Performance	Individual Well	Hedge Benchmark	Economic or Non-economic
99-33	$0.398	$0.525	$0.573	$0.453 - $0.473	Non-economic
72-34	$0.359	$0.387	$0.338	$0.453 - $0.473	Economic
41-33	$0.398	$0.525	$0.572	$0.453 - $0.473	Non-economic
105-34	$0.359	$0.387	$0.347	$0.453 - $0.473	Economic

Q. It appears that by the time the Company analyzed the sixth through ninth wells, it had acquired more information from NSAI and had refined its methodologies. Have you performed an analysis to determine whether the Company would have made different decisions had it refined its approach *prior* to considering whether to drill the first five wells?

A. Yes, we did. To answer the question, we updated our analyses and included the more refined data we ultimately obtained from NSAI. In particular, we revised the following inputs for the first four wells:

(a) We corrected our application of NSAI's type curve information in all analyses;

(b) for the *Section Average* calculation, we used the section average value corresponding to the section in which the specific well was located; and

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(c) for the *Historical Performance* calculation we substituted NSAI-calculated data for the historical calculations initially performed by the Company.

As you can see, an analysis using the updated data supports our decision to participate in drilling the first four wells.

Well Number	Section Average	Historical Performance	Individual Well	Hedge Benchmark	Economic or Non-economic
83-34	$0.359	$0.387	$0.335	$0.453 - $0.473	Economic
98-34	$0.359	$0.387	$0.340	$0.453 - $0.473	Economic
84-34	$0.359	$0.387	$0.366	$0.453 - $0.473	Economic
97-34	$0.359	$0.387	$0.384	$0.453 - $0.473	Economic

For the fifth well, we revised the following inputs:

(a) For the *Section Average* calculation, we used the section average value corresponding to the section in which the specific well was located; and

(b) for the *Historical Performance* calculation we substituted NSAI-calculated data for the historical calculations initially performed by the Company.

As you can see, the results of this refined analysis supported our decision to consent to the fifth well using the *Section Average* and *Individual Well* approaches, but not using the *Historical Performance* test.

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Well Number	Section Average	Historical Performance	Individual Well	Hedge Benchmark	Economic or Non-economic
109-33	$0.398	$0.525	$0.429	$0.453 - $0.473	Mixed result

V. EARLY RESULTS FROM WELLS DRILLED

Q. Has the Company received any early reports on the performance of the seven wells in which it participated?

A. The Company periodically receives raw production data from Jonah Energy. Although it is still somewhat early in the production life of these wells, the initial volumes received from the seven wells has been materially below expectations. In October, when we received requests to consent to an additional two wells, the production data we were receiving was low enough that we decided that we needed to call a "time-out" on drilling until we got more information.

Q. What actions did the Company take?

A. First, we contacted Jonah Energy to request that it withdraw its request for consent to the two wells proposed in October 2014 that were still under consideration, to give us more time to investigate and to determine the prudent course. However, Jonah Energy had already moved rigs into place and, therefore, declined to withdraw the request, and proceeded to drill these two wells on its own.

Second, because the initial volumes raised a red flag, the Company questioned whether the disappointing initial volumes would be indicative of

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overall lower-than-expected results. The Company questioned whether these wells would produce at a lower rate but not experience the same annual decline as the rest of the field. To answer our questions, NW Natural engaged NSAI to conduct additional analysis to (a) identify the causes for the underperformance; (b) determine whether the recent data suggested that its volume and market value forecasts for new wells should be revised; and (c) review the Company's criteria for future consents based on revised assumptions or forecasts.

Q. Has NSAI completed its analysis?

A. Yes. NSAI provided the Company with the preliminary results of its analysis. In summary, NSAI found the following:

- Recent wells drilled in the north and east sections of Jonah Field have performed as forecast in terms of volume, the rate at which gas volume declines over time, and the percentage of the gas in place that could be recovered with current practices. However, recent wells drilled in the south and west sections*, where Sections 32, 33 and 34 are located*, have performed differently from the rest of the field.
- As a result of its analysis, NSAI updated its methodology for the south and west sections of Jonah field (the methodology for the north and east sections remained unchanged) resulting in lower total forecast economic production from the additional wells in Sections 32, 33 and 34;

Q. What does this mean for the volumes that NW Natural can expect from the carry and post-carry wells it has drilled to date?

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A. Fortunately, NSAI's findings do not affect the expected volumes from the original 72 carry wells drilled by NW Natural. While, as explained above, these wells have been performing below original expectations, NW Natural received an adjustment to its ownership interest when we entered into the Second Amendment with Encana. With that adjustment, NW Natural is receiving the volumes forecast when we entered the Original Agreement. On the other hand, NSAI, has revised downward its volume projections for the post-carry wells quite substantially. NSAI is now projecting that the post-carry wells drilled to date will produce on average 1.1 Bcf—well below our 1.6 Bcf break-even threshold.

Q. Has the Company calculated the forecast cost of the gas from the post-carry wells drilled to date based on this new data?

A. Yes. We have incorporated NSAI data and current actual capital costs into our forecast to calculate the cost of gas produced from the post-carry wells drilled to date. We currently forecast that the gas will come in at an average of $0.664 per therm. This forecast assumes an average well production of 1.1 Bcf and total capital costs of $10.8M.

Q. Given the revised volume forecasts is it possible that the Company might consent to any additional post-carry wells that may be proposed in the future?

A. Yes, but only in the event of significant price increases--in which case these wells could prove a valuable hedge.

Q. Does this conclude your testimony?

A. Yes.

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BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UM ____

NW Natural

Direct Testimony of C. Alex Miller

February 26, 2015

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I. INTRODUCTION AND SUMMARY

Q. Please state your name and position with Northwest Natural Gas Company ("NW Natural" or the "Company").

A. My name is C. Alex Miller. My current position is Treasurer and Vice President of Regulation for NW Natural. I am responsible for Rates & Regulatory Affairs, as well as Treasury operations.

