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August 12, 2016

Via Electronic Filing

Public Utility Commission of Oregon
Attn: Filing Center
201 High St. SE, Suite 100
Salem OR 97301

Re: In the Matter of PORTLAND GENERAL ELECTRIC CO.
2017 Annual Power Cost Update Tariff
Docket No. UE 308

Dear Filing Center:

Please find enclosed the redacted version of the Confidential Opening Gas-Hedging Testimony and Exhibits of Bradley G. Mullins on behalf of the Industrial Customers of Northwest Utilities ("ICNU") in the above-referenced docket.

The confidential portions of ICNU's testimony and exhibits are being handled pursuant to the protective order issued in this proceeding and will follow to the Commission via Federal Express

Thank you for your assistance. If you have any questions, please do not hesitate to call.

Sincerely,

/s/ Jesse O. Gorsuch
Jesse O. Gorsuch

Enclosures

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that I have this day served the confidential pages of the **Opening Gas-Hedging Testimony and Exhibits of Bradley G. Mullins** upon the parties shown below by mailing copies via First Class U.S. Mail, postage prepaid, or by hand-delivery.

Dated at Portland, Oregon, this 12th day of August, 2016.

Sincerely,

/s/ Jesse O. Gorsuch
Jesse O. Gorsuch

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BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 308

In the Matter of	)
	)
PORTLAND GENERAL ELECTRIC	)
COMPANY,	)
	)
2017 Annual Power Cost Update Tariff.	)
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	)

CONFIDENTIAL OPENING GAS- HEDGING TESTIMONY

OF BRADLEY G. MULLINS

ON BEHALF OF THE INDUSTRIAL CUSTOMERS OF NORTHWEST UTILITIES

(REDACTED VERSION)

August 12, 2016

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OPENING GAS HEDGING TESTIMONY OF BRADLEY G. MULLINS

EXHIBIT INDEX

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Bradley G. Mullins, and my business address is 333 SW Taylor Street, Suite 400, Portland, Oregon 97204.

Q. ARE YOU THE SAME BRADLEY G. MULLINS WHO PREVIOUSLY FILED TESTIMONY IN THE POWER COST PHASE OF THIS PROCEEDING?

A. Yes. I previously prepared testimony on behalf of the Industrial Customers of Northwest Utilities ("ICNU") regarding the power costs of Portland General Electric Company (the "Company" or "PGE"). A summary of my education and work experience was provided in ICNU/101.

Q. WHAT IS THE PURPOSE OF THIS TESTIMONY?

A. Pursuant to the April 18, 2016 Conference Report issued by Administrative Law Judges Allan J. Arlow and Ruth Harper, this proceeding has been bifurcated into two phases—the first addressing issues related to the AUT and the second addressing the Company's proposal to implement a long-term gas hedging strategy. This testimony specifically addresses issues related the Company's proposal to implement a long-term gas hedging strategy, which would begin with a proposed transaction between the Company and a confidential counterparty, as detailed in the Company's July 22, 2016 Supplemental Testimony.[1/]

II. BACKGROUND AND SUMMARY

Q. PLEASE PROVIDE AN OVERVIEW OF THE COMPANY'S PROPOSAL.

A. As described in its initial filing, the Company proposes that the Commission establish guidelines that would frame the requirements for a long-term gas hedging strategy. These

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[1/] *See* PGE/700, Sims-Tooman/1.

guidelines would effectively constitute pre-approval of the prudence of any transaction the Company enters into that is within the constraints of the guidelines.[2/] Specifically, the Company has proposed the following four guidelines for any long-term gas hedge:

1) Establish that the "Long-Term Projected Cost" must be at or below the comparable "Long-Term Benchmark Price";
2) Establish a maximum gas purchase commitment;
3) Enter into transactions for properties that contain "Proved Reserves" or "Probable Reserves"; and
4) Establish limits within which the unit cost of the long-term gas is incorporated into PGE's annual power cost update.[3/]

For this AUT, the Company has entered into a transaction with a confidential counterparty for a drilling program in the U.S. Rocky Mountain region that is subject to Commission approval before it can be finalized (the "Transaction"). Specifically, the Company, through a newly created affiliate called Portland General Gas Supply Company ("PGGS"), would obtain a non-operating working interest in [redacted] gas wells.[4/] The cost of the 2017 drilling program is estimated to be approximately $[redacted].[5/] The Transaction includes terms that provide the Company with an option, subject to certain restrictions, to expand the drilling program over the subsequent five-year period.[6/] The Company proposes to pass the costs and benefits of the Transaction to customers through a Purchase Gas Agreement with PGGS.[7/] Overall, the

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2/ PGE/200, Sims-Outama/2:5-6.
3/ *Id.* at 3:6-19.
4/ PGE/600, Russell-Tooman/2:3-8.
5/ *Id.* at 3:9-12.
6/ *Id.* at 2:9; PGE/701C, Capital Program Agreement ¶ 4.1.
7/ PGE/100, Tinker-Sims/19:19-20.

Transaction results in an increase of approximately $[redacted] in NPC in 2017 relative to what customers would have paid without a long-term gas hedge,[8/] although the Transaction may have greater cost impacts in future proceedings.

The Company has requested the following approvals: (1) approval of affiliated interest transactions between the Company and PGGS; (2) a waiver of the lower-of-cost-or-market rule between the Company and PGGS; (3) approval of its proposed guidelines for its long-term hedging program; and (4) approval of inclusion of its long-term hedging costs in customer rates.[9/]

Q. PLEASE SUMMARIZE YOUR RECOMMENDATIONS AND CONCLUSIONS WITH RESPECT TO THE TRANSACTION.

A. ICNU has fundamental concerns with a long-term gas hedging program. From a fuel price perspective, my analysis below shows that customers are likely to be worse off than they otherwise would have been absent a long-term gas hedging program. Additionally, by purchasing non-operating working interests in gas wells, the Company would expose customers to risks that customers are not exposed to today – risks such as environmental liabilities, counterparty performance, and others. Meanwhile, the Company would be largely insulated from these risks and would be able to earn a return on its investment by rate-basing a portion of its power costs. If the Company fully executes its proposed long-term hedging program, up to 60 percent of its gas portfolio will be hedged five years out or longer.[10/]

With respect to the specific Transaction at issue, the PGE team leading this effort has done an excellent job communicating with stakeholders, including ICNU, throughout the

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8/ PGE/700, Sims-Tooman/2:10-12.

9/ PGE/100, Tinker-Sims/21:16-22.

10/ ICNU/203 at 5 (The Company's Response to ICNU Data Request 21).

negotiation process, and has negotiated terms that fit well within the constraints of the Company's proposed guidelines. ICNU's concerns, therefore, are not based on the specific Transaction that the Company has presented, but rather, are based upon the nature of its proposed long-term hedging strategy.

Q. IF THE COMPANY'S HEDGING PROGRAM IS TO BE APPROVED, DO YOU HAVE ANY PROPOSED CONDITIONS?

A. Yes. Due to the risks to customers associated with a long-term hedging strategy, as well as the front-loaded nature of the revenue requirement associated with the Transaction, I propose the following conditions if the Commission is to approve the Company's program: (1) any pre-approval of future transactions should be limited to no more than 30% of the Company's gas portfolio, including hedging associated with its mid-term strategy; and (2) the Commission should insulate customers from risks unique to the Company's proposal to acquire non-operating working interests in gas wells, including environmental risk and counterparty risk. The details of these recommendations will be discussed below.

III. THE PROPOSAL IMPOSES ASYMMETRICAL RISK ON CUSTOMERS

Q. THE COMPANY'S FIRST GUIDELINE FOR ITS PROPOSED LONG-TERM HEDGING PROGRAM IS THAT THE LONG-TERM PROJECTED COST IS AT OR BELOW THE LONG-TERM BENCHMARK PRICE. DO YOU HAVE ANY CONCERNS WITH THIS GUIDELINE?

A. Yes. The Company's proposed guideline would deem a transaction cost-effective if the real, levelized cost of the proposed transaction was at or below the real, levelized forecast cost of gas used in the Company's integrated resource plan.[11/] Ultimately, this makes the long-term hedging program a bet on the forward price curve used to justify the transaction. Not only does this impose new risks on customers, but it is likely to be a bad bet. Both data from the

[11/] PGE/200 at 4:7-11.

Company's existing hedging practices and empirically observed risk premiums indicate that the real, levelized forecasted cost of gas prices ultimately are higher than gas prices end up being in reality. This forecast error is exacerbated the longer out in time the forecast is. Thus, even if the cost of a long-term hedge is below the long-term forecast, unless it is well below that forecast, it is likely to cost customers over time.

Q. PLEASE DESCRIBE THE COMPANY'S CURRENT HEDGING POLICIES.

A. These policies were discussed in Docket No. UE 228. My understanding is that the Company currently hedges 100% of its natural gas requirements using a layering approach.[12/] Thirty percent of these hedges occur over the three- to five-year timeframe.[13/] The Company calls this its "mid-term strategy" or "MTS". This strategy is also discussed briefly in Section 6 of the Company's Energy Risk Management Policies and Procedures.[14/]

Q. WHY ARE YOU CONCERNED WITH THE COMPANY'S CURRENT HEDGING POLICIES?

A. Confidential Table 1, below, details the amount of gas hedging losses that the Company has included in its AUT filings for the past three Annual Power Cost Update ("APCU") filings. The values were derived from the Company's final MONET runs from the 2015 and 2016 AUTs (Docket Nos. UE 286 and UE 294).

12/ Confidential ICNU/203 at 3 (the Company's Response to ICNU Data Request 13, Confidential Attachment A.)

13/ PGE/100, Tinker-Sims/8 (Figure 1).

14/ Confidential ICNU/203 at 3 (the Company's Response to ICNU Data Request 13, Confidential Attachment A.)

CONFIDENTIAL TABLE 1
Historical Amount of Financial Hedging Losses / (Gains)
in APCU Filings 2015 – 2017 ($000)

	2015	2016	2017
Gas Swap Losses	[redacted]	[redacted]	[redacted]
Electric Swap losses	[redacted]	[redacted]	[redacted]
Total	[redacted]	[redacted]	[redacted]

Each year the Company passes substantial amounts of financial hedging losses onto ratepayers through its APCU filing. Yet rarely, if ever, do ratepayers recognize gains as a result of these hedging transactions in rates. In this proceeding, for example, the Company proposes to pass approximately $[redacted] in financial gas hedging costs and $[redacted] in electric hedging losses onto ratepayers, amounts which are in addition to the cost associated with the Company's proposed long-term gas hedge. My concern is that these hedging losses may be systematic, a byproduct of a bias, risk premium, or some other factor present in forward gas markets.

Q. WHY WOULD THE PRESENCE OF A RISK PREMIUM IN FORWARD GAS MARKETS INDICATE THAT RATEPAYERS ARE BETTER OFF HEDGING LESS?

A. To the extent that there is a risk premium in forward gas markets, it means that ratepayers will statistically pay more as a result of the Company's acquisition of forward hedges than they would if the Company were to purchase in near-term markets. While conducting hedging using dollar-cost averaging can result in smoothing of cost changes over time, this smoothing is, in my opinion, best justified to the extent it results in no additional cost to ratepayers over time—that is, to the extent that there is no risk premium present in forward markets.

Q. DO YOU BELIEVE THAT HEDGING RESULTS IN SYSTEMATIC COSTS TO CUSTOMERS?

A. Recent data certainly seems to indicate so. Confidential Figure 1, below, details an empirical analysis of observed risk premiums in forward natural gas markets over the period 2010 to the present, based on the Company's various forward price curves prepared over the period.

CONFIDENTIAL FIGURE 1

Empirically Observed Risk Premiums, Rockies Gas, 2010 – 2016

[redacted]

Q. PLEASE DESCRIBE THE DATA PRESENTED IN CONFIDENTIAL FIGURE 1.

A. Confidential Figure 1 is a plot of the percentage forecast error associated with forward prices included in forward price curves issued by the Company over the period 2010 through early 2016. Each dot in the figure represents the percentage difference between a price that was forecast in a forward curve and the ultimate spot price for the given prompt month. To the extent that the error is positive, it means that the price in the forward curve exceeded the ultimate spot price. To the extent that the error is negative, it means that the price in the forward curve was less than the ultimate spot price. Along the x-axis, the set of forecast errors were separated by the number of months before the prompt month for which the forward price was calculated. Thus, a forecast error further to the right indicates the forecast error associated with a price that was forecast further in advance of the prompt month. Similarly, a forecast error on the left side of the x-axis represents a price that was forecast nearer to the prompt month. Overlaid on the figure is the median forecast error based on the number of months in advance of the prompt month that the forward prices were calculated, as well as the interquartile range of the forecast errors.

Q. HOW CAN THE DATA PRESENTED IN CONFIDENTIAL FIGURE 1 BE USED TO DETERMINE WHETHER THERE IS A RISK PREMIUM IN FORWARD GAS PRICES?

A. If there is no risk premium present in these forward curves, it would be expected that the forward prices are an unbiased expectation of future spot prices. That is, it should be expected that forward prices exceed the ultimate spot price 50% of the time and are less than the spot price 50% of the time. Stated differently, if there is no risk premium, the median forward curve forecast error should be zero. If, however, the median forecast error exceeds zero, that is an indication of a risk premium.

Q. WHAT DOES THE DATA IN CONFIDENTIAL FIGURE 1 DEMONSTRATE?

A. The empirical analysis in Confidential Figure 1 indicates that there have been risk premiums embedded in forward markets for natural gas over the period 2010 to 2016 and that those risk premiums have been substantial. For a transaction executed between one and two years in advance of the prompt month, the expected risk premium value was approximately 30%. This means that each time the Company purchases a financial gas swap between one and two years in advance of the prompt month, ratepayers should statistically expect to ultimately pay an amount that is 30% greater than the actual spot price of natural gas. This is a considerable premium, particularly when considered in relation to any potential value that may be gained from the price certainty afforded through the Company's short- and mid-term hedging strategies. In my view, this data calls into question the prudence of the Company's strategy for hedging 100% of its natural gas requirements. As detailed in Exhibit ICNU/201, others share the view that it is inappropriate for a utility to hedge 100% of its gas requirements, including Senior Policy Staff of the Washington Utilities and Transportation Commission ("WUTC"), who were quoted as stating that hedging 20% to 30% of fuel needs "should be adequate," given that gas prices are expected to remain low for years to come.

Q. WHAT DOES CONFIDENTIAL FIGURE 1 INDICATE WITH RESPECT TO LONG-TERM HEDGING?

A. Another important feature of Figure 1 is that there is a positive relationship between the observed risk premiums and how far ahead of the prompt month the forward price is calculated. This reaffirms the intuitive notion that if the utility wants to lock in prices for a longer period, it is generally going to have to pay more to do so. It also reaffirms ICNU's objection to a long-term hedging policy, as such a policy should be expected to cost ratepayers greatly in the long run.

Q. DO YOU HAVE OTHER CONCERNS WITH THE COMPANY'S STRATEGY?

A. Yes. The Company's proposal imposes other significant risks on customers by using customer money to enter the unregulated gas production business. This is a business that is not always kind to its participants and has seen a number of bankruptcies in recent years. These risks include production risk, environmental risk, counterparty risk, and gas price risk. While customers would assume all of these additional risks, the Company, under its proposal, would be largely insulated from them, and will get to earn a return on its investment.

Q. PLEASE EXPLAIN HOW A LONG-TERM HEDGE IMPOSES GAS PRICE RISK ON CUSTOMERS.

A. As noted above, a long-term hedging program is ultimately a bet on the forward price curve used to justify the transaction. If actual market prices end up being higher than the price curve, ratepayers benefit from the transaction. If actual market prices end up being lower, ratepayers are harmed by the transaction. This is the nature of a long-term financial hedge and it brings with it a certain financial risk that ratepayers are not exposed to today. Consequently, while the Company's program does provide a modest level of gas price stability, this is not the same as saying it reduces customer risk. Rather, the Company's proposed program merely substitutes one risk for another. Customers are exposed to long-term gas price fluctuations today, whereas under the Company's proposal, this would be mitigated somewhat in exchange for customers bearing the additional risk that the cost of the hedge exceeds long-term gas prices.

Q. IS A LONG-TERM HEDGE LESS RISKY AS A RESULT OF LOW PRICES FOR NATURAL GAS?

A. No. The forward curves used to justify the long-term hedge include the assumption that gas prices will increase over time. Thus, if gas prices do not increase as expected, and remain at the levels they are today, then a long-term hedge will end up costing ratepayers money.

Q. DOES THE COMPANY'S PROPOSED LONG-TERM HEDGING POLICY ALIGN WITH THE RISK PREFERENCES OF LARGE CUSTOMERS?

A. No. While utility customers certainly pay different prices depending upon the utility from which they take service, all customers are generally exposed to the same short- and long-term fluctuations in gas prices. That is, whether a utility customer is served by PacifiCorp, Portland General Electric Company, Pacific Gas and Electric Company or some other similar utility, it will be similarly exposed to the long-term changes that occur in response to changing market conditions for natural gas.

As a result of this dynamic, from the perspective of a large customer, it is generally preferable not to conduct long-term hedging and to allow electric services rates to fluctuate in the long-term in response to changing market conditions for gas and electricity. This has to do with the economics of the fact that many large customers are competing in regional and global markets against peers which are served by other utilities.

The decision to lock in forward rates today through the execution of a long-term hedge impacts how competitive a large customer will be relative to its peers served by other utilities. To the extent that a large customer of PGE pays electric service rates that are greater than those paid by a competitor, the PGE customer is provided with a competitive disadvantage. Similarly, to the extent that a large customer of PGE pays electric service rates that are less than those paid by a competitor, the PGE customer is provided a competitive advantage. Thus, by locking in a fixed price today through the execution of a long-term hedge, the competitive position of the large customer of PGE will become either more, or less, competitive relative to its current competitive position amongst its peers, depending on the future behavior of market prices and the ultimate outcome of the hedging transaction.

The risk of becoming either more, or less, competitive, however, is not a risk that large customers prefer to take on in their power rates. Rather, it is generally a less risky strategy for large customers to allow rates to fluctuate in the long-term in response to market conditions, as a large customer will have greater certainty that it will be neither harmed, nor benefited, relative to its existing competitive position. Certainly, if a large customer were to conclude that a strategy of locking in a long-term forward gas price today would be beneficial, it could, itself, enter into a transaction similar to that proposed by the Company. Large customers typically do not engage in such transactions because these transactions fall outside of the scope of their expertise, just as such a transaction falls outside the scope of the Company's.

