BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UM 1286

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In the Matter of	)
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THE PUBLIC UTILITY COMMISSION	)
OF OREGON,	)
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Investigation into the Purchased Gas	)
Adjustment (PGA) Mechanism Used by	)
Oregon's Three Local Distribution	)
Companies.	)
	)

OPENING COMMENTS

OF THE

CITIZENS' UTILITY BOARD OF OREGON

December 4, 2007

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UM 1286

In the Matter of THE PUBLIC UTILITY COMMISSION OF OREGON, Investigation into the Purchased Gas Adjustment (PGA) Mechanism Used by Oregon's Three Local Distribution Companies.	OPENING COMMENTS OF THE CITIZENS' UTILITY BOARD OF OREGON

I. Introduction

This docket was opened to examine the current PGA mechanisms used by Oregon's natural gas utilities. Though the current mechanisms appear to be working reasonably well, we take this opportunity to propose updates to Oregon's purchased gas adjustment (PGA) mechanisms to reflect concerns we have regarding the distribution of risk within the mechanisms. Currently, the gas utilities are not expected to manage the normal risks and rewards of utility business, as the very first dollar of gas cost variation is shared – in Avista's case, 80% – with customers. This does not reflect the Commission's current approach to normal utility business risk that has been addressed recently for electric utilities, but which applies equally to gas utilities. On the other hand, customers, with their wide financial base, are in a better position to absorb extreme power cost variations, and it may be appropriate to ask customers to bear more of this risk.

Our proposal attempts to modify mechanisms that are functioning reasonably well, by adjusting the distribution of risk within the mechanisms to better reflect which entity, shareholders or customers, is better able to manage the risk in question. Though a deadband is new to an Oregon PCA mechanism, it is a well-established measure of normal business risk that has been used for electric utilities for years, and we do not see it as a radical departure from the current Oregon regulation. Obviously, we seek to propose a mechanism that will function over time, and that will be flexible with changing natural gas and capital markets. We also seek to address the Commission's concern that an ongoing mechanism, such as the PGA, be revenue-neutral over time.

We propose a single PGA mechanism, as we agree with the Commission's 1989 conclusion that "[t]here is no strong evidence that a generic tariff approach is flawed."[1] Indeed, in the use of a deadband calculated using a dollar value equivalent to basis points of a utility's return on equity, we seek a mechanism that would be proportional both within a changing utility, as well as proportional between utilities. Over the years, the PGA mechanisms for Avista, Cascade, and NW Natural have diverged both through utility election, and through individual tweaks for various reasons. This docket presents a good opportunity to look at an overall PGA mechanism to serve all three of Oregon's natural gas utilities. The utilities, obviously, are not identical, and adjustments may be necessary, but starting from the same foundation would make for more transparent and rational regulatory policy.

[1] UG 73 OPUC Order No. 89-1046 at 12.

II. The Current PGA Mechanisms

The current PGA mechanisms have performed reasonably well based on a cursory examination of Energy Information Administration (EIA) gas cost data and NW Natural's credit ratings. However, Staff initiated a prudence review of Avista's gas purchasing strategy in UM 1282, on the basis that the Company was over-hedging its portfolio in reaction to the PGA mechanism in order to shield its shareholders from the risk of gas-price volatility.[2] This was not Staff's first mention of its concern regarding Avista's hedging practices in particular,[3] and the gas utilities' hedging practices in general.[4] Though over-hedging in reaction to a regulatory mechanism is an issue of prudence, and not necessarily one of mechanism design, this docket was opened to examine the current gas utilities' PGA mechanisms, and propose changes or replacement as appropriate.