Q. Please summarize your educational background and business experience.

A. I received a B.A. in economics from the University of Oregon in 1980. I received an M.B.A. from Claremont Graduate School in 1984. From 1981 through 1997, I worked at Southern California Edison in various rate and finance positions, including Vice President and Treasurer. From 1997 to 2001, I worked at PacifiCorp in various positions, including Vice President of Business Development. I joined NW Natural in 2002.

Q. What is the purpose of your testimony?

A. The purpose of my testimony, along with the testimony of Barbara Summers, is to provide the Public Utility Commission of Oregon ("Commission") with sufficient information and analysis to determine that the Company's decision to participate in the drilling of certain post-carry wells, pursuant to its Second Amended Agreement with Encana Oil & Gas (USA), Inc. ("Encana")[1] is prudent, and that the costs of the gas received under this arrangement should be recoverable

[1] As discussed in the Testimony of Barbara Summers, Encana sold its interest to Jonah Energy, LLC.

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through customer rates through NW Natural's Purchased Gas Adjustment mechanism ("PGA").

I will also explain the Company's cost of service calculations, its proposed ratemaking, and accounting treatment for the Company's investment in and operation of the post-carry wells.

II. NW NATURAL'S ACTIONS DURING ANALYSIS OF POST-CARRY WELLS

Q. When did Jonah Energy first propose the drilling of post-carry wells and what was NW Natural's initial response?

A. In April of 2014, Jonah Energy first notified NW Natural that it intended to propose four carry wells in the near future, and that it might propose additional wells in the following months. In response, NW Natural began evaluating the economics of the potential post-carry wells using data provided by Netherland Sewell & Associates, Inc. (NSAI)—the oil and gas consultants that provided well forecasts used to evaluate the original transaction with Encana ("Original Agreement"). Based on NSAI's forecasts for the post-carry wells and NSAI's actual historical data from our carry wells, NW Natural came to the conclusion that the first four post-carry wells, overall, presented an attractive hedging opportunity for its customers.

At the same time, however, NW Natural viewed the risks raised by participation in the post-carry wells as significantly higher than participation in the carry wells. When the Company invested in drilling a carry well, it had received an increased ownership percentage in all producing wells in the section, including those that had been drilled prior to the date of the Original Agreement.

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Accordingly, any risk that the specific well drilled might underperform was mitigated by the increased interest in the other producing wells. On the other hand, when the Company invests in a post-carry well, it receives an interest only in that particular well; as a result, the decision to invest in a particular post-carry well presents a more concentrated risk.

Q. Given NW Natural's evaluation of the benefits and risks of the post-carry wells, what actions did it take?

A. NW Natural developed a written proposal for the regulatory treatment of the post-carry wells opportunity. NW Natural provided this proposal to stakeholders—OPUC Staff, CUB, and NWIGU—and met with them to describe the opportunity, and to seek their views on whether they believed NW Natural should pursue these wells as part of its gas supply strategy.

Q. What was NW Natural's proposal to the stakeholders?

A. NW Natural presented a primary proposal and an alternative for stakeholders to consider. NW Natural's primary proposal was to participate in the post-carry wells on a non-regulated basis, and then to provide all relevant data from the post-carry wells to the stakeholders and Commission, so that they could better assess the risks and opportunities presented by the post-carry wells drilling opportunity in the Jonah Field.

NW Natural's secondary proposal was to include the costs in rates in the same manner as the costs of the Original Agreement.

Q. Can you explain the reasons for NW Natural's primary proposal?

A. Yes. First, as discussed above, NW Natural noted that the different deal structure for the post-carry wells meant that NW Natural will be required to bear

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'dry hole' risk and that NW Natural would bear all of the price risk associated with our proportionate share of the wells.

Second, we explained that NW Natural was required to make a decision about whether to participate in the wells within 30 days from the date proposed, and that it would be difficult for the parties to fully evaluate the risks and benefits in such a short timeline.

In light of these factors, we proposed that:

1. NW Natural participate in the drilling of the post-carry wells proposed by Jonah Energy on a non-regulated basis, without requesting cost recovery through the PGA, and consequently having the Company accept all of the risks and benefits associated with the wells;
2. NW Natural would make available to the Commission and stakeholders all of the information about the wells, their performance and cost; and
3. NW Natural would seek to open a docket in the future in which this information could be reviewed, and where more time could be taken to determine whether future wells should be added to NW Natural's resource portfolio.

Q. Why did NW Natural believe it would be appropriate to participate in the post-carry wells on a non-regulated basis?

A. We believed it would be appropriate only in the circumstances that were presented, which involved making a very quick decision to participate in an untested arrangement. We believed it presented a fair way to gain information and experience with the post-carry wells without presenting risk to customers, but in a way that preserved the potential benefits for customers of further drilling in the Jonah Field.

Q. Was NW Natural willing to bear all of the risks of the post-carry wells in the primary proposal?

A. Yes, NW Natural was willing to bear all of the risks of the post-carry wells to the extent that the Company would also receive the potential benefits. It would not have been reasonable for NW Natural to enter into a one-sided arrangement to bear the risks but not receive the benefits of its investment.

Q. How did the stakeholders react to NW Natural's primary proposal?

A. They rejected the proposal. Representatives from Staff, CUB, and NWIGU all indicated that they could not support NW Natural participating in the wells on a non-regulated basis. Instead, they stated their belief that the opportunity to participate in the post carry wells was a utility asset, and that to the extent it was prudent to participate in the wells, the costs and benefits should be included in customers' rates.

Q. How did NW Natural respond to the stakeholders' position?

A. We stated that we could agree to participate in the post-carry wells on a regulated basis if there was a clear understanding of the regulatory context. Specifically, we wanted to make sure that all agreed that the prudence of the Company's decisions—and ultimate rate recovery of any costs incurred—would be based on the reasonableness of the Company's actions based on the information available at the time. In short, we wanted to make sure that drilling decisions were not judged in hindsight based on the results achieved.