Q. PLEASE DISCUSS THE OTHER RISKS CUSTOMERS WOULD ASSUME THROUGH THE COMPANY'S LONG-TERM HEDGING POLICY.

A. Customers face risk associated with the actual production of the gas wells. Ultimately, the cost per mmbtu of gas from Company-owned wells depends on how productive they are. The Company's proposed guidelines mitigate this risk somewhat by restricting the wells to "proved" or "probable" reserves and by imposing a 10% production band on the costs that are included in rates. However, these guidelines do not eliminate production risk altogether, whereas customers do not bear this risk today. In addition, there is a concern that the variations in the production curve could make this production band punitive to ratepayers. For example, if the gas reservoir is depleted more quickly than expected, ratepayers may end up losing a great deal of production from the reservoir due to the band. While ratepayers would still have to pay for their entire share of the reserves, the amount of production received by ratepayers over the life of the well would not correspond to the amount that ratepayers paid for. The Company has negotiated a provision in the Transaction that [redacted], which could mitigate this concern.[15] However, it is not clear how this provision will operate in practice.

There are also environmental risks associated with gas production that could impose significant costs on customers and, as a joint owner of these wells, the Company, and ultimately its customers, are exposed to risks associated with the other owner, and operator, not adhering to its contractual responsibilities or becoming financially insolvent. As with production risk, the Company has proposed certain criteria, such as drilling in remote areas and contracting with creditworthy counterparties, that mitigate these risks.[16] Again, however, they do not eliminate these risks altogether, whereas customers do not face these risks today. Moreover, while these risks may be acceptable with respect to the Transaction the Company has entered into for 2017, they increase with an increase in the size of the Company's hedging program, which is ultimately the Company's goal.

There are also other commodity risks associated with oil and other non-gas liquids that are extracted as a part of the production of natural gas. These non-gas liquids could constitute a material portion of the production from the wells under consideration.[17] Because the Company's forecast includes a revenue credit that it will recognize as a result of these non-gas liquids, the Transaction would expose ratepayers to markets to which they are not exposed

[15] PGE/701C, Capital Program Agreement ¶ 5.4.
[16] PGE/300, Russel-Tooman/3:8-16, 7:21-11:16.
[17] *See id.* at 5:14-16; PGE/304.

today. To the extent the Company's assumptions with respect to these revenues do not conform to the reality of future prices, it could result in material, unexpected costs to ratepayers.

While ICNU appreciates the substantial effort undertaken by the Company to mitigate the risks associated with the Transaction, ICNU simply does not consider the remaining risks to be worth the modest level of rate stability the Company is proposing, which, again, could itself end up costing customers more than they otherwise would have paid and is contrary to the risk preferences of large customers.

Q. HAS NATIONAL ASSOCIATION OF REGULATORY UTILITY COMMISSIONERS ("NARUC") RECENTLY CONDUCTED A STUDY ON THIS MATTER?

A. Yes. In February of 2016, the National Regulatory Research Institute ("NRRI") released a study on "Vertical Arrangements for Natural Gas Procurement by Utilities." A copy of that study is provided in Exhibit No. ICNU/202. The author, Mr. Ken Costello, Principal Researcher, Natural Gas Research and Policy, at NRRI, came to the conclusion that, "[a]fter reviewing different vertical-arrangement plans [including non-operating working interests in gas wells], it is evident that customer risk is excessive relative to utility or holding company risk."[18/] I generally agree with Mr. Costello's assessment, as well as a number of the arguments that he has presented in the document. Mr. Costello finds that customers face a number of the same risks associated with a long-term gas hedge I have already discussed, while at the same time concluding that "proposals for ownership of gas reserves seem to pose little risk for utilities but allow them to

[18/] ICNU/201, Mullins/7

profit from the rate-basing of the investment."[19/] He notes that "Moody's Investors Service describes utility investments in gas reserves as a 'new rate base strategy.'"[20/]

Q. IF THE COMMISSION IS TO APPROVE THE COMPANY'S LONG-TERM HEDGING PROGRAMS, DO YOU HAVE ANY RECOMMENDATIONS TO REDUCE RISK TO CUSTOMERS?

A. Yes. Given the asymmetrical benefits and burdens borne by customers and the Company under the Company's long-term hedging program as proposed, the Commission should limit the risks that customers should bear. Specifically, the Commission should require the Company to hold customers harmless for any costs associated with unanticipated environmental liabilities (that is, those other than expected, end-of-life, remediation costs) and liabilities associated with counterparty insolvency or nonperformance under the joint operating agreement and the capital program agreement. Additionally, given the costs associated with the Company's hedging programs, the Commission should not pre-approve any hedging contract that results in the Company hedging more than 30% of its gas requirements more than one year in advance. This would be inclusive of the Company's mid-term strategy.

IV. RATEMAKING CONCERNS

Q. WHAT RATEMAKING CONCERNS DOES A TRANSACTION OF THIS NATURE PRESENT?

A. Because the Company is proposing to rate base the Transaction assets, the revenue requirement associated with the Transaction is front-loaded, relative to the timing of when the gas will be produced and when the benefits will be recognized by ratepayers. This presents a number of ratemaking problems, including the fact that, to the extent the Transaction ends up working against ratepayers' interests, the financial damage will have already been done. Ratepayers

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19/ *Id.* at 53.
20/ *Id.*

will not ultimately know whether the transaction proves to be beneficial until years from now. Yet, by that time ratepayers will have already borne the bulk of the cost associated with the Transaction. It is always concerning to ratepayers to be asked to pay large amounts up front for benefits that may not be achieved for a large number of years. Such a scenario also creates intergenerational inequity.

Q. WHY DOES THE TRANSACTION CREATE INTERGENERATIONAL INEQUITY?

A. The reason why the transaction costs are front-loaded, and why the transaction creates intergenerational inequity, primarily has to do with the *return on* component of the Transaction revenue requirement. If the Company were to account for this investment outside of its utility operations, the returns on its investment would occur gradually over time, as gas is produced from the wells and sold into the market. Under the revenue requirement formula used by public utilities, however, the Company is provided a fixed return on its investment each year based on the amount of net plant reflected on its books. Because the investment will deplete over time, the return component is the largest at the beginning of the investment's useful life, and gradually declines as the investment in the gas reservoir depletes. In other words, today's customers will pay more per unit of gas to achieve lower cost gas for tomorrow's customers.

Q. DO OTHER EXPENSES ASSOCIATED WITH THE TRANSACTION CONTRIBUTE TO INTERGENERATIONAL INEQUITY?

A. Generally, no. Because depletion accounting is used, the *return of* the Company's investment generally corresponds to the timing of when gas is produced. Unlike depreciation accounting, in which the cost of an asset is spread over time, the cost of an asset under depletion accounting is expensed as the resources underlying the asset are extracted. Thus, the *return of* component of the Transaction revenue requirement contributes less to the concerns of front-loading and intergenerational inequity. In fact, the very reason why depletion accounting is used is to properly align the timing of cost recovery expense with the timing of when the benefits associated with the investment, in the form of gas withdrawals, are recognized. This matching principle inherent in depletion accounting is, therefore, explicitly designed to avoid the mismatching between costs and benefits that occur in cases of intergenerational inequity.

Q. ARE THESE INTERGENERATIONAL INEQUITY CONCERNS AN ADDITIONAL REASON WHY THE PROGRAM PROPOSED BY THE COMPANY IS PROBLEMATIC?

A. Yes. Absent some sort of regulatory mechanism that requires the Company to shape the *return on* its investment in a manner that corresponds to the timing of when the natural gas is extracted from the wells, as it has done with the *return of* component, the proposed program will require customers today to pay more for the benefit of customers in the future. When taken in the context of a drilling program, where the Company is annually acquiring new wells, these concerns are compounded. Each year, when new wells are added, ratepayers will be required to pay more, yet by the time the benefits are to be recognized, those benefits will be offset by the increased cost associated with new wells. Thus, when evaluated in the context of a program, the potential benefits associated with ongoing transactions could be illusory and may never materialize in rates.

V. SUMMARY

Q. PLEASE SUMMARIZE YOUR RECOMMENDATIONS.

A. Given the historical results and the risk premium embedded in gas price forecasts, as well as the incremental risks customers would be assuming, a long-term hedging program is not in ratepayers' best interest. Consequently, I recommend that the Commission deny the Company's request for approval of its proposed guidelines covering its long-term gas hedging program. I also believe that parties should undertake a more thorough examination of the

Company's mid-term strategy in the next AUT, as the presence of a risk premium in forward gas markets indicates that the Company's existing policies are imposing systematic costs on ratepayers.

If, however, the Commission is to approve a long-term hedging program for the Company, then I recommend the following:

1) Customers should be insulated from incremental risks associated with the Company's investment in gas wells, including unanticipated environmental liabilities and the non-performance and/or insolvency of the joint owner and operator; and

2) A limitation on any pre-approval of a hedging program longer than one year to 30% of the Company's gas portfolio, including its existing mid-term strategy.

Q. DOES THIS CONCLUDE YOUR OPENING TESTIMONY?

A. Yes.

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 308

In the Matter of	)
	)
PORTLAND GENERAL ELECTRIC	)
COMPANY,	)
	)
2017 Annual Power Cost Update Tariff.	)
	)

EXHIBIT ICNU/201

U.S. UTILITIES' NATURAL-GAS HEDGES TURN SOUR

August 12, 2016

ICNU/201
Mullins/1

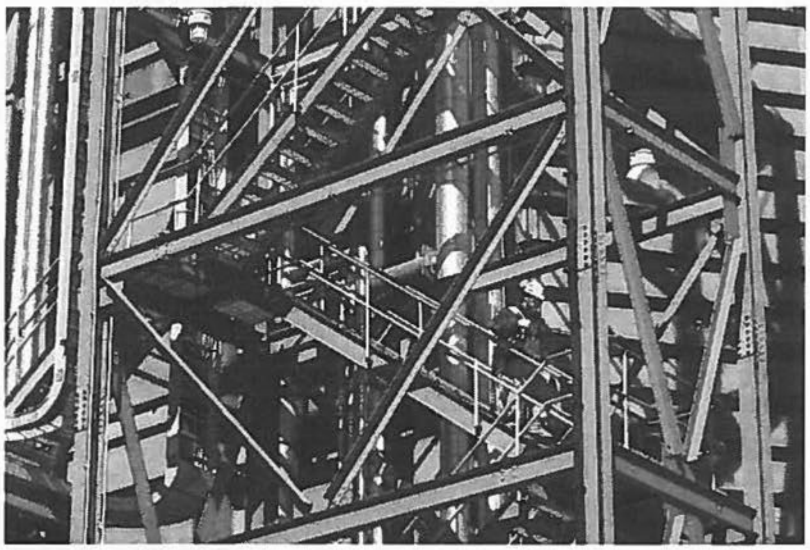
THE WALL STREET JOURNAL.

http://www.wsj.com/articles/u-s-utilities-natural-gas-hedges-turn-sour-1459726648

BUSINESS

U.S. Utilities' Natural-Gas Hedges Turn Sour

Some states have taken action to prod electricity suppliers to rethink hedging



Experts don't know how exactly much money utilities have lost nationwide on natural-gas hedges. *PHOTO: WILL VRAGOVIC/TAMPA BAY TIMES/ZUMA PRESS*

By **REBECCA SMITH**

April 3, 2016 7:37 p.m. ET

Natural-gas prices have plunged 74% in the past 10 years, but some U.S. utilities haven't reaped the full benefit because of bad bets they made to hedge the cost of the fuel.

Utilities that distribute natural gas or burn it to make electricity often enter into hedging contracts as a form of insurance to protect themselves and their customers against wild variations in the fuel's price.

The derivatives contracts don't represent actual fuel deliveries. Rather, if gas prices go up, utilities make profits on the contracts that help offset their higher fuel costs. If gas prices go down, they lose money on the contracts but still benefit by paying less for their fuel.

But in Florida, four utilities including the state's largest, Florida Power & Light Co., suffered net losses of $6 billion on their program from 2002 to 2015 because their natural-gas hedges wound up being considerably more expensive than eventual market prices, a cost that was passed along to their customers.

Experts don't know how exactly much money utilities have lost nationwide on natural-gas hedges. But they say the sum is considerable if Florida is an indicator, because its approach was fairly typical. Utilities often hedge as much as half of their natural-gas purchases. Regulators in states including Louisiana, Oregon and Washington are now examining their utilities' programs.

Ken Costello, an economist at the nonprofit National Regulatory Research Institute, which advises utility commissions, said that while small hedging losses are normal, "there's something wrong if you have losses as big as what Florida experienced."

One problem experts have identified: utilities often have "lock and leave" contracts that aren't informed by market risks or loss tolerances, said Michael Gettings, principal consultant at RiskCentrix LLC in South Carolina. He said such hedging programs are simpler to understand and administer, and have been the standard for utilities for a long time.

Another problem, he said, is that utilities are guided by fear. Following Hurricane Katrina in 2005, for example, many utilities responded to a sharp rise in gas prices by increasing hedging.

"Naturally, it was too late by then," said Mr. Gettings. "They got caught just as prices started to collapse."

Natural gas has experienced four major price spikes since 2000. In June 2008, for example, gas sold for $12.69 per million British Thermal Units. By June 2012, the same amount of gas sold for $2.46.

In February, the average monthly price for Henry Hub gas was $1.99 per million BTUs, according to the U.S. Energy Information Administration, the benchmark's lowest February level since 1999.

In Florida, utility hedging saved consumers about $1 billion from 2002 through 2005 but produced net losses in eight of the next 10 years. In 2009 alone, hedging cost Florida utilities and their customers $2.46 billion, coinciding with the global recession and a steep drop in natural-gas prices, according to state statistics.

Florida Power & Light, a unit of NextEra Energy Inc., accounted for about $4 billion of the $6 billion in the state's net losses. The utility declined to comment.

Over the objections of consumer advocates and big energy consumers, Florida regulators in December decided to let four electric utilities—FPL, Duke Energy Florida, Gulf Power Co. and Tampa Electric Co.—continue to hedge fuel costs.

"We think it would have been better to have discontinued hedging for now," said J.R. Kelly, head of the Florida Office of Public Counsel, the state-funded consumer advocate in utility cases. "It's costing ratepayers too much money."

A spokesman for Gulf Power, the Florida unit of Southern Co. of Atlanta, said his company's net hedging loss of $178 million over 14 years, while unfortunate, was equivalent to less than 3% of its total fuel bill.

Some states have already taken action to prod utilities to rethink hedging. In Washington, where local gas utilities racked up net losses of $1.15 billion on hedging contracts from 2002 to 2012, state regulators have encouraged utilities to figure out a better approach.

With gas prices expected to remain low for years to come, hedging 20% to 30% of fuel needs "should be adequate," said Danny Kermode, senior energy policy adviser for the Washington Utilities and Transportation Commission.

Puget Sound Energy in Bellevue, Wash., saved customers $19 million by hedging gas prices from 2002 to 2005, but sustained net losses of $832 million from 2005 to 2015. It is now working with regulators to design a better strategy that could involve more sophisticated hedging techniques.

"It's a call to arms," said David Mills, the utility's vice president of energy operations.

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VERTICLE ARRANGEMENTS FOR NATURAL GAS PROCUREMENT BY UTILITIES: RATIONALES AND REGULATORY CONSIDERATIONS

August 12, 2016

Vertical Arrangements for Natural Gas Procurement by Utilities: Rationales and Regulatory Considerations

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National Regulatory Research Institute

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Executive Summary

Recent interest in long-term hedging

Both electric and gas utilities purchase large amounts of natural gas as part of their business operations. Prior to the 1980s, a feature of the natural gas industry was contracts of long durations, often over 20 years at fixed prices, for both producer-pipeline transactions and pipeline-gas utility transactions.

Starting around 1985, trading arrangements within the natural gas industry became dramatically more short-term and flexible, in both price and terms and conditions, compared to prior periods. This trend occurred throughout the sector, from gas procurement, gas storage, and retail transactions to capacity contracting for pipeline services. It was a result of a more open and restructured natural gas market, among other things. This market includes buyers and sellers consummating trades with minimal transaction costs. Other developments favoring shorter-term contracts since the mid-1980s include a highly developed financial market for gas hedging and the evolution of short-term electricity markets. In fact, a major motivator of the restructuring of the U.S. natural-gas industry was the high social costs from rigid multi-year contractual arrangements as the industry transitioned to a more liberalized structure. Overall, competitive pressures have made long-term commitments a more expensive proposition for utilities as well as other market participants by increasing risk.

Over the past few years, utilities and gas producers have given increased attention to long-term commercial commitments under a vertical arrangement. Utilities have publicly stated that these commitments complement their current hedging initiatives that mostly today are short term in nature, one to two years.

This interest in long-term transactions hinges on the U.S. gas market having ample supplies over the next several decades, resulting in more stable and predictable prices than seen over the first half of this century. Other factors include low natural gas prices, gas operator cash-flow problems, and a buyer's market. Evolving conditions in the natural gas market have made long-term commitments more palatable and potentially mutually beneficial for both gas operators and utilities.

Proposals for vertical arrangements

This paper focuses on utility long-term commitment in the form of utility ownership of gas reserves (UOGR) or a joint venture with an affiliate exploration and production (E&P) company. Under the first arrangement, a utility would acquire a non-operating interest in gas reserves; the utility becomes a partner with the operating entity. The utility typically pays upfront capital expenditures to fund reserves development and typically a portion of the operating costs. In return, the utility acquires an interest in gas reserves located in specific gas fields. The length of an agreement ranges from five years to multi-decade.

All of the utilities proposing UOGR and joint venture arrangements calculate expected gas cost savings for their customers based on information available at the time – for example, a comparison of gas production costs with market price forecasts – in addition to long-term hedging/price stability benefits and a more secured gas supply. Common features of vertical arrangements for gas procurement include: (1) Cost of service pricing of gas, (2) expected gas-cost savings and stabilized prices to utility customers, (3) for UOGR, rate basing of gas reserves, and (4) imbalanced risk allocation to utility customers.

In their proposals for joint ventures, utilities' forecasts of gas prices 10-40 years out are highly speculative, illogical, and practically meaningless for making decisions. Justification for vertical arrangements must therefore derive from other than forecasted gas savings over time to utility customers. One possible benefit, and one that seems most plausible, if not tenable, is price stability or hedging on a long-term basis. Utilities have different options for hedging. Whether UOGR or another vertical arrangement is a preferred approach to purchasing natural gas from independent entities in the wholesale gas market requires thorough review driven by facts and utility-specific conditions.