A. The Framework Of The Current PGA Mechanisms

Using very broad brushstrokes, Cascade and NW Natural have PGA mechanisms that pass through to customers 100% of their fixed costs and commodity-related costs incurred up to the date of the utilities' Fall PGA filing. After the Fall PGA filing, these utilities have a risk-reward sharing mechanism for commodity-related cost differences between the forecasted costs and the actual commodity-related costs of 67-33 (customer-utility).[5] As a result of the utilities sharing 33% of these commodity-related cost

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[2] Zimmerman, Ken; Kittilson, Lynn; Owings, Carla. OPUC Staff Memo to Commission, Subject: Avista Utilities, October 18, 2006 at 10.
[3] Zimmerman, Ken; Kittilson, Lynn; Owings, Carla. OPUC Staff Memo to Commission, Subject: Avista Utilities, September 19, 2005 at 11-12.
[4] OPUC Staff. Proposed Agreements Relating to the Oregon PGA Mechanism - Draft 4/7/2006 at 2.
[5] OPUC Order 99-272 at 2, footnote 1.

differences, they are not subject to a Fall earnings review.[6] Avista continues to use a risk-reward sharing mechanism for commodity-related cost differences of 80-20 (customer-utility) from Commission Order 89-1047. As a result, Avista is subject to a Fall earnings review. All three of the gas utilities are subject to a Spring earnings review.[7]

B. The Current PGA Mechanisms Have Performed Reasonably Well

Evaluating a regulatory mechanism that has, in varying forms, been in place for decades could provide topics for more than one dissertation. With that in mind, we started our examination of the current PGA mechanisms with a simple gut check. While no regulatory structure will ever be perfect, the current PGA mechanisms have served for a number of years without any major crises. Certainly, Staff has raised the issue of whether a different incentive mechanism might reduce utility over-hedging.[8] Both Avista and NW Natural have recently complained that the current mechanisms subject shareholders to too much risk.[9] However, from an overall perspective, the gas utilities' current PGA mechanisms appear to be working, and not to be critically flawed.

As a simple external check to our gut reaction, we looked at EIA natural gas price data to evaluate the prices Oregon customers pay as compared to what customers in other states pay. We also looked at NW Natural's current credit rating to see if the capital markets find a gas-only Oregon utility to be a particularly risky venture. While credit ratings involve any number of factors, it seems reasonable to presume that an

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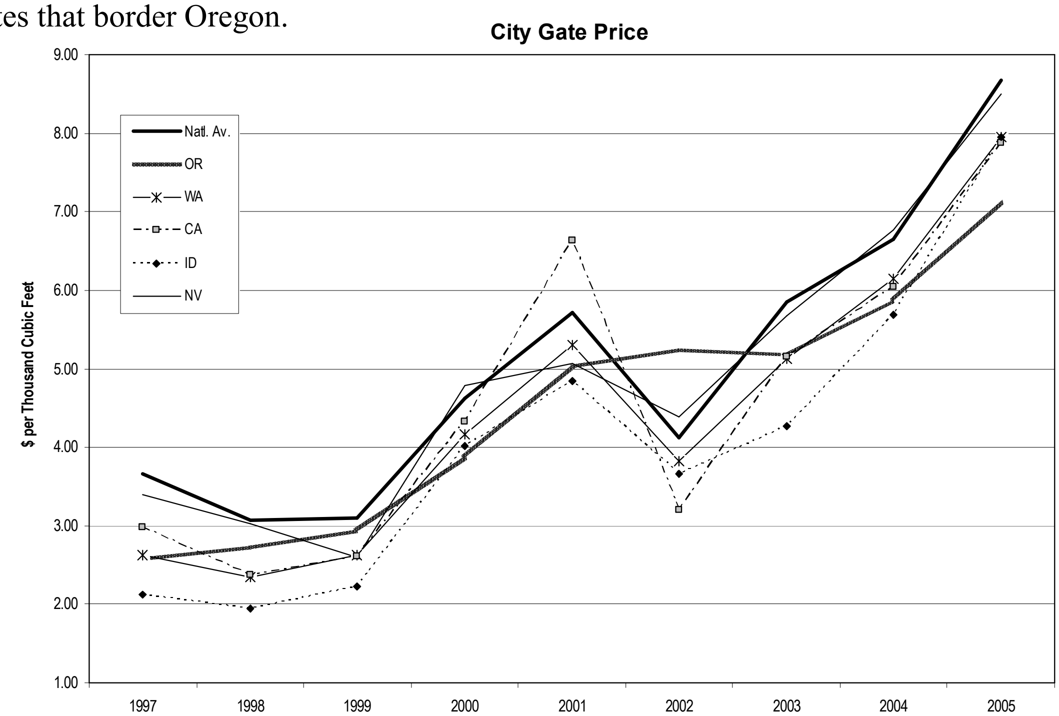
[6] OAR 860-022-0070 (8).
[7] UM 903 OPUC Order No. 99-272 Appendix A at 1-2.
[8] OPUC Staff. Proposed Agreements Relating to the Oregon PGA Mechanism - Draft 4/7/2006 at 2.
[9] UM 1282 Stipulating Parties/100/Zimmerman-Thackston-Pyron/1 & NW Natural Advice 07-6 Letter to Commission, October 22, 2007 at 1.