Q. How did the parties resolve the issue?

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A. The parties agreed that the costs and benefits of the post-carry wells should be included if the Company acted prudently regardless of the outcome. We entered a Memorandum of Understanding (MOU) to memorialize this agreement, attached as NWN/201, Miller.

Q. What does the MOU say?

A. The MOU describes the context surrounding the post-carry wells opportunity, sets forth some agreements on process, and documents the parties' agreement on other key issues, which include:

1. Pursuant to the Second Amended Agreement, Jonah Energy presented NW Natural with a necessary, time-sensitive decision with respect to whether it would participate in the post-carry wells;
2. NW Natural's decision to participate in the post-carry wells will be subject to a prudence determination, and that the parties will take a position on prudence consistent with the Commission's established standard for judging prudence;
3. If NW Natural's decision to participate in the post-carry wells was prudent, then the costs, including the associated capital costs, and benefits should be included in customers rates through the PGA, as was done under the Original Agreement; and
4. NW Natural will track the costs and production of gas from the post-carry wells separately from the wells drilled under the Original Agreement, to facilitate review and monitoring of the post-carry wells' performance.

Q. After the MOU was signed, what did NW Natural do?

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A. We continued to refine our analysis of the opportunity and, based on that analysis, made the decision to drill 7 of the 11 post-carry wells presented to us by Jonah Energy as of this date. That analysis and the decisions made are described in the testimony of Barbara Summers.

III. REGULATORY CONSTRUCT

Q. What action is NW Natural requesting the Commission take?

A. NW Natural is seeking a Commission order that:

1) Establishes that NW Natural's actions in participating in the seven post-carry wells were prudent; and
2) Orders that the costs of the gas produced by the post carry wells will be included in the PGA in the same manner as the carry wells, as approved in UM 1520.

Q. How has NW Natural demonstrated that its actions were prudent?

A. The testimony of NW Natural witness, Barbara Summers, demonstrates the prudence of NW Natural's actions. Specifically, Ms. Summers describes the analysis NW Natural undertook to inform its decisions to invest in the seven post-carry wells. In taking this approach, NW Natural acted reasonably, in good faith, and in a manner that satisfies the Commission's prudence standard.

Q. What ratemaking methodology should be used for including the costs of the post-carry wells in rates?

A. The same methodology that was used for the ratemaking under the original Carry and Earnings Agreement with Encana works for the post-carry wells. That methodology placed into rates each year the cost of service associated with the production of the gas from the Jonah Field.

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Q. What comprises the cost of service included in rates under that approach?

A. The cost of service includes depletion costs, carrying costs, operating costs, severance and ad valorem taxes, and midstream costs.

Q. Under the ratemaking approach you describe above, would there be any sharing of cost variations by NW Natural?

A. As implemented for the original carry wells,, NW Natural would share its regular PGA sharing percentage (*i.e*. either 10% or 20%) of the costs, to the extent those costs vary from the amount that is updated and included in the PGA each year, up to the first $10 million of the variance in any annual period, whether that variance is positive or negative. All variance in excess of $10 million (whether positive or negative) would be passed through to customers through the PGA.

Q. Do you anticipate that the variance in an annual period could exceed $10 million?

A. No, the Company does not anticipate that the variances will exceed $10 million. The volumes of gas involved from seven wells will simply be too small to reach such a high variance.

Q. Can you provide the Company's current forecast of the cost of gas from the post-carry wells drilled to date?

A. Yes, as explained more fully in the testimony of Barbara Summers, the Company currently forecasts that the average cost per therm of the gas from the seven post-carry wells is $0.664.

Q. How will customers' rates be impacted by the post-carry wells based on the Company's forecasts?

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A. In relation to the Company's WACOG, the forecasted volumes of gas from the post-carry wells is nominal compared to the Company's total throughput and would have a negligible impact on customers' rates. If the rate impact of the seven post-carry wells is analyzed in combination with the 72 carry wells, the overall forecasted cost of gas of the 79 wells is $0.538. This figure is meant for illustrative purposes only; the Company is accounting for the post-carry wells on a separate basis from the carry wells.

IV. FUTURE GAS RESERVES TRANSACTIONS

Q. Is NW Natural intending to pursue additional gas reserves transactions in the future?

A. NW Natural is currently conducting analysis to determine the parameters of future long-term hedging opportunities. To the extent that this analysis shows that long-term hedging continues to be a valuable gas supply strategy, we believe that gas reserves may be an important tool in achieving those long-term hedges. For the reasons described in the testimony of Barbara Summers, we do not anticipate that continued drilling of the post-carry wells in the Jonah Field would be the method of obtaining those reserves.

Q. Does this conclude your testimony?

A. Yes.

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MEMORANDUM OF UNDERSTANDING REGARDING RATE TREATMENT OF ELECTIVE NON-CARRY WELLS

This Memorandum of Understanding is entered into by NW Natural Gas Company (NW Natural), Citizens' Utility Board of Oregon (CUB); Northwest Industrial Gas Users (NWIGU) and the Staff of the Public Utility Commission of Oregon (Commission) (collectively, the Parties).