Economic theory and commercial structures

Transaction cost economics (TCE) predicts the market conditions under which vertical integration is a preferred institutional arrangement over long-term contracting and spot market transactions. When asset specificity, sunk costs, and a high degree of complexity (e.g., the buyer requires a product to have exact specifications of a high technical nature) characterize a trade, vertical integration can be the most efficient alternative. As the contractual process becomes highly complex, for example, a firm might rationally decide to supply a required input internally rather than purchasing it in the marketplace to avoid the high transaction costs associated with contracting.

The benefits from vertical integration to customers, as specified in the economics literature and realized in actual experiences just seem doubtful for gas procurement by utilities. Vertical integration by electric utilities with coal mines, for example, is consistent with TCE because of asset specificity that makes contracting with an independent entity highly costly. Its rationale for gas procurement seems dubious.

Firms should be less vertically integrated as the cost of using the marketplace to purchase a good or service decreases. Overall, each commercial structure has its strengths and weaknesses. Buying all gas on the spot market, for example, can lead to volatile prices for utilities and their customers. The question for regulators is whether UOGR or utility purchase of gas from an E&P affiliate is compatible with conditions conducive to vertical integration.

The uncertainty of long-term hedging benefits

Utilities proposing vertical arrangements are implicitly assigning a high value to long-term hedging. This value may not reflect customers' perception of benefits. The large hedging losses experienced by utilities in recent years, if anything, suggest a cutback on hedging, rather than expanding hedging on a long-term basis.

In evaluating proposals for vertical arrangements, regulators should have some understanding of the value that utility customers place on stable prices. Hedging is not a costless activity, so the utility should provide evidence, other than conjecture, that customers are willing to pay something for more stable prices over the long term. The vertical arrangements discussed in this paper are all complex, involving substantial utility costs in negotiating, executing, and enforcing and monitoring. Regulators should determine as best they can that these costs are justifiable from the perspective of utility customers.

Perhaps the most fundamental question comes down to how long-term commitments under a vertical arrangement fit within a utility's gas-procurement portfolio. Gas procurement is a multi-objective endeavor where the utility tries to balance reasonable cost, price stability and secured gas supplies. For example, a balanced portfolio of gas supplies might combine different commercial transactions, including long-term and short-term contracts. Most gas and electric utilities apply a portfolio approach to gas procurement, which involves purchasing gas under different durations and other terms and conditions. A motivator for a portfolio approach is the hedging of natural gas prices to customers. Whether a vertical arrangement is compatible with an optimal, balanced gas-procurement strategy requires the attention of regulators in evaluating utility proposals.

The hazards of vertical arrangements

Vertical arrangements raise a number of questions for state public utility regulators. One argument in support of utility ownership is that it would provide utilities with a secured supply of natural gas at stable prices over several years. Although this outcome would be a positive development, regulators have to ask whether other commercial arrangements would be preferred. Some of the utility ownership arrangements, either in place or being proposed, would enable utilities to rate base their gas-reserves assets. Their structure almost always involves little risk to utilities relative to the risk borne by their customers. The benefits to customers from long-term gas cost savings and hedging (i.e., how much customers are willing to pay for more stable prices) come across as highly speculative and devoid of accurate quantification.

Another issue touches on regulatory oversight in which utility-ownership of gas reserves or a joint venture arrangement involves a utility and an affiliate. One major distinction between market transactions and vertical integration is the self-dealing aspect of the latter that can pose tricky problems for regulators, necessitating their oversight and other vigilant actions. A regulator would have to monitor this relationship, for example, to ensure utility customers are not overpaying for natural gas purchased by the utility from its affiliate. The regulator might also need to establish codes-of-conduct rules that explicitly prohibit self-dealing abuses by restricting certain actions. Ring fencing or structural separation would help to avoid cost shifting from the unregulated affiliate to the regulated utility, but not necessarily eliminate it.

To protect its interest, utilities need to be vigilant in monitoring their gas operator partner. Under UOGR, utilities have to make important decisions about choosing a partner and gas basins or wells, and the pricing of gas reserves. Effective utility management in contracting or non-operating ownership includes evaluating and selecting a supplier or partner, and negotiating, executing and administrating contractual agreements. The gas operator may lack strong incentives for cost efficiency, especially with a cost-plus pricing scheme and asymmetric information favoring the gas operator. Incomplete contract provisions can also lead to opportunism or "bad behavior" by the gas operator inimical to utility interests.

Dubious customer benefits

For various reasons, this paper is skeptical about vertical arrangements in benefiting utility customers. It raises the question of what economic gains accrue to utility customers from long-term hedging. We have seen large losses in recent years from short-term hedging by both electric and gas utilities. Multi-decade hedging would seem to pose yet higher risk to utility customers. These risks translate into inflated utility bills for customers. It seems ironic that the major apparent reason for vertical arrangements is to reduce upside price risk to utility customers but, in the process, utilities are asking customers to take on new risks. Although an empirical question, it is conceivable that utility customers could face higher risk from a vertical arrangement involving UOGR or a utility affiliate than from the absence of long-term hedging. A review of the vertical arrangement plans suggests that customers could very well bear higher risk from an action that purports to protect those same customers from risk.

From the perspective of utility customers, vertical integration seems to be a high-risk strategy for hedging. Under most proposals and actual plans, utility customers would shoulder much more risks than utility shareholders or holding companies. Vertical arrangements create several risks. They relate to: (1) gas-production operating cost, (2) level of gas reserves and production (dry holes), (3) liability and incomplete contractual agreement (leaving room for opportunism or, more generally, bad behavior, (4) counterparty risk and (5) for utilities, regulatory-induced risks from less-than-full commitment, regulators knowing little about the upstream side of the gas business and having to evaluate complex contract provisions.

After reviewing different vertical-arrangement plans, it is evident that customer risk is excessive relative to utility or holding company risk. Customer risk comes largely from a low market price, and unanticipated, unfavorable events in gas operation or production from reserves. Commissions entertaining UOGR and other vertical arrangements, or long-term hedging in general, should consider balancing the risks between utility shareholders and customers. The main objective would be to protect utility customers from inaccurate forecasts, which are likely given the long-term nature of the vertical arrangements.

More definitive benefits to utilities and their affiliates

Benefits to utilities and affiliates from vertical arrangements are much more certain. One benefit is higher utility earnings from the rate basing of gas-reserves assets. A utility affiliate could also realize higher profits from selling to the utility instead of the open market. Thus, on the surface expected benefits are larger and more certain for utilities and their affiliates than their customers. Liquid wholesale gas markets (minimizing gas supply risk) plus highly speculative forecasts of long-term gas prices dramatically weaken the argument for UOGR and affiliate transactions. In fact, in one sense the vertical arrangements proposed by utilities resemble more of a speculative than hedging activity. The utilities are betting that future natural gas prices will increase based on highly imperfect information, and then structure a long-term plan designed to achieve gas-cost savings. In sum, utilities should have a strong burden of proof showing that vertical arrangements are good for their customers in the long term.

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Vertical Arrangements for Natural Gas Procurement by Utilities

Rationales and Regulatory Considerations

I. Recent Interest in Going Long Term

A. Reversal of past trends

Prior to the 1980s, the natural gas industry featured bilateral contracts of long durations (e.g., over 20 years) at fixed prices, for both producer-pipeline transactions and pipe line-gas utility transactions. Starting around 1985, trading within the natural gas industry rapidly shifted toward more short-term and flexible arrangements in both price and terms and conditions, compared to prior periods.[1] This trend occurred throughout the sector, from gas procurement, gas storage, and retail transactions to capacity contracting for pipeline services.[2]

Within the past five years, as a reversal to prior actions, both electric and gas utilities and gas producers have given increased attention to long-term commercial arrangements for natural gas transactions.[3] Utilities have publicly stated that these commitments complement their current hedging initiatives that today are mostly short term in nature, one to two years.

Although natural gas prices have become more stable, compared to the first half of this century, the common perception is that they are still inherently volatile. Other factors favoring long-term commitments include current low natural gas prices that are expected to remain low for the next few years, gas operator cash-flow problems, and, as a result, a buyer's market. Overall, evolving conditions in the natural gas market have made long-term commitments more likely to be mutually beneficial to both gas operators and utilities. That is, those commitments

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[1] One major action was the Federal Energy Regulatory Commission issuance of Order No. 436, which permitted pipelines to become open-access transporters for gas bought directly from producers by all customers. As a new feature in long-term contracts, market-out clauses grew substantially after the passage of the Natural Gas Policy Act in 1978, reflecting the desire of both buyers and sellers to negotiate contracts that would give them the ability to adapt to changing market conditions. A market-out clause allows the pipeline not to take delivery of gas at the contract price if the gas cannot be resold profitably. [Doane and Spulber 1994.]

[2] Costello 2012. Especially with the advent of open-access transportation, the volume of gas traded in the spot market grew rapidly. For example, spot market gas grew from near zero in 1982 to about 55 percent of total gas deliveries in 1987. [Doane and Spulber 1994, 485.]

[3] Ibid.

can be a good deal for both utilities and gas producers, many of whom are struggling because of low natural gas prices.[4]

B. Vertical arrangements as an option

Proposals for long-term gas procurement by utilities have come in different forms; for example, *long-term contracts between a utility and an independent entity* (e.g., gas producer or marketer), *utility ownership of gas reserves* (i.e., acquiring ownership interests in natural gas reserves), and *joint agreements between a utility and an exploration and production (E&P) affiliate*, and variations of these forms. With the exception of the first – long-term contracts with an independent entity – this paper labels the others as "vertical arrangements".

Vertical arrangements have different features and are somewhat nebulous. In his study of electric utilities and their coal mines affiliates, Paul Joskow remarked that:

> Exactly what constitutes vertical integration is far from obvious. Some utilities own a plant themselves and have a mining division or subsidiary that operates the mines. Other utilities own plants themselves, own both coal reserves and the mines, but contract with independent operators to produce the coal. Still other utilities own the reserves, but contract with independent contractors to both develop and operate the mines. In other cases, the plant is jointly owned by several utilities, only one of which has an ownership interest in the mines serving the plant. I classify any of these cases as vertical integration…[5]

What this quote basically says is that in a vertically integrated structure, the utility acquires an input – coal in Joskow's example or natural gas in the context of this paper – not from outside firms but within the corporation itself. The corporation sets the price of the input and possesses ownership or operating rights to the input, or both.[6]

As discussed below, special conditions must hold to justify a utility vertically integrating rather than relying on the open market to purchase an input, such as natural gas. Compared with other commercial structures, like the spot market and contracting with an independent entity, vertical integration has its upside and downside. One upside is the corporation has more control over the price it pays for an input but a downside is that the open market may offer a lower price, especially during periods of surpluses.

[4] *See*, for example, Dismukes 2015; and Fish 2014.

[5] Joskow 1985, 50, fn 15.

[6] Another way of saying this is that the corporation may have common ownership of the output it sells and the input it needs to produce the product or service. One classic example is a utility owning both an electric generating facility and the coal mine located next to it.

The major rationale for vertical-integration proposals by utilities is that current conditions are ripe for long-term gas hedging largely because of (1) the cash flow problems of gas producers anticipated to continue for at least the next few years and (2) the expected longer-term increase in natural gas prices from growing demand.[7] As some utilities have argued, a window of opportunity exists today to stabilize long-term gas costs at attractive price levels for customers. They also contend that the uncertainty over long-term natural gas supply and demand warrants looking at options today to lock in favorable gas supply costs for customers. As one utility stated, the purpose of its proposed cost of service gas (COSG) program with an E&P affiliate is to benefit customers:

> The COSG Program is designed to be a long-term hedging program to reduce the Company's customers' exposure to the volatility of gas prices, to provide long-term price stability through a physical hedge, and to provide an opportunity for customers to pay less than market prices over the long term.[8]

It is plausible that more utilities will propose vertical arrangements for gas procurement before their commissions in the coming years. These proposals raise complex questions for state utility commissions, including whether utilities should place gas-reserves investments in rate base[9], whether self-dealing transactions are in the public interest, the exposure of utility customers to reserves risk, and why suddenly the current interest in long-term hedging by both electric and gas utilities. Commissions should ask themselves the fundamental question: *Under what conditions should utilities get involved with the gas production business either as an owner of gas reserves or as a joint venture with an E&P gas operator?*

C. Focus of this paper

This paper examines utility long-term commitment through utility ownership of gas reserves (UOGR) or a joint venture with an affiliate E&P company.[10] Some utilities like Northwest Natural Gas and Florida Power Light have ownership interest under a joint venture agreement with a non-affiliate. For Northwestern Energy and Questa Gas, the utility has a joint

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[7] One rationale is that since gas prices are currently low, buyers are in a position to bargain for favorable prices. *See*, for example, Aether Advisors LLC 2015; Dismukes 2015; Fish 2014; McKay 2014; Summers 2014; and Swartz and Klump 2014. Since around 2009, growth in gas supply has exceeded growth in gas demand, placing a downward pressure on price.

[8] Vancas 2015, 4.

[9] Utilities allowed to rate base their gas reserve investments include Florida Power and Light, Northwest Natural Gas and NorthWestern Energy.

[10] *See*, for example, Aether Advisors LLC 2015; BRG Energy 2015; Dismukes 2015; Fish 2014; Florida Public Service Commission January 12, 2015; McKay 2014; Oregon Public Utility Commission 2011; Summers 2014; and Walton April 24, 2015.

venture with an E&P affiliate. The vertical arrangements addressed in this paper come in different forms, but they all share the feature of long-term commitments outside the normal market channels of simply purchasing gas without having any ownership or operating controls over gas reserves or fields.

All of the utilities proposing UOGR calculate expected gas cost savings for their customers based on information available at the time – for example, a comparison of gas production costs with market price forecasts – in addition to long-term hedging/price stability benefits and a more secured gas supply.

Vertical arrangements raise several concerns that regulators must grapple with to protect customer interests. One concern is the risk-reward effect on utility customers relative to the utility or its holding-company shareholders.

II. Vertical Arrangements and Proposals by Utilities

A growing number of natural gas and electric utilities are pursuing UOGR (e.g., direct ownership in gas fields or wells) and other vertical arrangements as a long-term hedging tool with the secondary benefit of saving their customers fuel costs over time.[11] Currently only a handful of utilities have such arrangements, and for some utilities the relative amount of gas supply from vertical arrangements is small.[12] But it is likely that they will become more of interest in the future if only because they offer utilities a new source of earnings.[13]

[11] As an early effort, in 2005, the Los Angeles Department of Water and Power led a group of public power utilities in buying natural gas reserves in Wyoming to help ensure a stable supply for its power plants. [McGreevy 2005.] According to one study,

> In 2005 a consortium of public power utilities in California together acquired gas reserves. The group paid $300 million to Anschutz Pinedale Corp. for 38 oil and gas wells on 1,800 acres of the Pinedale Anticline for an expected 112 billion cubic feet of natural gas production over the life of the field. Southern California Public Power Authority (SCPPA) led the acquisition on behalf of Los Angeles Department of Water & Power (LADWP) who acquired 74.5% of the total purchase, Turlock Irrigation District (Turlock), and the cities of Anaheim, Burbank, Colton, Glendale and Pasadena. In its 2005-2006 Annual Report, SCPPA noted 'This purchase, along with similar future purchases, will provide a secure source of gas for the participants, and hedge against volatile prices in the market.' [Aether Advisors LLC 2015, 138.]

[12] For example, less than 3 percent of Florida Power Light's gas supply will come from its joint venture with PetroQuest. [Florida Public Service Commission 2015.] NorthWestern Energy started off small (around 2 percent of annual gas needs) but has grown to about 30 percent as of today. [Moody's Investors Service 2015, 7.]

[13] See, for example, Moody's Investors Service 2015.

Falling natural gas prices along with production growth has shifted producers' thinking to give more consideration to long-term commitments with buyers. Gas producers may view long-term commitments as a way to stabilize their cash flow and revenues, as well as to continue drilling with less internal capital. They may also see less risk from a bearish outlook in which market prices are unlikely to soar far above the contracted price.[14]

A. Basic features

Common features of UOGR include: (1) Cost of service pricing of gas, (2) expected gas-cost savings and stabilized prices to utility customers, (3) rate basing of gas reserves, and (4) imbalanced allocation of risk to utility customers. The typical structure of an UOGR arrangement is an operating/non-operating working-interest model. The joint-venture operating agreement enables the utility to purchase an interest in gas reserves.[15] The utility, which has a non-operating interest in gas reserves, becomes a partner with the operating entity (e.g., E&P company).[16] The utility pays the upfront capital expenditures to fund reserves development and often a portion of the operating costs. The utility has claim to gas reserves in a specified field. Legally, the utility is not a buyer of the gas. The time horizon of an agreement ranges from five years to multi-decade.

A common feature of UOGR arrangements is a transfer price[17] based on the operator's costs. One expectation is that utility customers will see gas-cost savings over the period of the agreement, but the utility makes no guarantee.[18] In their proposals for UOGR, utilities forecast natural gas prices decades out in time (e.g., 10-40 years), which are highly speculative, illogical (as discussed later) and practically meaningless for commission decision-making. Primary

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[14] *See*, for example, Fish 2014; Livsey 2014; and Summers 2014.

[15] The utility's interest could include either production from existing wells or new drilling in partnership with the gas operator (i.e., a "Carry and Earn" approach).

[16] Another structure is for the gas producer to sell a portion of its working interest to a utility or another entity for cash. As discussed in Section II (D), Washington Gas Light proposed this structure in Virginia.

[17] A transfer price applies to transactions within a single corporation. It generally falls outside an arm's-length bargaining process; for example, they are commonly artificial prices established by a firm to allocate costs among divisions. Transfer prices encompass transactions between divisions of a firm or between a firm and its affiliates.

[18] All of the submitted proposals for utility ownership of gas reserves argue that there were expected gas cost savings for their customers based on information available at the time (and many proposals included some type of comparison of production costs versus market price forecasts) and that there were long-term hedging/price stability benefits.

justification for gas reserve ownership would then seem to derive from other than forecasted gas savings over time to utility customers.

One plausible benefit is price stability or hedging. Utilities have different choices for hedging. Whether UOGR or other vertical arrangements is a preferred approach to purchasing natural gas from independent entities in the wholesale gas market demands thorough regulatory review driven by facts and utility-specific conditions.