extraordinarily risky regulatory mechanism would be reflected in NW Natural's credit rating.

i. From The Customer Perspective – EIA Data

In order to examine how Oregon's current PGA mechanisms are operating, we looked at Energy Information Administration (EIA) data to compare various states' city gate, residential, commercial, and industrial natural gas prices. Recognizing that there are regional differences in the cost of natural gas, such as transportation, we considered mostly western states. We considered the 9 most-recent, complete annual data sets (1997-2005) for Oregon, Washington, California, Idaho, Montana, Nevada, Utah, Oklahoma, and the national average.[10] The following graph shows that Oregon's city gate natural gas prices were lower than the national average in every year except 2002. Also included in the chart are Washington, California, Idaho, and Nevada, the states that border Oregon.



[10] Though 9 years is an odd period of time to use, 1997 is the first year for which annual EIA data is available for industrial customers, and 2005 is the last year with relatively complete EIA annual data in general.

On average, from 1997 through 2005, Oregon's city gate price[11] – which reflects the commodity cost incurred by Oregon's utilities – was right in the middle of the pack, while, when 2002 data is removed, Oregon's city gate price was lower than all but those in Idaho and Montana, which are closer to gas supply and may have lower transportation costs.

Interestingly, the rates paid by Oregon's natural gas customers have not compared as favorably to the national average. In particular, the following table shows that average residential rates from 1997 through 2005 were higher than both the national average and every other state we looked at. The table also shows these averages, but with 2002 removed, because, as can be seen from the previous chart, 2002 appears to be an anomalous year for Oregon. The highlighted cells are prices that are below Oregon's.

Average Natural Gas Price in $ per Thousand Cubic Feet

	City Gate		Residential		Commercial		Industrial	
	1997 - 2005	'97-'05 w/o 2002	1997 - 2005	'97-'05 w/o 2002	1997 - 2005	'97-'05 w/o 2002	1997 - 2005	'97-'05 w/o 2002
National Average	5.05	5.17	**8.77**	**8.88**	7.52	7.63	**4.95**	**5.07**
Oregon	*4.51*	*4.42*	*9.15*	*8.98*	*7.29*	*7.21*	*5.40*	*5.21*
Washington	**4.46**	4.54	**8.20**	**8.06**	**7.16**	**7.03**	**5.18**	5.22
California	4.58	4.75	**8.55**	**8.73**	7.70	7.90	5.89	6.01
Idaho	**4.08**	**4.14**	**7.36**	**7.23**	**6.65**	**6.51**	**5.31**	**5.11**
Montana	**4.19**	**4.35**	**6.78**	**6.97**	**6.74**	**6.91**	**5.25**	5.56
Nevada	4.91	4.97	**8.59**	**8.45**	**7.19**	**7.12**	7.13	7.06
Utah	**4.48**	4.54	**6.88**	**6.94**	**5.58**	**5.63**	**4.43**	**4.50**
Oklahoma	4.83	4.90	**8.18**	**8.23**	7.41	7.47	6.26	6.26

While Oregon's rates are generally higher than other western states, in most cases, this does not appear to be due to higher gas commodity costs. Customers and regulators