I. Recitals

Whereas, NW Natural and Encana Oil & Gas (USA) Inc., (Encana) entered into a Carry and Earning Agreement (Agreement) to develop certain gas reserves in the Jonah Field in Sublette County, Wyoming, for the benefit of NW Natural's utility customers. The Agreement called for NW Natural and Encana to jointly fund the drilling of 102 "carry wells" and in return NW Natural would receive a share of the gas produced in specific sections of the field. In addition, after the drilling of the carry wells had been completed, NW Natural would have the opportunity to participate in the drilling of additional elective "non-carry wells." For each non-carry well for which NW Natural helped fund the drilling, NW Natural would receive a percentage of the gas produced from that specific well;

Whereas, in consolidated dockets UM 1520 and UG 204, NW Natural requested approval of the Agreement from the Public Utility Commission of Oregon (Commission). In those dockets the Parties entered into a Stipulation requesting that the Commission find the Agreement prudent, subject to conditions and qualifications, and requesting that the Commission approve certain ratemaking treatment for the costs of the transaction;

Whereas, on May 25, 2011, the Commission issued Order No. 11-176, adopting the Stipulation and clarifying that its prudence finding applied to only NW Natural's decision to enter into the Agreement and not to any subsequent decisions NW Natural might make in exercising its discretion to manage the Agreement;

Whereas, NW Natural (through NW Natural Gas Reserves) and Encana have drilled 72 of the 102 carry wells;

Whereas, NW Natural informed the Parties that on March 28, 2014, Encana signed an agreement to sell its interests in the Jonah Field to an affiliate of TPG Capital (TPG) for a purchase price of approximately $1.8 billion;

Whereas, in March 2014 NW Natural and Encana executed an amendment to the Agreement, terminating NW Natural's obligation to participate in the drilling of the last 30 carry wells and NW Natural's associated required funding;

Whereas, NW Natural has informed the Parties that due to the amendment to the Agreement, 30 of the original 102 carry wells will not be developed pursuant to the terms of the Agreement; and there were also an additional eight carry wells that would have been left undeveloped even if the drilling program had been completed. These undeveloped well locations are now considered non-carry wells, and NW Natural or Encana/TPG can propose development of any non-carry well location under the amended Agreement and once proposed, the other party can choose to consent or not consent to participating in the development of the well(s);

Whereas, NW Natural has informed the Parties that TPG has now proposed to NW Natural that it participate in the development of certain non-carry wells and NW Natural is currently analyzing the proposal; and

Whereas, the Parties wish to confirm the regulatory framework for the Company's decision.

Therefore, the Parties agree as follows:

1. NW Natural's determination as to whether it will participate in the funding of the four proposed non-carry wells—and any future non-carry wells—is a decision NW Natural must make in managing the Agreement. Consistent with the Commission's Order 11-176, NW Natural's decision has not been preapproved for prudence.

2. If Northwest Natural does decide to participate in non-carry wells, now or in the future, the decision to do so will be subject to a prudence determination. NW Natural agrees to submit its request for a prudence determination to the Commission separate from its PGA filing. NW Natural further agrees that its request for a prudence determination will be accompanied by supporting testimony and related documents. The Commission set forth its standard for determining prudence in its Order No. 12-493 at 25-27 and the Parties will use this standard in supporting their respective recommendations in the prudence determination.

3. If the Commission determines that NW Natural's decision to participate in a non-carry well or wells was prudent, the Parties agree that NW Natural may include the costs and benefits of the non-carry well(s) as part of its hedged gas reserves and include as such in the WACOG in the next PGA after the prudence determination, as was done with the gas associated with the Agreement prior to its amendment. All parties recognize that the need for a separate prudence determination likely eliminates the possibility that prudently incurred costs will be included in this year's PGA filing. In this and future years, to the extent the timing of NWN's request for prudency determination does not give the parties sufficient time for review before the PGA, NWN may file for a deferral but Staff and the Intervenors take no position as to their support or opposition for such a filing if made.

4. NW Natural also agrees that it will track the costs of, and production of gas from, the non-carry wells as a line item separate from the wells previously drilled under the Agreement, to facilitate review and monitoring of the non-carry well activity.

PARTY NW Natural

By: [signature]

Date: 7-15-2014

PARTY

By: ______________________

Date: ______________________

PARTY

By: ______________________

Date: ______________________

PARTY

By: ______________________

Date: ______________________

PARTY

By: Mike [signature]

Date: Attorney for PUC Staff
7/15/14

PARTY

By: ______________________________

Date: ______________________________

PARTY

By: ______________________________

Date: ______________________________

PARTY

By: ______________________________

Date: ______________________________

PARTY Citizens' Utility Board

By: ______________________________

Date: 7-16-14

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PARTY Northwest Industrial Gas Users

By ____________

Date ___ 15 14

CONSTELLATION NEWENERGY-GAS DIVISION, LLC

EXHIBIT SB-4

OF

STEPHEN BENNETT DIRECT TESTIMONY

IN THE MATTER OF THE APPLICATION OF BLACK HILLS NEBRASKA GAS UTILITY COMPANY, LLC D/B/A BLACK HILLS ENERGY FOR APPROVAL OF ITS GAS HEDGE AGREEMENT WITH BLACK HILLS UTILITY HOLDINGS, INC.

APPLICATION NO. NG-0086

COMMONWEALTH OF VIRGINIA

STATE CORPORATION COMMISSION

AT RICHMOND, NOVEMBER 6, 2015

APPLICATION OF

WASHINGTON GAS LIGHT COMPANY

CASE NO. PUE-2015-00055

For approval of a Natural Gas Supply Investment Plan pursuant to § 56-609 of the Code of Virginia

ORDER ON APPLICATION

On May 12, 2015, Washington Gas Light Company ("WGL" or "Company") filed with the State Corporation Commission ("Commission") an application ("Application") for approval of a proposed Natural Gas Supply Investment Plan ("Plan") in accordance with § 56-609 of the Code of Virginia ("Code").

In its Application, the Company proposes to consummate a transaction with Energy Corporation of America to acquire a non-operating, wellbore working interest in natural gas producing wells in the Marcellus Shale region. The Application states that the Company would make an approximately $122 million investment to acquire an approximate 96% working interest in proved gas reserves in 22 wells in Greene County, Pennsylvania, and three wells in Clearfield County, Pennsylvania.[1] The gas reserves acquired through the Plan would partially replace base gas commodity purchases the Company would otherwise make.[2] The Plan will also provide for the gathering, transportation and receipt of these gas reserves over a 20-year period.[3] The recovery of the costs associated with the Plan would be coordinated with the production and

[1] Application at 1.