Typically, the utility would rate base the capital expenditures required to develop the gas reserves. Finally, most of the risks associated with the arrangement fall on utility customers, rather than the utility itself.[19]

B. Real-world examples

As they increase their use of natural gas, some electric utilities want to avoid wide fluctuations in fuel costs by engaging in a joint venture relationship with gas operators. One utility in particular has emerged as wanting to undertake long-term hedging through vertical integration. South Dakota-based Black Hills Corporation (BHC) has announced plans, labeled the Cost of Service Gas Program ("COSG Program"), in Colorado, Iowa, Kansas, and Nebraska to reduce gas volatility for its electric power operations.[20] It has also proposed in South Dakota and Wyoming to undertake long-term physical hedging for both its electric power and natural gas operations. Specifically, it has asked commissions to allow its utility subsidiaries to make ratepayer-financed investments in natural gas resources, including reserves and drilling operations.[21] The utility subsidiaries may directly purchase gas reserves or structure a joint development arrangement, or a combination of both.[22] Black Hills Utility Holdings has its own E&P reserves, which as it argues would facilitate transactions. It predicts that the transfer price under the joint venture agreement would be less volatile than spot prices over time, since it is based on the E&P cost of service.[23]

According to testimony filed in Colorado by Black Hills, investments in gas production should more stabilize natural gas prices over the long term, which the company says would be

[19] This paper later elaborates on the risks to utility customers.

[20] Argus Media 201; Vancas 2015; and Walton October 27, 2015

[21] The utility subsidiaries of BHC, Black Hills Utility Holdings (BHUH), in other words, would have ownership interests in long-term gas reserves. BHUH initiated in July 2008 when BHC purchased certain gas and electric utility operating companies from Aquila, Inc. BHUH is the parent corporation of those operating companies.

[22] Vancas 2015, 17.

[23] *See*, for example, Aether Advisors LLC 2015; and Vancas 2015.

lower than the forecasted market prices.[24] Overall, the company rationalized the COSG Program as an appropriate long-term hedging action:

> Current natural gas prices are not only low relative to historical prices, but are also low compared to alternative fuel prices and global gas prices. There appears to be an opportunity to stabilize long-term gas costs at attractive price levels for customers. And there is uncertainty regarding long-term supply and demand that warrants looking at opportunities to lock in gas supply costs for customers.[25]

As stated in testimony by the company, while long-term financial hedges "may be available on a limited basis, they command a forward price premium, and would subject the Company to assuming significant collateral posting requirements and counterparty credit risk."[26] Company testimony also contends that market offerings of financial hedges and fixed-price gas contracts are "for limited terms and cannot protect customers against longer-term increases in the price of natural gas."[27]

In Utah and Wyoming, since 1981 Questar Gas has operated under a joint agreement with its E&P affiliate, Wexpro.[28] The affiliate develops and produces gas reserves for the utility, and delivers natural gas at its cost of service under the terms of agreement. The agreement enables Wexpro to recover its well costs and earn a return on its capital expenditures. Dry hole risk falls on Wexpro; it only earns on operating wells. The utility estimated that Wexpro I had saved its customers $1.27 billion since its inception in 1981.[29]

An additional program in 2013 known as Wexpro II, allows Wexpro to acquire and develop additional properties and to continue the Wexpro agreement. The new properties, as

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[24] Ryan 2015.

[25] Ryan 2015, 30-1.

[26] Vancas 2015, 9. Incidentally, as stated by Moody's Investors Service (2015,2), owning gas reserves in a partnership arrangement also exposes a utility to counterparty risks."

[27] Ibid., 12.

[28] Livsey 2014; Public Service Commission of Utah 2013; and McKay 2014. Wexpro develops and produces natural gas exclusively for Questar Gas.

[29] Public Service Commission of Utah 2013, 12. Much of those savings occurred during the period 2000-2008, when the market price of natural gas was at an unprecedented high and occasionally in double digits.

with the previous agreement, calls for Questar Gas to pay a price based on cost-of-service. The utility commissions in Utah and Wyoming approved an acquisition under the new program.[30]

Although Wexpro has a rate base, and the cost of the gas it produces depends on that rate base, in addition to its operating expenses, none of those investments or expenses shows up on the books of Questar Gas. Questar Gas simply receives a monthly invoice from Wexpro that flows through the utility's balancing account just like all other gas purchases. In essence, the cost-based price Questar Gas pays for gas resembles the traditional regulated cost-of-service model used to regulate utilities. Wexpro is not subject, however, to the jurisdiction of either the Wyoming or Utah Commissions. Yet, if the audits and oversight of Wexpro's operations find imprudence, the regulators have the authority to act by virtue of its jurisdiction over Questar Gas.

In 2012, the Montana Public Service Commission approved NorthWestern Energy's request to (1) include natural gas production properties in rate base and (2) allow for recovery of expenses associated with the acquisition of the natural gas production properties. The company argued that the purchase of gas reserves will reduce gas price volatility, help grow the company and secure long-term gas supply for customers.[31] In 2013, NorthWestern Energy spent $70.2 million to acquire Devon Energy Production Company's interest in approximately 900 natural gas wells in Montana's Bear Paw Basin. Owned gas reserves meet about 30 percent of annual gas-supply requirements with the company planning to increase this share to 50 percent.[32]

In 2014, the Florida Public Service Commission approved NextEra Energy subsidiary Florida Power & Light's (FPL) request to invest in gas reserves located in Oklahoma. FPL will engage in a joint venture with PetroQuest Energy.[33] Under the arrangement, FPL purchases an interest in natural gas exploration, drilling and production with its customers, in effect, becoming investors in the natural gas business.

[30] The Utah Division of Public Utilities reasoned that given the current low gas prices and the forecast for relatively stable prices going forward, well owners may desire to sell their interests in existing wells, rather than making more sales at today's lower prices. These conditions create a potential opportunity for Wexpro to acquire additional wells on favorable terms.

[31] NorthWestern Energy 2015. Slide 20 states, for example, that "As we continue to add to our natural gas reserves portfolio, we anticipate a reduction in supply cost volatility for our customers."

[32] Aether Advisors LLC 2015, 137.

[33] *See* Florida Public Service Commission January 12, 2015; News Service of Florida 2015; and Walton June 19, 2015.

FPL will spend an estimated $191million to jointly develop up to 38 natural gas wells in southeastern Oklahoma's Woodford shale natural gas field and recover those costs from its customers.[34] It originally estimated that the arrangement could save customers up to $107 million on their electricity bills over the life of the project.[35] The utility remarked that the deal would enable it to lock in gas prices at production costs rather than relying on the spot market price.[36] In 2015, the Florida Public Service Commission approved guidelines under which FPL can invest up to $500 million annually in additional gas reserves.[37]

As a pioneer in unconventional gas procurement, in 2011 the Oregon Public Utility Commission approved a $250 million, 5-year joint venture between Northwest Natural Gas Company ("NW Natural") and Encana Oil & Gas (USA) to develop gas reserves in Wyoming.[38] The arrangement involves NW Natural providing partial funding for drilling. In return, the utility earns a working interest in a defined portion of the field.[39]

NW Natural argued that its investment in gas reserves would provide some price assurances to its customers over the long term.[40] The Commission ruled that the arrangement is prudent and beneficial to the utility's customers.[41] Specifically, the Commission found the arrangement favorable to customers by:

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[34] Investments in specific wells are more risky than investments in gas fields, mostly because of less diversity. *See*, for example, Moody's Investors Service 2015, 5.

[35] Florida Public Service Commission January 12, 2015.

[36] Ibid. The Commission ruled that customers have significant exposure to price volatility, partially because of the expected increase in natural gas demand from LNG exports and electricity generation.

[37] The guidelines, among other things, restrict FPL's transactions to proved and probable reserves, and "gas reserve" projects as a percentage of average daily burn of natural gas (rising from 10 percent in 2016 to 20 percent in 2018). *See* PalmBeachPost.com 2015.

[38] The main source for the following discussion is Oregon Public Utility Commission 2011.

[39] The initial contract terms have changed, among other things, to specify single-well interest rather than the original field interest. E&P ownership shifted from Encana Oil and Gas to Jonah Energy. The overall effect of developments since the original contract has been to increase risks to NW Natural and its customers. [Moody's Investors Service 2015, 6.]

[40] *See* Fish 2014; and Summers 2014.

[41] So far, it appears that the transaction has been a bad deal for the customers of NW Natural. Since its inception, market gas prices have likely fallen below the contract price. *See*, for example, Moody's Investors Service 2015, 6.

1. *Reducing the utility's gas costs over time by an estimated $52 million in present-value terms:* The utility estimated that the average price of gas under the arrangement would be $5.15 per dekatherm, which is less than the projected market price from various sources.

2. *Mitigating price volatility as a hedge:* The arrangement allows the utility to procure a portion of its gas supplies at stable prices. One benefit is that it will protect customers from sharp price increases, especially those that last for an extended period.

3. *Providing the utility with a reliable long-term supply of gas.*

4. *Allocating fairly the benefits and risks between utility shareholders and customers for any residual risks:* The Commission ruled that the meaning of prudence narrows to the utility's decision to enter into the arrangement and *not* to how it manages the contracts underlying the arrangement.[42] It also required NW Natural to absorb some of the risk when actual gas costs under the agreement deviate from the forecasted levels.[43]

C. Elaborating on the rationales for vertical arrangements

1. Long-term hedge

One motive for UOGR and other vertical arrangements cited by utilities is that they provide the only feasible long-term hedge.[44] *Hedging* refers to an economic activity in which a

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[42] For example, the utility can be subject to prudence challenges for its future drilling decisions.

[43] Specifically, the sharing mechanism of NW Natural's purchased gas adjustment (PGA) clause calls for it to absorb $1 million of the first $10 million of any under-forecast of gas costs. The utility will pass through all variances in excess of $10 million to customers through the PGA. [Oregon Public Utility Commission 2011, 9.]

[44] About the optimal time duration of a hedging arrangement, two opposing forces come into play. The first, favoring longer-term hedging, derives from the cost of transactions on a period-by-period basis (for example, annually, or even more frequently, as in spot-market purchases) which could accumulate to a large amount over time. The second, making longer-term hedging less appealing, relates to the risk of being constrained under an inflexible arrangement over a longer period of time. Inflexibility has a potentially high cost in a volatile market. It can lead to the utility overpaying for gas (relative to the market price) or being required to take gas that it does not need (under a physical hedge). It explains why, in a market where price and supply are difficult to predict, parties are reluctant to make long-term commitments with rigid terms and conditions. Overall, such commitments prevent a utility from taking advantage of favorable market opportunities as they arise.

party protects an existing or anticipated physical market exposure from unexpected or adverse price fluctuations. Parties hedge to lock in both a price and the quantity subject to that price.

Hedges come in both physical and financial forms: Utilities can use storage or bilateral physical contracts with fixed prices as hedges; they can also purchase financial hedges, such as futures contracts, options, and swaps.[45]

Even though the U.S. has an abundance of natural gas and currently low prices, gas prices are inherently volatile, although less so than prior to the shale-gas revolution. Utilities have argued that financial hedges are short-term and physical hedges in the form of long-term contracts with an independent entity are scarce.[46] Some utilities in their applications to state regulators explained, for example, that long-term, fixed-price contracts were generally not available in the market[47]; utilities have also noted that credit/counterparty risks underlie long-term contracts, making them less attractive.[48]

A reasonable concern is that because of much uncertainty over the future demand for natural gas, prices in the years ahead could fall within a wide range. Gas exports could spike, the expectation is for high growth of natural gas for electric generation because of the EPA

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[45] Futures prices can function as a reference point for forward contracts between customers and suppliers of gas.

[46] Utilities could enter into a financial hedge, but such hedges are usually no more than two years (Costello 2012), and, besides, they would not actually secure the physical supply. Both physical and financial hedges require credit facilities to protect counterparties against market price volatility, creating an additional risk and cost to consider when choosing those options.

[47] *See*, for example, Benton 2015; and Garza 2015.

[48] There are few examples of long-term physical fixed-price gas commodity contracts in the U.S. gas industry. The most publicized one is the Public Service Company of Colorado contract with Anadarko that was part of the utility's emissions reduction plan (coal plant retirement/conversion to gas units) in 2010. In Docket 10M-245E, the Commission found a proposed contract between Public Service Company of Colorado and Anadarko to be beneficial to customers and in the public interest. The utility calculated that the contract could reduce its discounted revenue requirements by $100 million over ten years. It also estimated that the average price of gas under the ten-year contract would be $5.48 per dekatherm. Public Service Company of Colorado issued an RFP for a long-term gas contract, and Anadarko submitted the winning bid. The contract calls for ten years' gas supply at "a fixed price offer with an annual adjustment or escalation." The Commission felt that even though the contract does not guarantee supply to the utility, the utility would have sufficient security and credit support from Anadarko's parent companies. [Colorado Public Utilities Commission 2010.]

Clean Power Plan, natural gas vehicles could take off, and so forth.[49] Each of these happenings, of course, is subject to much uncertainty, which in turn makes future gas prices hard to predict.

Another factor in support of a long-term commitment is the reluctance of some gas buyers to undertake investments that require the purchase of natural gas over a multi-year period unless offered price and supply stability. One such investment is combined cycle gas turbines, whose economics hinge on the price paid for natural gas over the next 20 or so years. Even though natural gas prices have become more stable over the past few years, a common perception is that they are still volatile[50] and will increase in the future.[51] Some gas buyers are therefore hesitant to commit on a long-term basis to a fuel source whose future prices could grow substantially above current levels.[52]

2. Buyer's market

One argument in support of vertical arrangements is that the time is now ripe for utilities to exploit a buyer's market; they may be able to lock in gas supplies at an attractive price.[53] Gas producers may find it advantageous to sign favorable deals from the buyer's perspective because of current financial problems triggered by low gas prices. A long-term commitment could alleviate short-term cash flow difficulties. With the utility providing the capital, the gas operator could avoid incurring additional debt in developing reserves. Overall, conditions might be well-suited for a potentially mutually-beneficial arrangement.

Another argument for UOGR and other vertical arrangements is that utility customers would pay a cost-based price rather than a market-based price, which probably means more stable prices for utility customers and possibly lower prices over time. Utilities have also argued that

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[49] *See*, for example, Aether Advisors 2015; and Ryan 2015.

[50] Costello 2012.

[51] As one analyst has remarked, "The market fundamentals point strongly toward demand rising faster than supply. Natural gas prices will need to rise to drive supply growth to meet demand growth." [Ryan 2015, 30.]

[52] "Long-term" here refers to a time horizon that extends beyond what most analysts predict to be a sustained period of low natural-gas prices.

[53] As gas prices have remained low, some utilities have looked to gas investments for maintaining a long-term and inexpensive supply. But the jury is still out on how those investments will hold up, as the price of natural gas has shown little sign of increasing. Florida Power & Light was among the first states to convince regulators to approve the investments and, as discussed earlier, in 2015 received authorization to pursue gas fields in Oklahoma. The plan did result in customers paying more for natural gas, when compared with the market price, during the initial months. [Walton August 26, 2015.]

drilling shale gas has become low risk with few dry holes, and that UOGR could eliminate the "middleman" profits (e.g., marketers). From the utility perspective, UOGR can also offer utilities higher earnings and tax benefits. According to one study:

> A mid-sized regulated utility could add $200 million a year to its capital base, which in many cases could translate into an annual dividend growth of about 3 percent from just the investments associated with long-term natural gas supply.[54]

3. Lower opportunity cost for gas producers

The interest in UOGR and other vertical arrangements hinges on the U.S. gas market having ample supplies over the next several decades, leading to more stable and predictable prices than those we have seen during the first half of this century. Under these conditions, gas producers and utilities would find long-term commercial arrangements less risky. Gas producers may view long-term commitment, for example, as a way to stabilize their cash flow and revenues. They may also see less risk (i.e., opportunity cost) from a bearish outlook in which market prices are less likely to soar far above a contracted price.

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

D. Regulatory responses so far

The regulatory reaction to vertical arrangements so far has been generally favorable, with one exception: While commissions have approved the Florida Power Light, Northwest Natural, NorthWestern Energy, and Questar Gas proposals, in late 2015 the Virginia Corporation Commission rejected the proposal of Washington Gas Light (WGL).

WGL proposed to secure a long-term supply of natural gas at relatively fixed prices. It wanted to enter into a $126 million, 20-year purchase and sale agreement with Energy Corporation of America ("ECA") to acquire producing natural gas wells in Pennsylvania. Unlike the vertical arrangements that have joint agreements for the development of gas wells, WGL proposed to pay cash for working interest in existing wells in Pennsylvania.[55]

WGL testified to anticipate savings of about $84 million over the 20-year term (or on a present value basis a savings of roughly $21 million over the 20 years). A major motivator of

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[54] BRG Energy 2015, 1.

[55] Aether Advisors LLC 2015, 136.

the proposal, as stated by WGL, was the current market conditions giving buyers leverage in negotiating a favorable deal. For the producer, a fixed price based on its cost of operations would enable it to continue operation with capital inflow by the utility during difficult times.[56]

WGL argued that the purchase of proved gas reserves is a cost-effective way to lock in a fixed cost of gas over a long period. Although the utility acknowledged the possibility that certain costs would be higher than expected, it stated that only a portion of the operating costs would be variable. Besides, operating expenses represent only a small portion of the overall estimated cost of gas. ECA would retain a working interest in the acquired wells and, as argued by WGL would have a vested interest in keeping costs down and operating efficiently.

The Virginia State Corporation Commission rejected WGL's proposal on November 6, 2015.[57] The Commission ruled that under the specifics of the proposal, the potential harm to customers is too great when compared to the potential benefits. The Commission noted that WGL's customers would bear almost all of the risks.[58] The Commission concluded that such an outcome is contrary to the public interest. It also questioned the net benefits to customers relative to WGL shareholders. Finally, it raised doubts over the reasonableness of the costs to mitigate long-term price volatility.[59]

III. Basic Principles of Gas Procurement

A. Hedging and other objectives

Gas purchasing and hedging practices have two distinct parts. The first part involves the utility procuring gas and transportation at a reasonable price to meet expected peak-day, peak-month and seasonal demands. The second part, which has received more attention since 2000 when wholesale gas prices started to accelerate and become less stable, involves managing price volatility (i.e., hedging). A utility can hedge through various means: financial derivatives, stored gas, ownership of gas reserves, joint ventures with gas producers, and forward contracts. The purchase of physical gas to meet customers' demand represents a distinct

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[56] *See*, for example, Business Wire 2015; Carsley 2015; Garza 2015; and Washington Gas Light Company 2015.

[57] Commonwealth of Virginia State Corporation Commission 2015.

[58] These risks relate to gas reserves and production volumes, no guaranteed contingency for gas replacement should wells not produce, 20-year forecasts of the market price of gas, and certain variable costs for gas drilling and production. [Ibid.]

[59] These opinions of the Commissions coincided with the testimony of the staff witness Mark Carsley.

activity from hedging with financial derivatives.[60] Some analysts consider hedging as a value-added, nonessential service that a utility provides to its customers.