[11] The EIA glossary defines "Citygate" as: A point or measuring station at which a distributing gas utility receives gas from a natural gas pipeline company or transmission system.

should be concerned about the prices paid by Oregon customers, however, the city gate prices indicate that this is not caused by the gas utilities' commodity costs incurred under Oregon's risk-reward sharing structure.

ii. From The Company Perspective – Credit Ratings

Of the three gas utilities in Oregon, NW Natural's credit rating would be the most likely to show an indication of a strong rating concern over Oregon's regulatory mechanism for addressing the Company's gas cost recovery. This is because NW Natural supplies only natural gas and serves primarily Oregon customers. From NW Natural's latest quarterly report to the Securities and Exchange Commission, it can be seen that NW Natural does not appear to be a particularly risky investment from the credit rating agencies' perspective.

NW Natural 10-Q
For the quarterly period ended September 30, 2007

	S&P	Moody's
Commercial paper (short-term debt)	A-1+	P-1
Senior secured (long-term debt)	AA-	A2
Senior unsecured (long-term debt)	A+	A3
Ratings outlook	Stable	Positive

While this hardly represents an exhaustive analysis, it does serve as a simple indication that Oregon's current PGA mechanism for NW Natural is not considered to be an enormous liability by the credit rating industry.

C. Weaknesses Of The Current PGA Mechanisms

In a nutshell, the weakness of the current PGA mechanisms that we try to address in our proposed mechanism is the current mechanisms' distribution of risk and reward within the mechanisms. More specifically, the current mechanisms fail to account for the normal risks and rewards of the utility business, and they fail to adequately account for the fact that extraordinary events may place too great a risk on the utility.

Generally, it is reasonable for customers to know the price of gas before they buy it, and to expect utilities to manage the normal variability of costs that are inherent in utility – indeed in any – business. Extreme gas cost spikes that are outside of the normal range of variability, however, can weaken a utility's financial integrity; and customers, with their wide financial base, are in a better position to absorb these large cost variances. In discussing CUB's proposed mechanism, we will point out how the current PGA mechanism could be changed to better place costs and risks on the entity best able to manage and/or absorb those costs and risks.

D. Removing Risk-Reward Sharing Won't Remove Need For Prudence Reviews

As mentioned earlier, Staff is concerned that the risk-reward sharing component of the current PGA mechanisms provides an incentive for the gas utilities to over-hedge, such that most of their gas supply is locked-in before the PGA filing.[12] Dependent upon a utility's willingness to take risk for reward, Staff's concern would only be true for a utility whose risk-aversion led it to imprudently over-hedge. On the other end of the spectrum would be a utility whose risk-inclination led it to imprudently under-hedge for the lure of the potential reward. In either case, customers rely on regulatory prudence reviews to ensure that utilities procure gas in a manner that seeks to balance the often competing goals of low-cost and low-risk. This dynamic will exist whether the risk-reward sharing ratio is 67-33 or 80-20.

[12] Zimmerman, Ken; Kittilson, Lynn; Owings, Carla. OPUC Staff Memo to Commission, Subject: Avista Utilities, October 18, 2006 at 10.

The solution proposed by Staff in its draft proposed agreements of 2006 was to remove the risk-reward sharing mechanism, and pass through 100% of gas commodity costs to customers.[13] Through this change, neither the risk-averse nor the risk-inclined utility would have an incentive to hedge imprudently, as shareholders would be completely insulated from gas commodity costs. Not surprisingly, this comes with a tradeoff. Shareholders and utility managers, who would now be completely insulated from gas commodity costs, wouldn't have a personal stake in gas commodity costs. In abandoning risk-reward sharing, the Commission would be removing the alignment of customer and shareholder interest in keeping gas costs low. Under this proposal, too, customers would have to rely on regulatory prudence reviews to ensure that utilities procure gas in a prudent manner, despite their lack of a personal stake in gas costs.