[2] *Id.*

[3] *Id.* at 1-2.

receipt of the natural gas over 20 years.[4] The Company asserts that the Plan meets all the requirements of Code § 56-609 and is in the public interest in that it offers reasonably anticipated benefits to its Virginia customers in the form of savings in the delivered costs of gas versus current long-term forward market projections.[5] The Company further asserts that the Plan also benefits Virginia customers by reducing the Company's overall portfolio price volatility and overall supply risk for base gas volumes.[6]

On June 3, 2015, the Commission issued an Order for Notice and Hearing that, among other things, established a procedural schedule for this case and directed WGL to provide public notice of this matter. The Commission held a public evidentiary hearing on September 30 and October 1, 2015. The following participated at the hearing: WGL; the Office of the Attorney General's Division of Consumer Counsel ("Consumer Counsel"); and the Commission's Staff ("Staff"). No public witnesses appeared to testify at the hearing. On October 9, 2015, WGL, Consumer Counsel, and Staff filed post-hearing briefs.[7]

NOW THE COMMISSION, upon consideration of this matter, is of the opinion and finds that the specific Plan as proposed in the Company's Application is not in the public interest, and, therefore, the Application is denied.

---

[4] *Id.*

[5] *Id.*

[6] *Id.*

[7] On October 14, 2015, WGL filed a Proffer that proposed changes to the Plan. On October 27, 2015, the Commission issued an Order finding that due to the time limitations imposed by statute for this proceeding, as well as other procedural requirements meant to provide all participants a full opportunity to address all issues, it is neither practical nor possible at this late stage to re-open the record, hold additional evidentiary hearings, and consider fairly the Proffer.

Code of Virginia

This case involves the first application that has been filed pursuant to Code § 56-609, which provides as follows:

> A) As used in this section, unless the context requires a different meaning: "Eligible natural gas supply infrastructure costs" includes the investment in eligible natural gas supply infrastructure projects and the following:
>
> 1) Return on the investment. In calculating the return on investment, the Commission shall use the natural gas utility's then in effect weighted average cost of capital, including the cost of debt and equity, based on its regulatory capital structure used in determining the natural gas utility's base rates. The investment will be multiplied by the weighted average cost of capital to determine the return on investment;
>
> 2) A revenue conversion factor. Such factor, including income taxes, shall be applied to the required operating income resulting from the eligible natural gas supply infrastructure costs;
>
> 3) Operating and maintenance expense, which includes the amount of operating and maintenance expense utilized in production wells, processing the gas produced, and gathering, transmission, and distribution lines delivering the gas to a pipeline or distribution system;
>
> 4) Depreciation. In calculating depreciation, the Commission shall use the natural gas utility's current depreciation rates for investments in distribution infrastructure, as set out by appropriate asset class. The utility shall propose a basis for recovering for the depreciation or depletion of investments in other asset classes in the natural gas supply investment plan, including investments in natural gas reserves that will deplete based on their useful life or of associated facilities that may be retired upon depletion of natural gas reserves;
>
> 5) Property tax, severance tax, and any other taxes or government fees associated with production and transmission of natural gas; and

6) Carrying costs on the over-recovery or under-recovery of the eligible natural gas supply infrastructure costs. In calculating the carrying costs, the Commission shall use the natural gas utility's regulatory capital structure as determined in subdivision 1 of this definition.

"Eligible natural gas supply infrastructure projects" means capital investments in natural gas reserves and upstream pipelines and facilities that, alone or in combination with other projects or strategies, offer reasonably anticipated benefits to customers and markets, which benefits mean (i) savings in the delivered cost of gas versus long-term forward market projections available to the natural gas utility at the time of the capital investment or other alternatives, (ii) a reduction in the utility's overall portfolio price volatility, (iii) reduction in the utility's overall supply risk, or (iv) any combination of the savings or reductions described in clauses (i), (ii), and (iii). Any such customer benefit benchmarks shall be outlined in the natural gas utility's filings with the Commission pursuant to this section.

"Investment" means actual costs incurred on eligible natural gas supply infrastructure projects, including planning, development, and construction costs; actual costs of infrastructure associated therewith; and an allowance for funds used during construction. In calculating the allowance for funds used during construction, the Commission shall use the natural gas utility's actual regulatory capital structure as determined in subdivision 1 of the definition of eligible natural gas supply infrastructure costs.

"Natural gas reserves and upstream pipelines and facilities" means investments in natural gas reserves, production facilities (including equipment required to prepare the natural gas for use), gathering, transmission, and, within the natural gas utility's certificated service territory, any distribution pipelines necessary to deliver the reserves, and above-ground and below-ground storage used in the delivery of gas to existing natural gas transmission pipelines or distribution systems.

"Natural gas supply investment plan" means a plan filed by a natural gas utility that identifies proposed eligible natural gas supply infrastructure projects and its development of those projects with or without a third party.

B) A natural gas utility shall have the right to recover eligible natural gas supply infrastructure costs on an ongoing basis through the gas cost component of the utility's rate structure or other recovery mechanism approved by the Commission, provided that any such mechanism shall properly allocate costs. Natural gas utilities using the cost of service methodology set forth in § 56-235.2 or a performance-based regulation plan authorized by § 56-235.6 shall be eligible to file a plan. The plan shall include a timeline for the investment and completion of the proposed eligible natural gas supply infrastructure projects; provide for an estimated schedule for recovery of the related eligible natural gas supply infrastructure costs through the gas cost component of the utility's rate structure or other mechanism, including proposed depreciation rates for investments in non-distribution asset classes and how any revenue gains from the use of the pipelines by third parties will be used to offset eligible natural gas supply infrastructure costs; and demonstrate that the plan is in the public interest with due consideration to providing a portion of the utility's delivered supply at prices at or below the long-term projections as available and defined in the natural gas utility's filing, or reduction in the utility's overall supply risk, or reduction in the utility's overall portfolio price volatility, or a combination thereof. No project may provide an annual volume of natural gas that exceeds 12.5 percent of the natural gas utility's annual firm sales demand, and no combination of projects may provide an annual volume of natural gas that exceeds 25 percent of the natural gas utility's annual firm sales demand. The natural gas utility's weather-normalized firm sales demand for the calendar year preceding the application shall be deemed to establish the annual firm sales demand for the purposes of calculating the volume and volumetric limits of projects. In no case shall any investment in reserves exceed 20 years. The Commission shall approve such a plan upon a finding that it is in the public interest after notice and an opportunity for hearing in accordance with the provisions of this chapter.