Before the advent of financial derivatives in the early 1990s, gas procurement and price-risk management were bundled as a single activity or product – for example, in the form of physical hedges like forward contracts and storage.[61] Until around 2000, gas utilities mainly relied on forward fixed-price gas contracts with producers and storage gas tied to First-of-the-Month (FOM) prices. Today, many utilities combine these physical hedges with financial hedging instruments.

Financial instruments such as futures contracts, options and swaps enable a utility to procure gas and manage price risk as separate unbundled activities. A utility could purchase all of its physical gas on the spot market and, separately, purchase futures contracts to stabilize prices. Overall, conventional gas procurement has a least-cost objective, whereas hedging tries to limit the range of prices to align with consumers' tolerance for risk.[62]

To illustrate, an electric utility wants gas delivered to its power plants when needed; it also wants to pay a reasonable price and to avoid dramatic volatility in the price it pays. The utility should balance these objectives in the long-term interest of its customers. The pursuit of price stability should require evidence showing that customers value less volatile and more predictable retail natural gas or electricity prices. Customers always prefer lower prices to higher prices, assuming no decline in reliability or quality of gas service. Yet, it is not evident that customers would always prefer more stable prices if, in fact, they result in higher expected prices over time or require payment in the form of a "risk premium" to counterparties who are willing to absorb the risk.

B. A portfolio approach

A gas portfolio takes into account the price level of natural gas and its volatility, security of supply, flexibility of gas supply (e.g., ability to adjust supply when conditions change), and gas deliverability. Some industry observers refer to a portfolio as the "best cost" approach to gas procurement. "Best cost" can refer to, for example, a portfolio that achieves the lowest cost for highly reliable service, with moderate price volatility.

The portfolio approach to gas procurement has evolved from the past least-cost paradigm, partly because of wholesale price volatility and a more dynamic gas market.[63] A

[60] Costello 2008.

[61] Costello and Cita 2001.

[62] Costello 2008.

[63] See Costello 2008; and Ryan 2015.

least-cost strategy focuses on cost minimization, but, in the process, might compromise other objectives such as reliability and moderate price volatility. Diversification of gas supplies from different sources and under various market and self-supply commercial arrangements gives a utility more flexibility and protection from uncertain future events. In other words, the utility is better able to adapt to unforeseen events with less disruption and at a lower cost.

Diversification also allows a utility to better achieve different objectives, some of which are conflicting. A utility that buys all of its gas in the spot market, for example, might experience extreme price volatility that can inflict substantial harm on customers.[64] Most electric and gas utilities apply the portfolio approach to their gas procurement practices. In the context of this paper, the question is whether long-term hedging should be part of that portfolio. As far as the author knows, no utility has measured the reduced risk in a utility's gas portfolio from UOGR or other long-term hedging vertical arrangements.[65]

From a narrow technical perspective, gas procurement reflects an optimization problem in which the utility[66] attempts to maximize an "aggregate objective function" composed of different sub-objectives and their relative importance.[67] It occurs in an environment of uncertainty over future demand, prices for gas supplies, transportation-capacity availability, and so forth. Gas procurement must also recognize operational, contractual and market constraints.[68]

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[64] A utility can reduce price volatility, for example, by layering fixed-price physical (forward contracts, storage) and fixed-price financial price hedges.

[65] One common method to quantify the potential losses from high gas prices (i.e., price risk) is what analysts call value at risk (VaR). As remarked in one study, "The more sophisticated risk management programs will use formal statistical techniques to measure and monitor the risk of unhedged natural gas procurement portfolios…For a utility, [VaR] is a measure of how much the unhedged portions of its supply portfolio could change in cost over a given time frame with some stated probability." [Graves and Levine 2010, 34.]

[66] One alternative is for state commissions to take a neutral position on long-term arrangements; they should support them when they are an integral part of a utility's optimal gas procurement portfolio. This position requires commissions to rule on long-term arrangements on a case-by-case basis, and not unconditionally endorse or oppose them.

[67] An analogy is a person trying to buy her preferred car, having to consider all the differing features that cars have and prioritizing them.

[68] Costello 2008.

C. How many commissions think about long-term commitments

1. Major findings of NRRI survey

A 2012 NRRI survey revealed that state utility commissions provide utilities with no special incentives to make long-term commitments and, in fact may discourage them largely because of an unfavorable risk-reward relationship.[69] Six survey findings pertinent to this paper follow:

1. *Few commissions have an explicit policy on long-term gas contracting.* Commissions typically evaluate proposed long-term contracts on a case-by-case basis. Most commissions, in other words, take a neutral policy toward long-term contracts by neither restricting nor encouraging them outright. Some industry observers contend that unless state commissions become more proactive in promoting long-term contracting, utilities will continue to rely largely on short-term financial hedging and other mechanisms to reduce price and supply risks. There is an obvious lack of interest so far by utilities to propose long-term physical gas contracts, especially with an independent entity, before their commissions.

2. *A number of commissions indicated that long-term contracting could be part of a diversified portfolio that mitigates risk.* Many of them recognize that diversification gives a utility more flexibility and protection from unknown future events.

3. *One plausible reason for why gas and electric utilities rely little on long-term gas contracts is that they see little economic gain relative to the risks*. That is, utilities consider long-term contracts to carry an unfavorable reward-risk relationship. As reflected in the survey responses, utilities generally receive no profits from long-term contracts but risk cost disallowances from an after-the-fact review. Hindsight review is more likely when the market price of natural gas falls below the contract price and the long-term contract contains rigid terms and conditions. Compared with owning gas reserves, which can enable a utility to grow its earnings, a long-term physical contract with an independent entity is more likely to have a negative effect on a utility's financial ledger.[70]

4. *Cost recovery for long-term contracts generally depends on their* prudence. Few commissions preapprove long-term contracts, and almost all rely on retrospective reviews to determine their reasonableness. Regulatory commitments in the form of

[69] Costello 2012.

[70] As mentioned elsewhere, utilities have stated that gas producers are reluctant to make long-term commitments. Yet, when the producer is an affiliate or is willing to engage in a joint venture with the utility, this reluctance seems to wane.

preapproval are controversial as a general matter because they can shift virtually all the risks of a costly activity to customers, such as long-term contracting, with rigid provisions and an uncertain outcome. The challenge for regulators is to strike an appropriate balance between credibility to utility investors and fairness to customers. In the extreme, an *ex ante* guarantee to utility investors that the utility will recover all of its costs for a long-term contract would be favorable to investors, but ostensibly unfair to utility customers.

5. *Most commissions allow utilities to hedge and evaluate their hedging practices after the fact through prudence reviews.* Most commissions do not evaluate and preapprove a utility's hedging plan beforehand.[71] Commissions generally allow a utility to recover hedging costs through its PGA, subject to a prudence review.

6. *Most gas utilities hedge with financial instruments and storage.* Much more rarely do they hedge with long-term physical gas contracts.[72] Commissions and gas utilities, for whatever reason, may have a bias against long-term physical contracts. Time horizons for gas hedges generally are one to four years. The time horizon most often reported was one year.

The survey results clearly show that even if independent gas producers have a willingness to negotiate long-term contracts – contrary to what some utilities have said – the utilities themselves would be reluctant. After all, they earn no additional profit and bear the risk of a retrospective review that might penalize them, for example, for "excessive" contract prices. It then seems understandable why utilities would opt for vertical arrangements allowing them or their affiliates to increase their earnings. But, the curious question remains why utilities have recently expressed more interest in long-term hedging.

2. Other commission dispositions

Commissions have a history of frowning upon utilities vertically integrating backward. One example is the reluctance of commissions to approve utilities' owning coal mines. Based

[71] Two possible reasons for this tendency are: (a) Preapproval can have the negative effect of inducing the utility to adhere too strictly to the letter of a hedging plan as a means to prevent later cost disallowances while avoiding prudent actions (e.g., a proposed departure from the plan to take advantage of a market shift) that would benefit customers; and (b) the design of a hedging plan should be a utility matter because of its superior "information" advantage.

[72] Most state commissions and utilities place importance on mitigating price volatility and price risk. Utilities can use different approaches to achieve this goal: (a) staggering of contracts, (b) financial hedging, (c) storage, (d) portfolio diversification and management, and (e) long-term physical contracts with a fixed price or specified price range.

on this history, it is somewhat surprising that more commissions have not rejected utility proposals to own gas reserves or purchase gas from an affiliate.[73]

From the author's observations and the NRRI survey, commissions are also hesitant to pre-commit to long-term contracts. Utilities have generally argued that they need a regulatory commitment to avoid hindsight review or what they would consider regulatory opportunism. Commissions, on the other hand, often see a commitment as excessively shifting risk to customers and potentially creating a "moral hazard" problem.[74] There is also a limit to regulatory commitment in that a current commission giving preapproval is likely unable to bind a future commission.

Regulatory commitments are controversial because they can assign to customers virtually all the risks of a costly new investment with uncertain benefits. Regulators are understandably reluctant to bet customers' money on a long-term agreement, especially with an affiliate or when the benefits to utility customers are dubious.

A reasonable standard for regulatory commitments was aptly expressed in one article:

> For utility investors, it is not the tiny details that matter, but whether there is a *credible commitment* to treat both utility customers and utility investors *fairly*, over the short and long runs. Public utilities are regulated to protect utility customers from the consequences of the unfair exercise of market power.[75] (Emphasis added)

The key words here are "credible commitment" and "fairly". The challenge for regulators is to strike a balance between credibility to investors and fairness to customers so as to best serve the public interest. In the extreme, a commitment to utility investors that the utility will definitely recover all of its costs for a long-term agreement, even before it is executed, would seem to violate this balance.

One regulatory tool that can affect the inclination of a utility to make a long-term commitment is guidelines. Guidelines can act as "safe harbor" rules that reduce utility uncertainty in addition to mitigating opportunistic hindsight reviews. Increasing the certainty of cost recovery enhances the willingness of a utility to make a long-term commitment, either

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[73] Probably one should not make too much of this, as the sample size for commission approval is small.

[74] Reducing the risk to a utility, for example, will encourage the utilities to invest in gas reserves. But shifting too much risk to customers might violate the regulator's sense of fairness and create a "moral hazard" problem in which the utility lacks adequate incentive to act prudently. Achieving the proper allocation of risk between utilities and ratepayers is a major challenge for regulators in vertical arrangements as well as in other situations.

[75] Gordon et al. 2011, 10-11.

in the form of a contract with an independent entity or a vertical relationship. Regulatory guidelines can include criteria for acceptable long-term arrangements, commission procedures for reviewing and evaluating long-term contract or agreements, articulation of the role that long-term commitments can play in a utility's gas portfolio plan, and the conditions under which the regulator would tend to favor long-term commitments and thereby allow recovery of the costs.

IV. A Digression on Hedging

A. Hedging 101

In evaluating proposals for both short- and long-term hedging, including those embedded in vertical arrangements, regulators should know basic things about hedging itself:[76]

1. *Customers always prefer lower prices to higher prices, assuming no decline in reliability or quality of gas service. Yet, it is not evident that customers would always prefer more stable prices if, in fact, they result in higher expected prices over time or require payment in the form of a "risk premium" to counterparties who are willing to shoulder the risk.*[77] Cost savings are not the reason that firms hedge.

2. *Price volatility, in and of itself, is not a bad thing if properly managed, and it commonly occurs in many well-functioning markets.* On the flip side, stable prices are not always good. Few readers would dispute that a hedging program fixing the price of gas at $10 per Mcf over the next ten years would not be in the best interest of utility customers. Hedging creates the risk that a utility and its customers will pay above-market prices.[78]

3. *The optimal hedging plan depends on utility customers' tolerance for upside and downside risks*. A utility giving up the ability to take advantage of falling and unexpected price declines, for example, is a real cost of hedging for utility customers.

[76] The following discussion borrows heavily from Costello 2011.

[77] Proposers of UOGR and other vertical-arrangement proposals contend that long-term hedging through ownership of gas reserves or purchases from an affiliate at a cost-based price would achieve both more stable prices and lower long-term expected price; i.e., through vertical arrangements, long-term hedging would require no or minimal cost. One interpretation is that hedging can be a "free lunch" activity, which by itself should be subject to scrutiny by a commission.

[78] An example is when a utility purchases a futures contract in the summer to hedge for the following winter at a price higher than the actual winter cash or market price. Another example is when a utility sells a put option and the buyer exercises it when the market price falls below the strike price.

4. *People and entities purchase insurance generally only for adverse events that have substantial consequences (e.g., auto accident, house fire or invasion, expensive jewelry, death or serious injury).* A fundamental question is whether gas hedging protects against events that are consequential enough to warrant the costs. First, it is uncertain how much value utility customers place on more stable prices, or the avoidance of extremely high prices.[79] Second, the *ex post* costs in some real-world experiences have ostensibly far exceeded the benefits that customers have received from utility hedging.[80] Even in other instances, in which hedging costs are moderate, hedging may not be a bargain for utility customers.

5. *In mitigating upward gas price spikes, utilities should strive to manage regret or rigidity in the downward movement in price.*[81] In view of our optimistic gas supply situation, this objective is particularly critical in the future.[82] A potentially large cost of hedging is the inability of a utility to take advantage of falling gas prices.**[83]** Thus, the decision whether and how to hedge, in addition to seeking protection against upward price spikes, should also limit "losses" in a falling price environment.[84]

6. *Regulators want utilities to hedge to protect their customers from high prices.* The benefits must relate to the willingness of customers to pay for less price risk. One plausible benefit derives from customers knowing that they will not have to pay extremely high prices for natural gas during the winter heating season. This

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[79] One could legitimately ask the following questions: Although perhaps at most an inconvenience for most households and businesses in that less money is available to spend on other goods and services, high gas bills can be economically devastating to some, namely, low-income households; that is, inflict large real income loss for these customers. So are we then addressing only a low-income problem? Or, is the problem more broad-based affecting all or the majority of customers, who may be risk averse in the sense that they would be willing to pay a non-minimal amount for more stable prices and, in the process, avoid having to pay extremely high gas bills during the winter months?

[80] *See*, for example, Costello 2011.

[81] *See*, for example, Costello 2013; and Gettings 2010.

[82] There are divergent views on how low natural gas prices will go given our optimistic future supply situation.

[83] This cost is not inherent in hedging; it is just a feature of a fixed-price strategy.

[84] *See*, for example, Gettings 2010.

"insurance" benefit is difficult to measure.[85] Regulators should require their utilities, however, to make their best effort to measure this benefit as accurately as possible.

7. *Hedging can have different objectives.* They can include locking in a certain price, confining prices within a specified range, or protecting against price spikes.

8. *Hedging has different costs.* They include transaction costs[86], premiums for call options, losses from closed positions (e.g., futures contracts, put options), brokerage fees, margin and collateral requirements[87], personnel or consulting fees for hedging expertise, the cost of computer software, and risks from price-forecast errors, faulty hedging strategies and poor judgment.

9. *The challenge for utilities and regulators is to determine whether the actual and potential costs of hedging are less than the benefits.* Hedging benefits as well as some of the costs are difficult to quantify. Both utilities and regulators must judge the amount of hedging and the hedging instruments to use in a specific market and other situations, let alone determine whether any hedging is optimal. Hedging is a

[85] In practice, it is difficult and expensive for utilities to acquire data on how much the "average customer" would be willing to pay for the utility to hedge and, therefore, to determine whether hedging costs are commensurate with the benefits. In addition, not knowing the degree and nature of customers' preference for price stability also makes it hard for both the utility and the regulator to determine the right mix of hedging instruments. For example, if evidence points to customers concerned with avoiding catastrophic prices, such as natural gas prices above $8 per Mcf, then futures contracts might be the preferred financial instrument, rather than swaps, collars and options. If the objective is to avoid extremely high prices but to allow the utility some flexibility if market prices decline, the optimal approach for a utility might be to purchase call options (assuming that they are not overly expensive) with a strike price of $8.

[86] All of the financial instruments have transaction costs. They also involve a shifting of risk from the utility to, say, speculators that operate in derivative markets. To the extent speculators take on more risk, they expect to be compensated accordingly. This cost is more indirect and, thus, difficult to quantify, but it is no less real. In short, by having a hedging plan that contains financial instruments, the utility will incur transaction costs and risk-compensation costs. These are the costs that a utility could avoid by not hedging. Differences among the hedging tools are evident. Call options, for example, require the upfront payment of a "premium," and futures contracts require a margin account. For vertical arrangements, transaction costs can include the time and effort exerted to negotiate a joint venture agreement and then for the utility to monitor the agreement to ensure that its interests are not jeopardized. Utility management costs to carry out these tasks can be substantial.

[87] When natural gas prices decline, for example, the counterparty to the utility often requires collateral from the utility to compensate for the risk of the utility not paying the transacted price and, instead, purchase lower-priced gas from someone else. The collateral, referred to as a "margin call", could be cash or a letter of credit.

complex activity that requires expertise and good judgment. Without these attributes, a utility can easily design and execute a hedging plan that is harmful to customers.

10. *Hedging frequently produces losses.* Regulators should not expect losses, however, to be large for almost all years. Regulators should also not expect hedging to lower a utility's purchased gas costs over a multi-year period. Instead, hedging would tend to cause customers to pay higher prices over the long term and in most years, but at the benefit of protecting customers against "unacceptable" prices or price volatility. Good hedging strategies balance price risk with the risk of hedging itself.[88] The latter risk includes "regret," in which after-the-fact the utility and its customers would have been better off without hedging. Hedging also introduces other new risks like counterparty risk and collateral obligations.

11. *The utility's interest might not coincide with customers' interest.* The utility might have a lower price-risk tolerance than customers do. The utility also might lack strong incentives to design a least-cost plan or a plan that maximizes customer benefits. Hedging, given the incentives utilities face, requires active regulatory involvement upfront.[89] Bad incentives lead to subpar utility performance. If regulators are unable to provide utilities with good incentives, they should think seriously about whether utilities should hedge at all, unless they have the ability to adequately evaluate the soundness of a utility's hedging strategy.

12. *Utilities should achieve the desired price stability at least cost.* Some utilities, for example, might prefer swaps and futures over call options, which they deem too costly relative to their benefits.[90] For longer-term hedging, the choice narrows down to physical contracts with an independent entity and a vertical arrangement.

One historical note is that utilities have actively hedged since the beginning of this century. Pressures from state commissions in addition to the frequency of volatile wholesale gas prices largely explain utilities' willingness to hedge. A major motivator for utilities to hedge is protection against volatile gas prices for which regulators might hold them accountable. Regulators assume the role of a customer agent in demanding moderate price risk. Utilities' hedging activities seem driven by the desire to minimize cost disallowances that might result from regulatory actions.[91]

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[88] Gettings 2010.