Regardless of whether the PGA mechanism contains risk-reward sharing or not, prudence reviews will be an important component of customer protection. In choosing a PGA mechanism that passes 100% of gas commodity costs through to customers, the Commission would not be removing the need for prudence reviews, it would only be shifting the focus of prudence reviews from monitoring for one kind of imprudent behavior to monitoring for another. We propose a risk-reward sharing mechanism, not a 100% pass-through, and would point out here, that a straight pass-though mechanism relieves neither the utilities of their obligation to prudently manage gas costs, nor Staff and customers of their obligation to monitor utilities' actions.

[13] OPUC Staff. Proposed Agreements Relating to the Oregon PGA Mechanism - Draft 4/7/2006 at 2.

III. CUB's Proposed Mechanism

CUB proposes the following PGA mechanism for all gas cost variations after the utilities' PGA filing:

Earnings Deadband	±100 basis points ROE
Gas Cost Deadband	-75 to +150 basis points ROE for gas utilities not subject to SB 408 -45 to + 90 basis points ROE for gas utilities subject to SB 408
Gas Cost Sharing	90-10 (customer-utility)

A. Commonalities & Differences of the Gas and Electric Utility Industries

Gas utilities, like electric utilities, provide a critical public service which requires a great deal of capital investment, on behalf of customers, in infrastructure. Both electric and natural gas utilities are allowed to earn a rate of return for their investment in infrastructure, and have rates that are regulated by the Commission, rates which are designed to provide an opportunity for the utilities to recover their costs and earn a return on their investments. Both gas and electric utilities face normal business risks, and also face the risk that their established rates might not fully cover their costs or allow for a reasonable return. This basic utility structure is the same for gas and electric utilities.

That being said, natural gas utilities and electric utilities have their differences, as well. Natural gas can be directly stored, electricity cannot (though an electric utility can store fuel for its generating plants or use pumped storage). On the other hand, gas utilities can only supply natural gas with … natural gas. Electric utilities can supply electricity from dams, coal plants, wind plants, natural gas plants, and other generating options. This gives electric utilities a wider margin in managing their resources than gas utilities have. With this in mind, our proposed mechanism contains a smaller deadband than what the Commission found to be appropriate for PGE.

B. The Earnings Deadband

An earnings check has long been an integral part of the gas utilities' PGA mechanisms. Since 1989, in its orders modifying the gas utilities' PGA mechanisms, the Commission has affirmed the nexus between an earnings review and the gas adjustment mechanism.

> One of the primary issues in this proceeding is to review the purchased gas adjustment (PGA) risk-reward sharing mechanism and the structure of related earnings reviews.

UM 903 OPUC Order No. 98-543 at 1.

> The primary issues for review include the appropriate structure of the risk-reward sharing incentive mechanism for gas cost differences and the role and structure of earnings reviews.

UM 903 OPUC Order No. 99-272 at 1.

More recently, in the process of developing an automatic adjustment clause for PGE's power cost variations, the Commission included the concept of an earnings deadband in its list of components that it considers crucial to a power cost adjustment: "No Adjustments if Overall Earnings are Reasonable."[14] The Commission's rationale for proposing an earnings deadband for a power cost adjustment mechanism was that the earnings deadband would act as a reasonableness check, such that money would not be shifted between customers and shareholders when the utility's earnings were within a reasonable range.

> First, the Commission will apply an earnings test to determine whether the utility is earning an acceptable rate of return. An earnings test serves to protect customers from paying for higher-than-expected power costs when the utility's earnings are reasonable, while it protects the Company from refunding power cost savings when it is underearning.

UE 180 OPUC Order No. 07-015 at 26.

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[14] UE 165 OPUC Order No. 05-1261 at 8.

The earnings deadband monitors the reasonableness of rates, and, thereby, also minimizes unnecessary rate changes. Only when PGE's earnings are outside of a reasonable range will it be necessary to address power cost variations. In such a circumstance, should PGE's power cost variation be outside of the normal range, then 90% of the power cost variation beyond the deadband will be shared with customers to the extent that the sharing brings the utility into a reasonable range of earnings.