C) In addition to the items included in the plan as specified in subsection B, the plan may provide the utility with an option to receive the gas or sell the gas at market prices. A utility proposing this option as part of its plan shall propose how any revenue gains from the sale of the gas will be used to reduce the cost of gas to its customers. The Commission shall approve or deny, within 180 days, a natural gas utility's initial application for a natural gas supply infrastructure plan. A plan filed pursuant to this section shall not require the filing of rate case schedules. The Commission shall approve or deny, within 120 days, a natural gas utility's application to amend a previously approved plan. If the Commission denies such a plan or amendment, it shall set forth with specificity the reasons for such denial, and the utility shall have the right to refile, without prejudice, an amended plan or

> amendment within 60 days, and the Commission shall thereafter have 60 days to approve or deny the amended plan or amendment. If the plan is filed as part of a general rate case using the cost of service methodology set forth in § 56-235.2 or a performance-based regulation plan authorized by § 56-235.6, then the Commission shall approve or deny the plan concurrent with or as part of the general rate case decision.
>
> D) No other revenue requirement or ratemaking issues shall be examined in consideration of the initial plan filed pursuant to the provisions of this section.
>
> E) A gas utility with an approved natural gas supply infrastructure plan shall annually file a report of the eligible natural gas supply infrastructure investment made, the eligible natural gas supply infrastructure costs incurred and the amount of such costs recovered, the volume of gas delivered to customers or sold to third parties during the 12-month reporting period, and an analysis of the price of gas delivered to the natural gas utility customers and the market cost of gas during the 12-month period. However, such analysis shall not affect a gas utility's right to recover all eligible natural gas supply infrastructure costs as set forth in subsection B. The report shall also identify the balance of over-recovery or under-recovery of the eligible natural gas supply infrastructure costs at the end of the reporting period and the projected investment to be made, the projected infrastructure costs to be incurred, and the projected costs to be recovered during the next 12-month reporting period.
>
> F) Costs recovered pursuant to this section shall be in addition to all other costs that the natural gas utility is permitted to recover and shall not be considered an offset to other Commission-approved costs of service or revenue requirements.

The Commission has applied the provisions of this statute in analyzing the evidence and arguments presented in this case. Pursuant to Code § 56-609 C, we set forth below with specificity the reasons for denial.

<u>Public Interest</u>

The above statute recognizes, and reflects the public policy of the Commonwealth, that natural gas supply investment plans (as defined therein) may be in the public interest and should be considered for implementation by Virginia's natural gas utilities. None of the participants in this case asserted otherwise.[8] The Commission likewise agrees that the type of plan proposed by WGL could be positive for WGL's customers and be in the public interest; however, in the form that it has been submitted and on this record, the specific Plan proposed in the Application is not in the public interest and is not good for WGL's customers.

Indeed, the above statute recognizes that not all such plans will necessarily be in the public interest. The detailed provisions of these plans can vary widely. As evidenced by the record developed in this proceeding, there can be a myriad of variables associated with such plans, including: the specific natural gas reserves and upstream pipelines and facilities in which the utility is investing (this may include, as defined in § 56-609, equipment required to prepare the natural gas for use, gathering, transmission, and distribution pipelines necessary to deliver the reserves, and above-ground and below-ground storage used in the delivery of gas to existing natural gas transmission pipelines or distribution systems); the capital costs of the investment; depreciation; ongoing operating and maintenance expenses; property, severance and any other taxes or fees; return on investment; the length of the proposed plan; the volumes of natural gas provided thereunder; and associated risks related to the specific provisions of any particular plan.

As a result, although the statute addresses parameters that may be attendant to such plans, the General Assembly has required the Commission to find that each specific plan proposed by a natural gas utility is in the public interest before it may be implemented under the statute. Code § 56-609 requires WGL to "demonstrate that the plan is in the public interest with due consideration to providing a portion of the utility's delivered supply at prices at or below the

[8] For example, Staff witness Johnson acknowledged that such plans could be a good deal for consumers and discussed various parameters that impact risks and, as a result, would impact whether any particular deal is in the public interest. *See, e.g.*, Tr. (10/01/2015) at 75-79.

long-term projections as available and defined in the natural gas utility's filing, or reduction in the utility's overall supply risk, or reduction in the utility's overall portfolio price volatility, or a combination thereof." This section also directs that the "Commission shall approve such a plan upon a finding that it is in the public interest...."

The Commission has given due consideration to the items listed above, as well as other factors that are relevant to our analysis of the public interest as discussed herein. In this instance, based on the record developed in this proceeding, the Commission agrees with Consumer Counsel and Staff that the specific Plan proposed in the Application is not in the public interest.

Under the specifics of the proposed Plan, the potential harm to customers is too great when compared to the potential benefits. The Company admits that, from the moment the Commission approves the Plan as proposed in the Application, WGL's customers would bear *all* of the Plan's risks and WGL (and its shareholders) would bear none of those risks.[9] Under such an unbalanced arrangement, an analysis of potential risks, in evaluating the Plan as a whole, becomes particularly relevant to a finding on public interest.