[89] *See*, for example, Costello 2014.

[90] Costello and Cita 2001.

[91] Costello 2011.

B. Hedging options

Most state commissions and utilities today place some importance on mitigating price volatility. Utilities can use different approaches to achieve this goal: (1) staggering of contracts, (2) financial hedging instruments, (3) storage, (4) portfolio diversification and management, (5) long-term physical contracts with an independent entity that contain a fixed price or specified price range, and (6) vertical arrangements; for example, utility ownership of gas reserves and gas purchases from an affiliate.[92]

Utilities hedge in different ways, even those located in the same state.[93] The best strategy for an individual utility depends on several factors, including hedging objectives, market conditions, the utility's size, commission policy on hedging, and the costs and availability of physical and financial hedges.[94] These factors warrant utilities along with their commissions to periodically review hedging strategies following changed market conditions and updated information.[95]

V. Different Commercial Transaction Arrangements

There are three distinct categories of commercial transactions: *spot market, contracting, and internal organization*. The last category, the focus of this paper, occurs when a firm is vertically integrated and looks to itself rather than the market for purchases of required inputs, like natural gas for electric generation and for resale to households and businesses.

A. Spot-market trades

Spot-market trades are extremely short-term transactions for which prices depend largely on short-run supply and demand. Spot trades involve the trading of a commodity for immediate or near-term use. For natural gas, these transactions involve sales within the following 30 days; that is, a utility will use the spot market to buy natural gas for the next day or month.

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[92] Ibid.

[93] *See*, for example, Costello 2011; and Ryan 2015.

[94] Physical hedges include stored gas, a diversified gas portfolio, and long-term contracts that have fixed prices. Financial hedges include futures contracts, options and bilateral over-the counter (OTC) financial instruments. Futures contracts are derivatives of physical commodities while options on futures are themselves derivatives of futures contracts. The value of a financial instrument derives from a cash market commodity, futures contract, or other financial instruments. Parties trade these instruments on regulated exchange markets or over-the-counter.

[95] Costello 2011.

Spot-market trades provide flexibility to the buyer in balancing supply with demand. They also require repeated trading, which over time can drive up transaction costs.[96] Well-developed day-ahead and monthly spot markets for natural gas have thrived since the late 1980s. The U.S. has several spot markets with a large number of sellers and buyers transacting natural gas and other services.[97]

A spot market usually has several pipeline interconnections. Spot transactions based on standardized North American Standards Board (NAESB) contracts provide individual buyers with much assurance of a reliable supply. Suppliers make a "best effort" to provide gas.

Spot prices, in addition to reflecting short-term supply-and-demand movements, also depend on anticipated future prices. Because gas is a commodity, spot prices can change quickly and fluctuate widely, with the timing of gas purchases affecting a utility's actual gas costs. Several factors can influence the spot price of gas, including production cost, storage levels, economic conditions, weather, pipeline capacity, and random shocks (e.g., events in the Middle East or government legislation affecting oil prices).

In sum, spot-market gas purchases are short term in duration and consummated at the then-current (or roughly current) market prices on a monthly, weekly, or daily basis. Because spot-market prices are ever changing and depend on supply and demand, and market conditions, they can be susceptible to significant fluctuations. Since the shale phenomenon, however, spot prices have become less volatile, especially on the upside.[98] Highly liquid

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[96] Nobel Prize winner Ronald Coase defines transaction costs as the following:

> [T]here were costs of using the pricing mechanism. What the prices are have to be discovered. There are negotiations to be undertaken, contracts to be drawn up, inspections to be made, arrangements to be made to settle disputes, and so on. These costs have come to be known as *transaction costs*. Their existence implies that methods of coordination alternative to the market, which themselves are costly and in various ways imperfect, may nonetheless be preferable to relying on the pricing mechanism… [Emphasis added]
>
> [Coase 1994, 7-8.]

[97] U.S. gas spot markets have low transaction costs. The spot market for natural gas is a highly integrated one, especially between the East Coast and central regions. Co-integration of regional prices confirms what economists call the "law of one price." This law refers to the high correlation of prices across regions. Analysts can apply statistical techniques to test the hypothesis of co-integration. With co-integration, arbitrage effectively narrows regional price differences to transportation and transaction costs. *See*, for example, Federal Energy Regulatory Commission 2010, 13.

[98] The reason is that in the pre-shale gas era gas prices were highly sensitive to fluctuating demand, given gas-supply scarcity. [*See*, for example, Costello et al. 2005.] Because of a quicker and

markets, such as for spot gas, allow buyers to easily and at low costs change suppliers and, according to some observers, eliminate the need for long-term contracts and vertical arrangements. This assertion, however, is far from widely accepted.

B. Long-term contracting

Contracting represents what analysts call an "in-between" transaction for which the seller and buyer rely on markets, but they desire more certainty in price and other attributes of a trading arrangement than available in a spot-market trade. Contracting has several dimensions that are negotiated between the buyer and seller, with the outcome largely dependent on current and future market conditions, the risk aversion of the buyer and seller, and the relative bargaining strength of each party.

Contracting involves the utility making decisions on the duration of a contract, the original price level and the pricing mechanism, the options for changing the purchase price and volume over time, and other terms and conditions. To enhance the price stability of its gas portfolio and reduce exposure to the volatility of the spot market, many utilities rely on short-term fixed price contracts. These contracts typically provide gas at fixed prices for a period of two years or less.[99]

In sum, long-term contracting represents a transaction in which the seller and utility want more certainty in price over the next several years than what spot-market transactions can offer. The negotiating parties also might want to customize other non-price terms in conformance with their unique needs. The parties' risk aversion, as well as market conditions, plays a large role in a contract's negotiated terms. Evidence of risk aversion is the higher price that a buyer would be willing to pay to have more stability of price over time.

C. Vertical integration

As noted by Paul Joskow,

> *Vertical integration* represents an alternative governance structure to bilateral contracts for mediating the supply of a product that requires specific investments to support cost minimizing exchange. Rather than fiddling with contractual protections to mitigate the inherent conflicts of interest that may arise between independent buyers and sellers in the presence of specific investments, and dealing with other distortions and rigidities that such contracts may entail, the buyer may choose instead to integrate backward (or

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more intense response on the supply side to market price changes, shale gas has caused prices to be less volatile.

[99] *See*, for example, Aether Advisors LLC 2015.

> the seller integrate forward) into the supply of the input at issue (or sale of the downstream good).[100] [Emphasis added]

Joskow is basically saying that contracting can cause high transaction costs, especially in situations where, during its duration, at least one of the parties may find it advantageous to breach or terminate the contract that could impose damage on the other party.

A number of conditions are conducive to vertical integration: Technical interdependency (economies of scope[101]), market failures, high transaction costs for market trades, structural imperfections, and uncertainty about input supply. Integration can reduce transaction costs and better harmonize interests (buyer and seller),[102] allowing for an efficient decision process. On the down side, a firm increases its risk when it extends its domain to upstream non-core business (e.g., gas production). Another negative aspect involves integration between two affiliates when one of them is subject to price regulation (a matter that we will come back to later). None of the reasons in support of vertical integration, as discussed later, seems particularly valid for utilities procuring their natural gas within the utility itself or the holding company.[103]

D. What does economic theory say?

Economic theory has much to say about the preferred commercial structure for gas procurement. Specifically, transaction cost economics (TCE) offers predictions of the most efficient and likely arrangements for gas procurement. Transaction costs are costs (excluding

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[100] Joskow 2005, 333.

[101] *Economies of scope* measure the difference between the sum of the cost for providing regulated and unregulated service by separate entities and the cost to one firm (e.g., utility, holding company) providing both services. High transaction costs from market trading, for example, can justify a firm looking inward to supply an essential input (i.e., vertically integrate). Alternatively, some economists use the term *economies of sequence*, which are cost reductions resulting from a single firm vertically integrating two or more distinct business activities; for example, a firm producing steel to make widgets that it sells on the open market).

[102] As stated by Joskow (2005, 321),

> The potential advantage of internal organization…is that internal organizations are likely to better harmonize…conflicting interests and provide for a smoother and less costly adaptation process under [certain] circumstances, facilitating more efficient *ex ante* investment in the relationship and more efficient adaptation to changing supply and demand conditions over time."

[103] Integration can include a utility owning gas reserves but contracting with an operator to drill and produce the gas; and a utility having a gas division or subsidiary that operates the gas wells.

the price) that firms and consumers incurred in consummating a trade. They include the costs of trading parties to find each other and then to negotiate, draft, monitor, and enforce contracts. Studies have found them to be good predictors of the prevalent commercial structure (spot markets, long-term contracting, and vertical integration) across a variety of markets.

Transaction cost-based theories of vertical integration pioneered by Oliver Williamson focus on the implications of incomplete contracts, asset specificity[104], information imperfections, incentives for opportunistic behavior, and the costs and benefits of internal organization.[105] These theories address the efforts by firms to mitigate transactions costs and various contractual hazards that may arise with transactions in the open market. These efforts include choosing among alternative organizational and contractual governance arrangements that enable them to reduce these costs.[106] There is substantial empirical support for these theories.

According to Williamson, vertical integration (or internal organization) is a last resort that firms should only consider with significant contract hazards and transaction costs.[107] The transaction costs associated with contracting derive from: (1) search and information acquisition, (2) initial negotiation, (3) monitoring, (4) enforcement, (5) haggling at contract renewal, and (6) deviation of evolving market conditions from contract terms and conditions. When these costs are high relative to the transaction costs of vertical integration, contracting

[104] *Asset specificity* refers to a characteristic of an investment that has an alternative value much lower than its value in its original use. This condition makes investments vulnerable to "hold up" or "opportunism" by the buyer. A seller, for example, might receive lower revenues because the buyer threatens to terminate a contract if not offered, during the duration of the contract, a lower price or other more favorable terms and conditions. The seller might agree to a lower price if only because other buyers would assign less value to its product. One classic example of asset specificity is a coal mine that is located next to an electric generating facility. The mine has really only one buyer, so it would likely require a commitment from the utility to purchase its coal over several years. *See*, for example, Joskow 1987.

[105] *See* Joskow 2005; and Williamson 1979 and 1996.

[106] Neoclassical economics generally viewed vertical integration downstream and upstream as being unnecessary for a firm to produce at minimum cost in the absence of technological relationships that physically joined production between plants. Instead, the presumption was that vertical integration, and non-standard vertical contractual arrangements more broadly, reflect efforts by firms to exploit market power. Thus, reactions to or efforts to create market power were the fundamental bases for neoclassical theories of vertical integration. One example is oil producers vertically integrating with pipelines because of the "rent extraction" activities of a monopsonistic pipeline. *See*, for example, Klein et al. 1978, 310-13.

[107] Williamson 1996, Chapter 4.

becomes less attractive. As a preliminary observation, these conditions do not seem to hold for utilities procuring natural gas.

1. Specific insights from TCE

Transaction cost economics (TCE) predicts the market conditions under which vertical integration is a preferred institutional arrangement over long-term contracting and spot market transactions. When asset specificity, sunk costs, and a high degree of complexity (e.g., the buyer requires a product to have exact specifications of a high technical nature) characterize a trade, vertical integration can become the most efficient alternative.[108] As the contractual process becomes highly complex, for example, a firm might turn to self-supply a required input rather than purchasing it in the marketplace to avoid the high transaction costs in negotiating, monitoring and enforcing a complex contract. On the other hand, firms should be less vertically integrated as the cost of using the marketplace to purchase an input decreases. For example, a more liquid wholesale gas market would increase the attractiveness of spot markets relative to long-term contracting and vertical integration.

Regulators should ask whether the rationales for UOGR and utility purchase of gas from an E&P affiliate are compatible with conditions conducive to vertical integration as predicted by TCE. The insights gleamed from TCE are many, which can help regulators determine the degree of compatibility:

1. Simple spot transactions afford much flexibility and minimal commitments of parties, but can discourage companies from making certain investments because of hold-up or opportunism.[109]

2. Contracting attempts to attenuate such hold-up problems by defining acceptable behavior (e.g., no breaching of a contract by the seller when the market price unexpectedly increases) at the outset of a relationship.

3. When the hazards of spot markets and contractual exchange are severe, vertical integration offers potential ownership and governance advantages.[110]

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[108] Other conditions favoring vertical integration include uncertainty of outcomes and small-numbers trading (i.e., a non-competitive market). The latter condition means that a firm may want to vertically integrate to avoid being victimized by high prices from the exercise of market power.

[109] Hold up or opportunism is an attempt to influence terms of trade in one party's favor.

[110] As remarked in one study:

> According to transactions cost theory, when exchange involves significant investments in relationship-specific capital, an exchange relationship that relies on repeated bargaining is unattractive. Once the investments are sunk in anticipation of performance, "hold- up" or

4. Costs associated with monitoring contracts would not exist with some forms of vertical integration; that is, the incentive problems and risk-bearing costs of contracting can decrease with vertical integration.

5. The costs of vertical integration are bureaucratic inefficiencies from the incentive problem and the limited capacity of management to undertake additional activities; these inefficiencies plague most large organizations.[111]

6. Relationship-specific investments usually require a long-term commitment by the user.[112] The potential for opportunism in the absence of a long-term commitment could lead to underinvestment.[113]

7. TCE emphasizes *ex post* adaptation issues and associated bargaining and performance costs, recognizing that these costs also affect incentives for

"opportunism" incentives are created ex post which, if mechanisms cannot be designed to mitigate the parties' ability to act on these incentives, could make a socially cost-minimizing transaction privately unattractive at the contract execution stage.

[Joskow 1987, 169.]

[111] A vertically integrated firm incurs costs when self-supplying one of its inputs. These costs include contracting with employees and supervising them. Buying the input in the marketplace requires the firm to contract with sellers and monitor the quality of the input. These are the transaction costs of buying an input in the marketplace. Competitive pressure would induce firms to minimize their costs by selecting the cheaper alternative between buying and self-supplying the input.

[112] Economists sometimes refer to these investments as "dedicated assets" where the investor would not undertake them but for the chance to sell their product to a single buyer. *See*, for example, Joskow 1987.

[113] This example is most applicable to the natural gas sector when a shipper, such as a gas utility or electricity generator, requires a new pipeline or lateral off a main line. Here, the pipeline owner might demand a long-term contract with explicit terms and conditions to compensate for its vulnerability from serving only a single customer. The customer might exploit her advantage by threatening not to transport gas over the pipeline unless given a lower price or other more favorable conditions. The pipeline owner may also leverage its position at the expense of the shipper. If contracting becomes too cumbersome or costly, for example, the shipper may decide to own and operate the new pipeline; that is, the shipper could avoid having to deal with an outside party to obtain transportation service.

investment; it stresses the problems of incomplete contracts, relationship-specific investments, and opportunism.[114]

8. Empirical and theoretical studies confirm the importance of transaction costs in determining the most efficient commercial structure.[115] When the transactions costs associated with spot market transactions and non-standard bilateral contractual arrangements reaches a certain threshold, for example, vertical integration becomes a potential alternative governance structure with lower transaction costs.

9. Which category of commercial structure — spot, contracting, or vertical integration—is consummated, as well as which is most efficient, depends on the conditions surrounding a transaction. For example, when asset specificity, sunk costs, and a high degree of complexity (e.g., the buyer requires a product to have exact specifications of a high technical nature) characterize a trade, vertical integration can become the preferred alternative. As the contractual process itself becomes highly complex, a firm might also decide that producing an essential input internally rather than purchasing it in the marketplace avoids the high transaction costs associated with contracting. On the other hand, firms become less vertically integrated as the cost of using the marketplace to purchase a good or service decreases.

10. One condition making long-term contracting or vertical integration more attractive is an underdeveloped or dysfunctional spot, futures, and other financial-derivatives markets. When spot markets are immature and illiquid, and financial derivatives are unavailable, long-term contracts and vertical integration to hedge price and supply become more appealing. Almost all industry observers believe that these conditions

[114] Incomplete contracts, moral hazard problems, costs associated with internal and external monitoring are central to transaction cost theories. Incomplete contracts exclude the obligations of each party to a contract in certain states of the future.

[115] Transaction costs play a crucial role in determining the attractiveness of long-term physical contracts relative to financial instruments. Futures and options contracts have low transactions costs because of their trading in a centralized exchange. A utility, for example, would incur less time and effort to sell a futures contract when market conditions change than to renegotiate or terminate a bilateral physical or financial contract under the same conditions. The futures market is a liquid market with a large number of willing buyers and sellers. (A market is liquid when selling and buying occur with minimal effect on price, or at low transaction costs.) Renegotiation of a physical contract, on the other hand, can lead to high costs for the parties. (The longer the term of the contract, e.g., 15 years, the more it will probably cost to renegotiate the contract's terms.) Although a physical contract has this liability, compared to a standardized futures contract it has the benefit of customizing terms and conditions to the specific needs of the negotiating parties. Overall, although physical and financial contracts are interchangeable, they are not perfect substitutes.

for the natural gas sector do not hold in the U.S.: The country has well-functioning spot markets and an active financial-derivative market for natural gas. Yet, because financial derivatives are short term and long-term contracts are presumably not available, long-term hedging in the form of vertical arrangements might be able to fill this gap.

11. Robust, liquid wholesale gas markets have made spot purchases more economical. The striking trend away from long-term contracting during the past 30 years is the result of the natural-gas industry becoming more open and competitive. The shifting of trade toward shorter-term arrangements, for both gas supplies and transportation, is compatible with the dramatic change in the market environment that has occurred over this period of time.[116]

12. Self-supply through vertical integration involves a utility procuring its gas either within a division of the utility or through an affiliate. One example is an electric utility that supplies itself with natural gas from wells that it owns. Another example is a gas utility buying gas from a marketing affiliate. One challenge for a vertically integrated firm is to avoid higher organizational costs from taking on new activities internally.[117] A firm, for example, might decide to produce the materials needed to make widgets. Management of the firm, which now involves itself with a distinctly different activity that requires new acumen and knowledge, might pay less attention to its core activities.

2. Positives of different commercial arrangements

Spot gas purchases have the advantage of allowing the utility the opportunity to buy cheap gas, since the utility faces no restrictions based on a long-term commitment. Under *long-term contracting*, the utility would face a more secured gas supply and more stable prices, and have available a long-term hedge. Compared with spot purchases, long-term contracting would avoid transaction costs associated with repeated purchases. It could also lessen the short-run demand or supply shocks from a volatile spot market. Because contracts can provide revenue assurances to producers, the utility might be able to negotiate a favorable price.[118]

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[116] In line with TCE, these changes have lowered the relative transaction costs of shorter-term trading arrangements. The market participants seem to be acting rationally in their preference toward shorter-term transactions as the natural-gas market has evolved. *See*, for example, Costello 2005; and Doane and Spulber 1994.