In this regard, the Company's customers bear the risks associated with production volumes from these wells falling short of WGL's projections. WGL witness Wright acknowledged that his estimates of the natural gas reserves and production volumes are just that – estimates – and there remains a risk that production volumes could fall below the levels needed for customers to reap any savings benefit.[10] Staff witness Uland also presented credible production estimates, which significantly impacted the estimated net present value ("NPV") of

[9] As stated by Consumer Counsel: "The only risk to shareholders identified by Company Witness Garza is the consultant expenses and contract deposit that has been made. Those shareholder 'risks' go away if the Plan is approved by the Commission." Consumer Counsel Brief at 6 (citing Ex. 29 (Garza Rebuttal) at 2, 7. *See also* Tr. (10/01/2015) at 190.

[10] *See, e.g.*, Tr. (10/01/2015) at 171-172, 181-182.

the Plan.[11] Under Mr. Uland's production estimates, the Plan will not save money but, rather, results in a $51 million NPV *cost* to customers.[12] Moreover, if actual production is lower than Mr. Wright's estimates by any more than 11.6%, the Plan results in an NPV *cost* to customers for the delivered cost of gas.[13] Staff also noted that "there is no contingency in the contract that would guarantee the replacement of gas should the wells not produce," that "supply risk is not necessarily reduced," and that WGL's supply under the Plan "may be at higher risk than it otherwise would be as the Company would be relying on gas from 25 wells that are located in close proximity to one another and to additional wells operated for others (and thus susceptible to "interference"), to procure [a substantial portion] of its annual firm sales demand."[14] Under the Plan, these production risks – and the increased costs that could result therefrom – are borne by customers; WGL's shareholders bear none.

The Company's customers also bear the risk if WGL's 20-year price forecast is overstated. The statute does not require the Commission to accept, without review or analysis, any single long-term forecast produced by the Company for purposes of evaluating whether the Plan is in the public interest. No party contested that forecast confidence generally decreases as the forecast period extends, and, in this instance, the 20-year plan requires a 20-year forecast. We find that the evidence demonstrates credible concerns regarding sole reliance on the specific U.S. Department of Energy's Energy Information Administration ("EIA") forecast chosen by the

[11] Ex. 15 (Uland) at 9-11.

[12] Ex. 23 (Carsley) at 16. This calculation uses the Company's price projections.

[13] *Id.* at 15-16.

[14] Staff Brief at 8-9.

Company.[15] Staff also ran a credible price forecast analysis, which resulted in a lower price forecast than WGL's and an NPV *cost* to customers.[16] Combining Staff's price forecast analysis with its production forecast results in a $64 million NPV *cost* to customers. Under the Plan, the risk of overestimating future natural gas prices is entirely on WGL's customers; WGL's shareholders bear none.

The Company's customers also bear the risks associated with certain variable costs. That is, only the commodity cost is fixed over the 20-year life of the Plan. There are numerous variable costs that are not fixed, including operation and maintenance expenses, future regulatory compliance and taxation costs, and changes in WGL's cost of capital.[17]

Code § 56-609 B also states that "[i]n no case shall any investment in reserves exceed 20 years." This provision permits 20-year projects, but it does not mandate that all 20-year projects are in the public interest. Rather, this provision removes the Commission's discretion to find that a project *exceeding* 20 years is in the public interest. In the context of the instant Plan, WGL has not established that its proposed 20-year Plan is in the public interest. The proposed Plan creates too great a risk, when compared to the potential benefits, that customers will be harmed.

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[15] *See, e.g.*, Ex. 23 (Carsley) at 7-8 and 9; Tr. (10/01/2015) at 11-12, 32-33, and 65-66; Ex. 20 (EIA Price Forecast v. Actual Cash Settlements). Staff also asserted that WGL "selected a single EIA forecast of among many that that agency offers," that WGL used that forecast "in a manner not countenanced by the agency that developed it," and the EIA itself has cautioned that the forecast used by WGL "should not be viewed in isolation" and "[r]eaders are encouraged to review alternative cases to gain perspective on how variations in key assumptions can lead to different outlooks for energy markets." Staff's Brief at 8 n.6.

[16] Ex. 23 (Carsley) at 13-14.

[17] *See, e.g.*, Ex. 19 (Johnson), Attachment 1 at 10-12; Tr. (10/01/2015) at 18-21, 40-41, 83. In addition, we need not reach herein the legal question of whether the statute *requires* the Commission to adjust the Company's cost of capital during the life of the Plan. The Commission also notes that the Company offered to treat environmental regulatory compliance costs as a regulatory asset. *See, e.g.*, Tr. 166-67. While the Commission does not address herein whether the Company's offer represents a proper accounting treatment for such costs, we note that such treatment would not lessen the obligation of customers to bear those costs.

Natural Gas Volume Limitations

The statute prohibits the Commission from approving proposed Plans that exceed certain natural gas volumes. Specifically, Code § 56-609 B provides as follows: "No project may provide an annual volume of natural gas that exceeds 12.5% of the natural gas utility's annual firm sales demand, and no combination of projects may provide an annual volume of natural gas that exceeds 25% of the natural gas utility's annual firm sales demand." It is uncontested that the proposed Plan provides an annual volume of natural gas that exceeds 12.5 % of WGL's annual firm sales demand in Virginia.[18]

The Company, however, argues that the 12.5% and 25% Virginia statutory limits above do not apply to WGL's Virginia jurisdiction but, rather, apply to WGL's *total combined* annual firm sales demand for Virginia, Maryland, and the District of Columbia.[19] Consumer Counsel and Staff disagree with WGL's statutory interpretation.[20] The Commission finds that the Virginia statutory limits apply to WGL's Virginia jurisdictional annual firm sales demand.[21]

The Commission has considered WGL's argument that "the statutory provision that relates to the quantity of annual reserves that may be procured pursuant to § 56-609 B is clear and unambiguous" and does not limit such quantities to a utility's Virginia jurisdictional operations.[22] The Commission does not agree that the plain language includes *non*-Virginia

[18] *See, e.g.*, Ex. 33 (Lowe Rebuttal) 3-7; Ex. 11(Armstrong) at 6.