[117] *See*, for example, Williamson 1979.

[118] Favorable pricing by the seller can offer the utility discounts in return for a long-term commitment. This condition can exist when the seller is more risk-averse than the utility by placing a higher value on price stability. What price a utility should pay for gas under contract, and its

Vertical arrangements can help secure gas supply and stable prices, and generally act as a long-term, quasi-hedge.[119] The emphasis of TCE has been on looking for other than traditional vertical and horizontal externality, foreclosure, uncertainty and risk allocation explanations for vertical arrangements.

Two non-traditional explanations are that internal organizational processes are likely to (1) better harmonize conflicting interests that are inherent in typical long-term contracting and (2) provide for a smoother and less costly adaptation under certain circumstances (e.g., a highly unexpected development in gas markets). A vertical arrangement can then facilitate more efficient *ex ante* investment in the relationship *and* more efficient adaptation to changing supply and demand conditions over time. In plain language, this means that when conditions change unexpectedly, or are unanticipated, a vertical arrangement can produce more efficient investments and a less distortive outcome than from contracts. Incomplete contracts, for example, can lead to opportunistic behavior or a breach of an agreement that continues to be collectively beneficial but not to all parties.

3. Negatives of different commercial arrangements

Each kind of commercial arrangement has drawbacks. First, *Spot purchases* are susceptible to volatile prices, and they provide no guarantee of a secured long-term gas supply.[120] *Long-term contracts* are a financial liability for the utility, viewed by investment rating institutions as debt equivalence (or imputed debt).[121] Utilities have also argued that they are not widely available, they pose credit/counterparty risks, and are susceptible to opportunism or default risk[122] by the gas operator. They can also have a high transaction cost

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relationship to the spot price, depends on the relative price-risk aversion of the seller and buyer. If a buyer exhibits more risk aversion than a seller, for example, the buyer would tend to pay more than the spot price (e.g., expected average spot price over the next ten years) to reduce price uncertainty. A buyer operating in a non-liquid spot market might also pay a premium for contracted gas to protect against possible regional supply shortages.

[119] As discussed later, the hedge is quasi in nature since the price and the quantity subject to the hedge are not known with certainty.

[120] When pipeline bottlenecks are the cause of gas supply curtailments, neither long-term contracts nor vertical integration can guarantee gas supply.

[121] Debt equivalence is a measure of the financial risk shifted to a utility when it enters into a long-term contract obligating it to buy, for example, fuel or purchase power. It can jeopardize a utility's creditworthiness if the utility makes no financial adjustments to its capital structure. *See*, for example, The Brattle Group 2008.

[122] Default risk, for example, under a long-term agreement can occur when market conditions vary from what the seller anticipated at the time of signing. *See*, for example, Benton 2015, 18.

for contract negotiation, renegotiation and enforcement,[123] and potentially reduce opportunities for utilities to buy cheap gas on the spot market.[124]

Long-term contracts are able to reduce supply and price risks, but over time they may diverge from the prevailing economic or market value of natural gas under various market conditions. Long-term physical supply contracts would still, to some extent, reflect market price volatility as long-term, fixed-price gas supply arrangements are rarely available. If a fixed price contract is available, the risk is that the gas-supplier counterparty could default if gas prices increase above the *ex ante* anticipated price and the buyer would have to replace that supply in the spot market.

*Vertical integrati*on, which is the focus of this paper, poses risk because of the lack of utility expertise in a non-core activity. It also receives negative marks for an internal utility incentive problem, managerial diseconomies, the risk of gas production being less than expected levels, lost opportunities for the utility to buy cheap gas on the spot market, and potential self-dealing abuse from the perspective of utility customers. When a utility is vertically integrated with an affiliate in its organizational structure, for example, the purchase of gas from its affiliate does not represent an "arm's-length" transaction. The expenditure may therefore not reflect a reasonable cost. Because of the close relationship between the utility and its affiliate, regulatory commissions must carefully scrutinize the transaction to determine whether expenses are reasonable. In a transaction not conducted at arm's-length, the regulator cannot presume the costs incurred are reasonable.

4. Comparison of commercial structures

Table 1 lists the positive and negative attributes of the three commercial structures previously discussed. One conspicuous observation is that the arguments in support of a vertical arrangement for gas procurement seem less than persuasive. The suggestion, short of regulatory prohibition of vertical arrangements, is for a commission to make a rebuttable presumption that a vertical arrangement is contrary to the public interest. The commission should be open, however, to the evidence provided by the utility, which on a case-specific basis might show that utility customers would benefit.

[123] Contracts may be incomplete because of the direct costs of specifying and writing contracts that anticipate all contingencies. What economists call "bounded rationality" makes it unlikely that the transacting parties can foresee all possible contingencies.

[124] Although utilities seem to understate the "lost opportunities" in their proposals for vertical arrangements, it is a downside of long-term contracts or any arrangement that offers more stable prices than spot-market prices.

Table 1: Positive and Negative Features of Different Commercial Structures

Commercial Structure/Feature	Positive	Negative	Comments
Spot purchase	Low transaction costs in a liquid market Utility gets the benefit of a low market price Minimal commitment by both seller and buyer Parties have flexibility Reference price for futures and multiple transactions	Risks of high prices during a supply-constrained situation Contrary to utility/regulator preference for stable prices Transaction costs from repeated purchases	Spot markets have become the predominate form of gas procurement since the late 1980s Most utilities rely heavily on the spot market but complement it with physical contracts and financial derivatives in their gas portfolios
Contracting with an independent entity	Long-term (quasi) hedge Avoidance of repeated purchases More secured supply Assured revenues triggering needed investments	Potential for contract price deviating far from the market price Counterparty/credit risk Collateral requirement Debt equivalence High transaction costs under complex conditions *Ex post* renegotiation	Long-term arrangements are rare Gas producers reluctant to commit long term because of possible opportunity losses from rising prices More secured supply (relative to spot purchases) probably overstated because of liquid spot markets and incidence of supply problems caused largely by transportation constraints
Vertical arrangement (e.g., UOGR, gas purchases from an E&P affiliate)	Lower transaction cost than complex contractual arrangements Economies of scope or integration Long-term (quasi) hedge Potentially more effective than contracting in dealing with incomplete contracts, asset specificity, and opportunistic behavior	Potential for self-dealing abuse Limited supply options and market deals Risk from utility engaged in non-core activities Managerial diseconomies	Conditions conducive to vertical arrangements don't seem to hold for gas procurement by utilities Regulators need to beware of both (1) self-dealing and (2) risk-shifting aspects of vertical arrangements Dubious benefits to utility customers relative to corporate shareholders The only commercial structure for gas procurement where the utility or an affiliate can increase its earnings

VI. The Challenges for Utilities

Historically, a major regulatory decision is to define and measure a reasonable price for a product or service purchased by a utility from a subsidiary or through some other vertical arrangement. For affiliate or other nonmarket transactions, or in the lexicon of economists and accountants, transfer prices usually apply to products or services charged by one segment of an organization to another segment of the same organization.

Generally, transfer prices fall outside an arm's-length bargaining process. They are commonly artificial prices established by a firm to allocate costs among divisions or subsidiaries, or in pricing outside the normal channels of the marketplace; for example, the price charged to utility customers based on gas produced from utility-owned reserves. The prices for coal and information services from utility subsidiaries are two other examples.

A. The price charged to utility customers

The price that utility customers pay for gas owned by the utility or purchased from an affiliate can derive from different approaches. Unlike purchases using the market mechanism, vertical arrangements require a proxy measure of prices that regulators must determine is in the public interest.[125] Listed below are five different approaches for setting prices for gas purchases in a vertically integrated arrangement:

1. **Fixed:** When the fixed price deviates far from the market price, the incentive exists for either the operator or the utility to renege. This is one reason why long-term, fixed-price contracts are rare.

2. **Cost of service:** This pricing mechanism is the most common for natural gas under vertical arrangements.[126] It has the advantage of ensuring that prices are high enough to avoid the incentive of a gas operator to renege on its agreement with the utility because of cost increases or lower than expected productivity changes. These contracts normally specify that the buyer will pay all operating costs, depreciation, amortization, property and severance taxes, plus an allowance for profit. They generally recognize explicitly that because pure cost-plus arrangements raise incentive problems, they should include specific incentive provisions. For example, the operator may lack a strong incentive to keep its costs down. It then becomes imperative for the utility to monitor the operator to ensure efficiency in drilling and production. The operator may also want to avoid lost opportunities by diverting supplies to the market when the price rises. On the other side, the utility may also

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[125] *See*, for example, Joskow 1985.

[126] In fact, it may be the only mechanism used in either actual or proposed vertical arrangements. It is somewhat puzzling why utilities have not considered other pricing mechanisms.

have an incentive to renege if the market price of gas falls far below the agreed-upon price.

3. **Market-based:** The market price approach treats the affiliate as if it were an entity independent from the utility company. This method compares prices relating to the transaction between a utility and an affiliate with those of comparable enterprises.[127] If a regulator does not find the affiliate's price reasonable, it can impute a comparable price.[128]

4. **Escalation or index-based:** One challenge is how to index individual components of drilling and production costs. When the indexed price moves deviates from the economic costs of drilling, either the operator or the utility might have an incentive to breach the agreement, which could lead to haggling and litigation. The advantage of an indexed price over a fixed price or a cost of service price is that it accounts for several important causes of changing supply prices, even though the indexed price may not move in perfect parallel with the prices for competing sources.[129] The buyer might have a strong incentive to renege if the market value of gas falls precipitously.[130]

5. **Competitive bidding:** The utility could issue an RFP to gauge the price at which independent gas producers or marketers would be willing to sell natural gas. This price can represent the highest price at which a utility is able to charge its customers

[127] This comparison makes much more sense for homogenous commodities like natural gas than for commodities that have dissimilar qualities like coal. How would one, for example, compare the price of coal from one source with a higher sulfur content and moisture content than coal from a different source? For natural gas, comparable pricing can correlate with the Henry Hub future contracts, adjusted for basis.

[128] Although the actual price (i.e., transfer price) under vertical integration might differ from the market price, it can rely on movements in the market price over time to set allowable annual price changes.

[129] Price escalator clauses in contracts protect producers from sales at below-market prices.

[130] To avoid bad incentives, indexing provisions in contracts often adjust prices so that the price the seller receives is partially independent of his production decisions. If the seller beats the index, he increases his profits; if the seller does not, his profits fall. Buyers generally recognize that cost-plus profit contracts have poor incentive properties that can lead to inefficient production. *See*, for example, Joskow 1985.

from a vertically integrated arrangement.[131] Competitive bidding also could reveal whether the utility affiliate is truly the "best" gas supplier.[132]

B. The utility as an active and informed participant

In any vertically integrated arrangement in which the utility relies on an outside gas operator, the utility must play an active role in protecting its interests.[133] As remarked by Moody's Investor Service, utility investments in gas reserves are "a non-core activity which adds complexity to supply arrangements, contractual agreements and regulatory oversight."[134]

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[131] Competitive bidding allows the utility fewer opportunities to strategically exploit its information and intelligence to unduly favor an affiliate. The ability of competitive bidding to mitigate favoritism also depends on the design and operation of the bidding process. The RFP process should attract a number of firms to bid; otherwise, over time one firm would tend to dominate. Where a utility's affiliate is a potential bidder, a regulator may especially want to pay close attention to the selection process. A competitive RFP process would help assure an arm's-length transaction, especially if a regulator assigns an outside referee or independent evaluator to review and assess the bids.

[132] The final selection of bids may depend upon rankings of individual criteria and the total score. The utility may apply a quantitative weighting scheme to rank the importance of each criterion; alternatively, criteria may be evaluated and prioritized on a completely qualitative basis. Some of the criteria, such as the E&P gas-operator experience, surety of gas reserves and creditworthiness, could be judged by whether or not they satisfy some threshold. One decision rule is simply to add up the scores for each bidder, weighted by the significance attached to each criterion, and rank the bidders based on the weighted scores. We can express this so-called additive linear (i.e., decision) rule as:

$$V_j = \Sigma w_i s_{i,},$$

where w_i represents the weight assigned to the ith criterion and s_{ij} is the score ascribed to the jth bidder for the ith weight. The aggregate score for each bidder (V_j) equals the bid for each criterion (for example, the score given to a bidder for creditworthiness), summed across all criteria. The score is, therefore, a weighted average score metric, where the weights represent the relative importance of each criterion.

A certain degree of subjectivity and arbitrariness is inevitable in setting, prioritizing, and weighting the criteria, and in the final evaluation of bids. These characteristics of the selection process may offer self-dealing opportunities to the utility. The regulator and non-utility stakeholders, because of asymmetric information, may therefore find it difficult to refute the utility's selection.

[133] Two vital decisions, not discussed here, are the choice of a partner in a joint venture and the gas basin from which gas will flow to the utility.

[134] Moody's Investor Service 2015, 1.

One important utility function is to monitor the operator's performance, especially if the price is cost-based. In this instance, the operator would lack a strong incentive for efficient gas operation. Because the operator has better information than the utility, it would be difficult for the utility to detect and measure inefficiency on the part of the operator.[135]

According to one study, the utility faces stiff challenges in ensuring that ownership of gas reserves is successful:

> The prize of lower natural gas prices, lower price volatility, lower risk supply, equitable allocation of risks and rewards, combined with significant opportunities to grow the capital base of investor-owned regulated utilities, is real but not given. It is critical that regulated utility executives simultaneously solve both the "strategy" and "organizational" challenges that owning natural gas reserves and production present, particularly given the unique attributes…[136]

The same study emphasizes the active role that a utility should play as a non-operating partner :

> [S]ome companies have chosen the common non-operating working-interest owner role. However, this is not a "passive investor" role. As per industry best practice, a non-operating party is provided not only the opportunity but also the expectation to be an active participant in many oil and gas activities within industry-standard joint operating agreements (JOAs). While common industry practice is to refer to parties in JOAs as "partners," it is also industry practice that each party has the responsibility to ensure its own interests are protected. Passive investing, especially in unconventional resources where development never stops, is understood within the industry to not be a best practice and will almost certainly not lead to success… Regulated utility leaders that choose to be non-operating partners still need to decide, before investing, how to build the organizational capabilities to be a non-operating party that adds value through active participation, as well as how to build the capabilities to ensure operators achieve high performance (e.g., achieve industry learning curves).[137]

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[135] The operator's actions affect outcomes while the utility *observes* outcomes. The problem for the utility is to distinguish between performance factors under the operator's control and those outside its control. With an information advantage, the operator can exploit this asymmetry to its advantage. Consequently, the operator can become lax and allow its costs to increase without the utility knowing whether it was because of imprudence (e.g., poor management) or factors beyond its control. The operator would have obvious reason to argue for the latter cause if the matter becomes subject to scrutiny.

[136] BRG Energy 2015, 7.

[137] Ibid., 9.

C. Determining the value of gas reserves

For UOGR arrangements, a utility would need to estimate the value of gas reserves. A regulator would also want this information to compare the benefits of the gas reserves relative to the cost obligations of utility customers.

The value of gas reserves depends on four major factors:

1. The estimated amount of recoverable gas in the ground and chances for recovery,
2. The estimated capital costs for drilling and production,
3. The expected operating costs, and
4. The forecasted market price for gas over the life of the reserves.

All of these factors are subject to uncertainty, requiring regulators to evaluate each of them stochastically.[138] As an observation, under most actual and proposed vertical arrangements for gas procurement when the forecasts turn out to be wrong, most of the risk falls on utility customers. Regulators might want to hold the utility more accountable for erroneous forecasts. For example, they can consider setting a cap on the price of natural gas that customers pay; or establishing a bound for how much the price charged to customers can exceed the prevailing market price.[139]

VII. Long-Term Vertical Arrangements Raise Serious Concerns

Long-term vertical arrangements for gas purchases by utilities raise a number of questions about their effect on utility customers and the public interest. There are several reasons for concern, some more serious than others.

A. A false motive

First, the real motive for utilities seems to coincide with their financial interests. Three motives come to mind: (1) grow the earnings of the utility, its affiliate or the holding company, (2) benefit utility customers from long-term hedging, and (3) produce gas-cost savings to utility customers. The evidence points to the first motive since the expected gas-cost savings estimated by utilities is relatively small and even that may overstate the true savings (to be

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[138] In one case, for example, the level of gas reserves was a major issue, as it has a large effect on the cost-effectiveness of the utility's proposed program. [Carsley 2015.]

[139] As mentioned earlier, Northwest Natural Gas has a sharing mechanism in its PGA that prevents pass through of all gas-cost "overruns" to its customers.

discussed next); and no good reason exists to believe that the long-term hedging benefits to customers warrant the substantial efforts that utilities have made to consummate joint agreements.

On the other hand, benefits to utility shareholders and utility holding companies seem more immediate, certain and substantial. For UOGR where the utility places its investments in gas reserves into rate base, the benefits are much more definitive for the utility than its customers. In fact, the only surety is higher utility earnings. Another negative aspect of UOGR from the perspective of utility customers is that the majority of the cost paid for by customers is likely to be front-loaded while the benefits, if they exist, accrued to them slowly over the later years, at least for a proposed UOGR in Virginia and probably others as well.[140]

B. Overstatement of gas-cost savings

Utilities proposing vertical integration and a long-term commitment usually cite gas-cost savings to customers over time. Yet these savings are extremely small relative to a utility's total purchased-gas costs.[141] Small savings are not surprising given the fact that wholesale gas markets are competitive, with market prices expected to align closely, during most periods, with the cost of producing gas.[142]

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[140] Carsley 2015, 22.

[141] As mentioned earlier the Florida PSC gave approval to a request by the state's largest utility, allowing FPL to invest $191 million in a joint venture with PetroQuest Energy, Inc. The utility estimated small savings for its customers — about $100 million over 30 years or two cents a month for the average 1,000-kilowatt-hour bill. In the WGL proposal, the utility estimated savings of about $84 million over the 20-year term (or on a present value basis a savings of roughly $21 million over the 20 years). This level of savings is miniscule when compared to the total purchased gas costs of the utility. One utility, Questar Gas, estimated gas savings of $1.27 billion from affiliate purchases. Much of this savings occurred during the pre-shale gas period 2000-2008 when natural gas prices spiked because of depleting conventional gas resources. Since 2008, however, Questar Gas has paid more for gas under the Wexpro agreement than on the open market. [McKay 2014.]

[142] Savings over the long term would occur only if the gas field jointly owned by a utility or owned by an affiliate is inframarginal in the sense that it would earn, over time, economic profits from producing gas at a cost less than the market price. One then has to ask why a gas producer would agree to sell gas at its cost of production to the utility instead of at the market price to other buyers. For example, if the market price soared to, say, $20 per Mcf because of severe pipeline constraints, it would be in the financial interest of the utility affiliate or the holding company to redirect gas to the open market away from the utility buyer who, under a joint agreement, would pay a much lower price, say, the cost-of-service price. The same incentive to renege on an agreement would also occur under a long-term contract with an independent entity. There is an apparent contradiction between the alleged savings to utility customers and the rationale for a gas operator to sell gas at its cost of production.

More dubious are predictions of gas prices 10-40 years out, which no one would dispute as being highly speculative. The justification for gas reserve ownership must therefore rest with reasons other than forecasted gas savings over time to utility customers. The following statement by one utility (Black Hills/Colorado Electric Utility Company) seems to capture the thoughts of other utilities proposing vertical arrangements of gas procurement:

> The primary benefit of [our proposed program] is long-term price stability because it narrows the range in gas supply costs. Because the current environment allows market participants to purchase gas reserve interests at favorable prices and drill to make those reserves productive, the [program] would allow the Company to establish a long-term physical hedge against [future] market instability and volatility... A secondary benefit is the reasonably anticipated potential savings for customers over the life of the reserves.[143]

C. Questionable benefits from long-term hedging

Although price stability would normally seem like a benefit, how valuable this would be to utility customers is difficult to quantify and in itself highly speculative. What we have observed in recent years are utilities suffering large losses from even short-term hedging.[144] Analysts and some commissions are questioning whether utilities are over-hedging. While losses are common, when hedging causes large losses constantly over a number of years commissions should ask whether utilities should continue to hedge at the same levels that they have in the past.[145]

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[143] Vancas 2015, 32.

[144] *See*, for example, Carson and Kreilis 2015; and Costello 2011. Losses are essentially calculated as the difference between the hedged price and the prevailing market price times the amount of gas hedged. One conspicuous example is Florida electric utilities together suffering hedging losses of over $6 billion between 2002 and 2015. [Walton December 1, 2015.] Other utilities have losses of hundreds of millions of dollars over time, as well. These losses could have resulted from inflexible hedging strategies, faulty hedging plans, failure to account for extreme events (e.g., lower than recent historical wholesale gas prices), or unexpected events. An inflexible plan, for example, might limit the ability of a utility to mitigate its hedging losses when events turn unfavorably against the utility. An inflexible plan, in other words, makes the utility's hedging less adaptable to changed conditions.

[145] Events since 2008 have raised questions about the future of hedging by utilities. Projections of more stable gas prices should reduce the benefits from hedging. The risk of dramatic increases in wholesale gas costs, except for short periods (e.g., "Black Swans"), appears lower than what it has been for the first half of this century. A Black Swan is a highly improbable event with three distinct characteristics: it is unpredictable; it has a substantial effect; and, after the fact, analysts make the event seem less random, and more predictable, than it was. [Costello 2011.]

Another point is that if the share of gas under a vertical arrangement is so small relative to a utility's total gas needs, simple arithmetic would say that it would have a minimal effect on the average cost of gas.[146] The hedging benefit would therefore seem very small compared with the cost of arranging the agreement and other transaction costs that a utility would incur. It is puzzling that a utility would make all the necessary effort for such a miniscule benefit. One conclusion is that the utility is making these arrangements, as argued earlier, more for its benefit than customers'. Of course this is consistent with a utility acting rationally, but not in the best interest of its customers. Commissions should start with this presumption when evaluating vertical arrangements.

One can even ask whether the vertical arrangements in place and proposed by utilities are pure hedges. They do not guarantee a fixed price or quantity.[147] Even when the transfer price is cost-based, the price charged can change over time, just like utility rates can vary. At best vertical arrangements are a quasi-hedge with questionable benefits to utility customers.[148]

D. Potential for self-dealing abuses

The vertical integration of utilities into gas production also poses the danger of providing an opportunity for a utility or its holding company to evade the reach of rate-of-return (ROR) regulation.[149] If a utility's operations falls under ROR regulation, but no oversight exists over the price the utility pays for gas provided under a joint gas venture, then the utility would be able to achieve the profits denied to it by ROR regulation. The utility could inflate the price charged for its own gas above a competitive level. This would raise the accounting costs to the regulated part of the utility, and permit a higher price to be charged either through a rate redetermination hearing or through an automatic fuel cost adjustment mechanism. These additional "costs" to the regulated operations, however, would be additional profits to the firm's gas operations and the holding company.

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[146] We previously mentioned that most proposed and in-place vertical arrangements for gas procurements involve a small portion of the utility total gas needs.

[147] I want to thank Dr. David Dismukes for this insight.

[148] In fact, in one sense the vertical arrangements proposed by utilities resemble more of a speculative than hedging activity: The utilities are betting that future natural-gas prices will increase based on highly imperfect information, and then structure a long-term plan designed to achieve gas-cost savings. I want to thank one reviewer for this insight.

[149] *See*, for example, Posner 1969.

Potentially, the utility could charge a price for electricity and natural gas, and profit from electricity or natural gas, equivalent to that of an unregulated utility.[150] Commissions would have to be vigilant through monitoring and review of the gas costs under a vertical arrangement to present such an outcome.

E. Imbalanced risk allocation

From the perspective of utility customers vertical integration seems to be a high-risk strategy. Under most proposals and actual plans, utility customers would be shouldering much more risks than utility or holding-company shareholders. Vertical arrangements create several risks. They include: (1) gas-production operating cost, (2) level of gas reserves and production (e.g., "dry holes"), (3) liability and incomplete contractual agreement (leaving room for opportunism or, more generally, bad behavior, (4) counterparty risk, and (5) regulatory-induced risks, derived from less-than-full commission commitment, regulators knowing little about the upstream side of the gas business and having to evaluate complex contract provisions.

The proposals for ownership of gas reserves seem to pose little risk for utilities but allow them to profit from the rate-basing of the investment. Contrast this favorable outcome for the utility with conventional cost recovery of gas costs, where the utility recovers dollar-for-dollar its costs while earning no profit. This is true whether the utility purchases spot-market gas or has a contract with an independent entity. Utility ownership adds another source of profit to the utility. As stated by one utility, ownership of gas reserves allows it an "additional opportunity for capital investment that will earn [a return on equity].[151] Moody's Investors Service describes utility investments in gas reserves as a "new rate base strategy."[152]

After reviewing different vertical-arrangement plans, it seems clear that customer risk is excessive relative to utility or holding company risk. It is somewhat ironic that the major apparent reason for vertical arrangements is to reduce upside price risk to utility customers but, in the process, utilities are asking customers to take on new risks. Although an empirical question, it is conceivable that utility customers could face higher risk from a vertical arrangement that involves UOGR or a utility affiliate than from the absence of long-term

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[150] Structural separation does not eliminate the concern that a utility would have an incentive to engage in self-dealing abuses. Consequently, behavioral rules (e.g., standard-of-conduct rules) would need to accompany a structural-separation mandate. The social benefits from structural separation partially rest on the degree of economies of scope between the regulated and the unregulated lines of business.

[151] Washington Gas Light Company 2015, slide 10.

[152] As remarked by Moody's Investor Service (2015, 6), "[A]s a rate base asset, the costs for gas reserves earn utilities a margin and contribute a cash flow stream that incrementally boosts key financial metrics, such as cash flow from operations (CFO) to debt."

hedging. A review of the vertical arrangement plans suggests that customers could very well bear higher risk from an action that purports to protect those same customers from risk.

F. Disputable role of vertical arrangements in a robust gas market

A final point is that liquid wholesale gas markets (which minimize gas supply risk[153]) plus highly speculative forecasts of long-term gas prices severely weaken the case for utility ownership of gas reserves or other vertical arrangements. A long-term commitment to buying natural gas from a particular source at a specific price (or range of prices) seems incompatible with an industry that has been successful over the past 25 years in moving away from long-term contracts to short-term spot and other transactions. These transactions have greatly benefited gas customers and have taken place in a well-functioning marketplace. As predicted by TCE, vertical arrangements are less defensible when the market for a product or service is competitive and well-functioning.

VIII. Advice to Regulators

Throughout the history of regulation, regulators have expressed their skepticism toward vertical arrangements. There are good reasons for this and vertical integration of gas procurement should pose no lesser concerns. Utilities should have a strong burden of proof that gas-reserves ownership and other vertical arrangements benefit their customers in the long term (if they are able to do that). Although it is clear how these arrangements can mutually benefit utilities, their affiliate, and utility holding companies, the benefits to utility customers are less obvious.

A. How much do utility customers benefit from long-term hedging?

Utilities proposing vertical arrangements are implicitly assigning a high value to long-term hedging. This value may not reflect customers' perception of benefits. The large hedging losses experienced by utilities in recent years suggest that they should consider cutting back on hedging, rather than expanding their hedging on a long-term basis. Yet, the ultimate question is how long-term hedging fit into a utility's gas-procurement portfolio.

In evaluating proposals for vertical arrangements, regulators should have some understanding of the value that utility customers place on stable prices. Hedging is not a costless activity, so the utility should provide evidence, other than conjecture, that customers are willing to pay something for more stable prices over the long term. The vertical arrangements discussed in this paper are all complex, involving substantial utility costs in

[153] In general, natural gas supply and demand would equilibrate at an appropriate price to balance the two. A higher price that results, for example, from increased demand is an example of price risk, not supply risk.

negotiating, executing, and enforcing and monitoring. Regulators should determine, as best they can, that these costs are justifiable from the perspective of utility customers.

Regulators should therefore ask themselves three questions about long-term hedging, which after consideration of everything comes down to the most legitimate reason for vertical arrangements. First, what are the benefits and costs to customers from stable prices over several years or even decades? Second, is the current time ripe for long-term hedging? Third, what specific market and other conditions would make long-term hedging beneficial to utility customers?[154]

B. Are vertical arrangements in the public interest?

1. Regulators beware

Regulators should therefore beware of long-term arrangements and give them close scrutiny when proposed by utilities. They should try to determine the specific conditions that might legitimize a utility's involvement with the gas production business. Even if regulators conclude that long-term hedging is appropriate, it should then ask whether a vertical arrangement with an affiliated or independent gas operator is the best approach.

One conclusion reached in this paper is that the typical reasons for companies to vertically integrate do not seem to hold for utilities in their procurement of natural gas. Gas production is not highly asset specific, for example, as the facilities to produce gas can easily shift from dedicated sales to a single customer to sales in the open market, assuming the availability of transportation capability. Vertical integration or even long-term contracting is therefore not necessary to protect the producer from hold-up or opportunism by gas buyers.[155] As noted in one study describing the market environment post-open access in the natural gas industry:

> [A gas] field served by two or more pipelines has access to a large number of buyers through each pipeline system. Thus, the gas field investment is no longer transaction-specific capital, and there is no longer any need for long-term sales contracts…[156]

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[154] While most state utility commissions have not expressed any policy on long-term hedging, a few have endorsed it based on their decisions for utility proposals and more general consideration. These states include Colorado, Florida, Louisiana, Montana, Oklahoma, Oregon, Utah and Wyoming. *See* Louisiana Public Service Commission 2015, and the earlier discussion in this paper.

[155] Opportunism arises if, for example, a gas producer faces few buyers at the time of contract renewal, so that the buyers have bargaining power with the producer.

[156] Doane and Spulber 1994, 504.

The introduction of a new business function for utilities should raise two "red flags" for regulators: (1) the potential for cross subsidization and cost shifting;[157] and (2) the dilution of managerial attention. The social benefits from vertical integration, as outlined in the economics literature, seem unlikely for gas procurement by utilities. Vertical integration by electric utilities with coal mines, for example, is consistent with TCE because of asset specificity that makes contracting with an independent entity highly complex and costly.[158] The same rationale and others identified by TCE seem irrelevant to utilities procuring natural gas.

To protect their interest in a vertical arrangement, utilities need to be vigilant in monitoring their gas-operator partner. Effective utility management in contracting or non-operating ownership includes evaluating and selecting a supplier, and negotiating, executing and administrating contractual agreements. According to one study,

> Passive investing in unconventional plays is not a route to success; rather, utilities that choose to have others operate must at a minimum ensure that operators are meeting manufacturing learning targets. Otherwise, costs and production will not be competitive, and "the prize" of reserves ownership will not be captured.[159]

2. Dubious overall benefits to utility customers

The most plausible explanation for vertical arrangements seems to be that the holding company composed of both the utility and the E&P affiliate, or just the utility itself, is the largest beneficiary with utility customers bearing most of the risk. Besides, even if a vertical arrangement is tenable, regulators may want to require utilities to structure their E&P affiliate as a separate entity with zero funding from utility customers. What we have learned across a wide range of industries is that, more times than not, when companies, including utilities, expand their business activities outside their core corporate skills and culture, failure ensues. Customers should not have to bear the costs of unsuccessful utility endeavors in peripheral business lines, especially since the open market has demonstrated for the past 30 years its ability to satisfy the needs of electric and gas utilities.

C. Rebuttable presumption in favor of market transactions

Regulators should start with the premise that long-term contracting with an independent gas producer or marketer would be preferable. Utilities have argued that such contracting is generally unavailable, as gas producers are just not interested in making a long-

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[157] For example, in a monopoly market where the utility can pass through higher prices with little effect on demand, the utility would have greater ability to engage in cost-shifting and other abuses.

[158] *See*, for example, Joskow 1985 and 1987.

[159] BRG Energy 2015, 7.

term commitment. Yet, if these entities see such arrangements as not financially attractive, why then would a utility-affiliated gas producer see things differently, especially when it is willing to sell gas to the utility at cost of service? Just like independent gas producers, affiliated producers would lose "profit" opportunities when the market price rises. After all most of the utilities proposing vertical arrangements have argued that the market price of gas should increase in the future.

Finally, regulators will likely see more vertical arrangements in the near term as gas producers will continue to endure financial stress if gas prices remain low and utilities and their holding companies try to grow their earnings. Whether regulators should approve vertical arrangements hinges largely on the value they assign to long-term hedging in the confines of utilities' gas-procurement portfolios.

Appendix: Questions for Commissions on Vertical Arrangements

Regulatory policy

1. Has regulation unduly discouraged utilities from making long-term commitments for gas procurement? If so, is this a problem that warrants a commission's attention?

2. Have a commission's actions, for example, led to an excess of short-term transactions for gas procurement?

3. Does the commission have a policy or guidelines on long-term gas procurement?

   a. Would utilities make long-term commitments only when commissions pre-approve contracts and other agreements or, at the minimum, establish firm guidelines for cost recovery?

   b. How much certainty should commissions give utilities over approval of long-term utility commitments and the associated costs? What are the implications of commission preapproval of a long-term commitment for cost recovery?

4. What should be the commission policy on vertical arrangements for gas procurement?

5. How should commissions evaluate long-term vertical arrangements relative to contracting with an independent entity? What are the benefits and costs of each alternative?

6. How do a commission's practices and policies (including authorization of the use of gas cost-recovery mechanisms) affect incentives for different commercial structures such as spot purchases, vertical integration and long-term contracts with an independent entity?

7. Should long-term gas procurement be competitively bid? If so, how should the utility structure and execute the bidding?

8. What oversight should a commission maintain over the life of a long-term agreement for gas procurement?

Economic consideration

1. What factors have most contributed to the trend over the past 30 years of shorter-term natural gas transactions? Do current conditions support a reversal of this trend and longer-term transactions?

2. What is the role of long-term agreements in a utility's gas-procurement portfolio? Can long-term contracts or vertical arrangements complement other kinds of commercial transactions to achieve an "optimal" portfolio?

3. What are the risks (and benefits) to a utility from a vertical arrangement for gas procurement?

4. What risks do utility customers bear under a vertical arrangement?

5. What potential benefits do utility customers receive?

5. Do the expected benefits from a vertical arrangement for utility customers compensate for the risks that they bear?

6. What are the special concerns with a long-term agreement (a) between a utility and an affiliate, and (b) when the utility owns gas reserves?

Specific contractual/joint venture provisions

1. What are the different price and non-price terms and conditions in a typical long-term contractual or joint venture arrangement?

2. What factors affect the appropriate duration of a long-term agreement?

3. On what basis does (or should) the contracted price change over time? How was the base price or price term determined?

4. How did the utility evaluate a vertical arrangement for gas procurement relative to other options, such as long-term contracting with an independent entity and financial hedging?

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BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 308

In the Matter of	)
	)
PORTLAND GENERAL ELECTRIC COMPANY,	)
	)
	)
2017 Annual Power Cost Update Tariff.	)
	)

CONFIDENTIAL EXHIBIT ICNU/203

COMPANY RESPONSES TO ICNU DATA REQUESTS

August 12, 2016

(REDACTED VERSION)

June 10, 2016

TO: Tyler Pepple
Bradley Van Cleve
Davison Van Cleve, P.C.

FROM: Patrick Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 308
PGE Response to ICNU DR No. 013
Dated June 7, 2016

Request:

Please provide a copy of any and all documentation or manuals concerning the Company's current hedging policies, procedures, and practices.

Response:

PGE objects to this request on the grounds that it is overly broad and unduly burdensome. Subject to and without waiving its objection, PGE responds as follows:

See Section 6 of Attachment 013-A for PGE's current policies and procedures governing PGE's hedging practices for power supply.

Attachment 013-A is protected information subject to Protective Order No. 16-137.

Pages 2 – 4 of Exhibit ICNU/203 contain Protected Information subject to Protective Order No. 16-137 and have been redacted in their entirety.

July 14, 2016

TO: Tyler Pepple
Bradley Van Cleve
Davison Van Cleve, P.C.

FROM: Patrick Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 308
PGE Response to ICNU DR No. 021
Dated June 30, 2016

Request:

Based on Figure 1 in PGE/100 at 8, ICNU understands that, if the Company goes forward with a long-term hedging strategy, it will be incremental to its existing mid-term strategy, meaning that approximately 60% of PGE's gas costs will be hedged five years out or longer.

a. Please confirm or clarify this understanding; and

b. Assuming ICNU's assumption is correct, has PGE considered reducing the scope of its mid-term strategy if it implements a long-term hedging strategy? Please explain.

Response:

a. PGE confirms this understanding in accordance with PGE Exhibit 100, pages 7-8.
b. PGE continually evaluates its hedging strategy and would consider reducing the scope of its mid-term strategy, if it is beneficial for customers to do so.

DAVISON VAN CLEVE