[19] *See, e.g.*, WGL's Legal Memorandum at 3-5.

[20] *See, e.g.*, Staff's Legal Memorandum at 3-6; Consumer Counsel's Legal Memorandum at 2-4.

[21] Moreover, if the statute did not limit the Plan to 12.5% of WGL's Virginia firm sales demand, we find that the amount of Virginia firm sales demand that would be provided by, and under the terms of, this particular Plan is not in the public interest.

[22] WGL's Legal Memorandum at 4.

jurisdictional load. Moreover, WGL's interpretation of the plain language creates a result in which the statute would be internally inconsistent and incapable of operation.[23]

Specifically, there are seven natural gas utilities in Virginia to which the statute applies. Two of those utilities, WGL and Atmos Energy Corporation ("Atmos"), provide natural gas service to jurisdictions outside of Virginia. As a result, if Code § 56-609's reference to a "natural gas utilit[y]" includes non-Virginia jurisdictions, then: (i) the volume limitations for WGL and Atmos would be inconsistent with the limitations on the other five natural gas utilities operating in Virginia; (ii) while a single project for the five Virginia-only utilities would be limited to 12.5% of annual Virginia demand, a single project for WGL could exceed 25% of its Virginia demand (*i.e.*, 12.5% of WGL's total combined demand for Maryland, the District of Columbia, and Virginia reflects over 25% of its Virginia jurisdictional demand); and (iii) based on Atmos' total combined demand from all of the states in which it operates, a single project for Atmos under Code § 56-609 could exceed 100% of its Virginia demand.[24] These results are internally inconsistent and, for Atmos, incapable of operation.

WGL further argues that, in other parts of the Code, "distinctions are made between the use of data on a utility's system basis and data limited to a utility's Virginia jurisdictional operations."[25] This does not alter our conclusion. Code § 56-609 does not include the words "in Virginia" after any of its references to natural gas utilities, yet the context of those other references are logically limited to Virginia-jurisdictional operations. As noted by Staff:

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[23] *See, e.g., Covel v. Town of Vienna*, 280 Va. 151, 158 (2010) ("An absurd result describes situations in which the law would be internally inconsistent or otherwise incapable of operation.") (internal quotes and citations omitted).

[24] *See, e.g.,* Staff's Legal Memorandum at 3-6; Consumer Counsel's Legal Memorandum at 2-4; Ex. 11 (Armstrong) at 6 n.6.

[25] WGL's Legal Memorandum at 4.

> The Assembly likewise failed to insert "in Virginia" anywhere in § 56-609 A 1, which requires the Commission, in calculating the return on investment to be applied to eligible projects to use "the utility's then in effect weighted cost of capital[.]" Nor do the words "in Virginia" appear in § 56-609 A 4, which directs the Commission to apply "the natural gas utility's current depreciation rates for investment in distribution infrastructure" when calculating that expense. Likewise, the words "in Virginia" are not found in § 56-609 A 6, which requires the Commission, in calculating the natural gas utility's carrying costs, to "use the natural gas utility's regulatory capital structure[.]" Under the Company's interpretation of the statute, the Commission would be obligated to consider WGL's capital structure, weighted cost of capital, and depreciation rates established by the Maryland and D.C. Public Service Commissions in establishing appropriate rates to recover the Company's investment in assets intended to provide service only to Virginia customers. This is non-sensical.[26]

Finally, even if the statute is found to be ambiguous (*e.g.*, if "the text can be understood in more than one way ... or lacks clearness or definiteness"),[27] we find that the reference to "natural gas utility" throughout Code § 56-609 means a Virginia-jurisdictional natural gas utility for, among other things, the reasons discussed above for effectuating the legislative goal and avoiding an absurd result.[28]

Accordingly, IT IS ORDERED that the Application is denied and this matter is continued.

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[26] Staff's Legal Memorandum at 4-5. *See also Eberhardt v. Fairfax County Employees Ret. Sys. Bd. of Trs.*, 283 Va. 190, 194-95 (2012) ("In addition, in evaluating a statute this Court has said that consideration of the entire statute ... to place its terms in context to ascertain their plain meaning does not offend the rule because it is our duty to interpret the several parts of a statute as a consistent and harmonious whole so as to effectuate the legislative goal.") (internal quotes and citations omitted).

[27] *Covel v. Town of Vienna*, 280 Va. at 158 (internal quotes and citations omitted).

[28] *See, e.g., Commonwealth v. Leone*, 286 Va. 147, 150 (2013) ("If a statute is subject to more than one interpretation, we must apply the interpretation that will carry out the legislative intent behind the statute.") (internal quotes and citations omitted). In addition, we do not herein reach the legal question, which was addressed in the participants' briefs, of whether Code § 56-609 requires the Commission to adjust WGL's cost of capital (used in calculating the return on investment included in the costs of the Plan) during the 20-year term of the Plan.

AN ATTESTED COPY hereof shall be sent by the Clerk of the Commission to all persons on the official Service List in this matter. The Service List is available from the Clerk of the State Corporation Commission, c/o Document Control Center, 1300 East Main Street, First Floor, Tyler Building, Richmond, Virginia 23219. A copy shall also be sent to the Commission's Office of General Counsel and Divisions of Energy Regulation and Utility Accounting and Finance.

PUBLIC VERSION

CONSTELLATION NEWENERGY-GAS DIVISION, LLC

EXHIBIT SB-5

OF

STEPHEN BENNETT DIRECT TESTIMONY

<u>IS CONFIDENTIAL</u>

IN THE MATTER OF THE APPLICATION OF BLACK HILLS NEBRASKA GAS UTILITY COMPANY, LLC D/B/A BLACK HILLS ENERGY FOR APPROVAL OF ITS GAS HEDGE AGREEMENT WITH BLACK HILLS UTILITY HOLDINGS, INC.

APPLICATION NO. NG-0086