In addition, the earnings deadband proposed by the Commission in UE 165 and instituted in UE 180 is calculated using 100 basis points of a utility's return on equity. This has the benefit of ensuring that the earnings deadband remains proportional as the utility's capital structure and rate base change. We propose the same earnings band in this case, noting that the use of 100 basis points maintains proportionality not only within an individual utility, but also across utilities.

Finally, while an earnings check is an important component of an automatic adjustment clause for an electric utility, it is even more important for gas utility automatic adjustment mechanisms. This is because natural gas utilities tend to file fewer rate cases than electric utilities do. Gas utilities have PGA mechanisms that pass through to customers most of the annual change in gas costs, they have line extension policies that do not require expanding to serve new customers if such an expansion would not be profitable, and gas utilities have less need for rate cases to bring large capital projects into rate base. A gas utility can go a decade without a rate case, and, therefore, it is extremely important that the annual PGA process provides a check to ensure that rates remain just and reasonable in the absence of a general rate case.

C. The Relationship Between The Deadband & The Sharing Percentage

As mentioned earlier, though we think the current PGA mechanisms are working as intended, one of our concerns with the current mechanisms is that the placement of risk within the mechanisms does not reflect which entity, the utility or customers, is better able to handle which risks. The current mechanisms put more of the burden of normal cost variations on customers, who have no control over them; and put more of the burden of extraordinary cost variations on the Company, when customers are in a better position to handle that burden. Our proposed mechanism shifts more of the risk of normal business variability to the utility, but more of the risk of significant cost excursions onto customers.

i. The Deadband Represents The Normal Risks & Rewards Of Business

In sharing the first dollar of post-PGA filing, gas cost variation, the current PGA mechanisms fail to recognize the inherent business risk that utilities are expected to, and paid a rate of return to, manage. The Commission has addressed this normal business risk recently in a number of dockets:

> We allowed no recovery of costs or refunds to customers within [the UM 995] deadband, reasoning that the band represented risks assumed, or rewards gained, in the course of the utility business.

UM 1071 OPUC Order No. 04-108 at 9.

> We conclude that a [power cost adjustment mechanism] should be adopted to capture power cost variations that exceed those considered part of normal business risk. In this case, normal business risk for PGE includes all of the circumstances to which it is exposed such as hydro variability.

UE 180 OPUC Order No. 07-015 at 26. Footnote omitted.

It is the gas utility that is in the position to manage gas commodity costs, and the utility shareholders should be subject to the normal risks and rewards of the utility business. In sharing the first dollar of gas cost variation, the current PGA mechanisms do not recognize a normal risk-reward range of commodity costs that the utility is responsible for managing. The addition of a deadband to the PGA mechanisms would remedy this problem by putting the responsibility for normal business variability on the shoulders of the entity in the position to manage it, the utility.

ii. The Utilities Have Teams Of Experts To Manage Gas Commodity Costs

While there is certainly debate about the extent to which natural gas utilities can manage their gas commodity costs, we have yet to be convinced that the utilities are completely at the mercy of the gas market. As the gas utilities maintain a staff of gas-procurement and risk-management experts, we can only conclude that the utilities too think they have the ability to manage gas commodity costs. If the gas utilities believed that they didn't have any ability to manage gas costs, why, then, would they pay a team of people whose job it is to manage gas costs? In addition, Staff has expressed its opinion that the utilities' experts need to be proactively monitoring and managing their gas portfolios.

> While it is true that LDCs have fewer options for controlling gas price than they had in the past and that natural gas is in crisis, it is false that LDCs are wholly at the mercy of the gas market … It will require that [the utilities] more directly and actively 'manage' [their] gas supply cost on a monthly and sometimes even daily basis, especially during the peak winter period.

Zimmerman, Ken; Kittilson, Lynn; Owings, Carla. OPUC Staff Memos to the Commission, September 19, 2005, Avista at 9-10, Cascade at 9, and NW Natural at 10.

> 2. While the current natural gas market arrangements do limit the options of LDCs in controlling the level and volatility of the price paid for natural gas, portfolio purchasing provides an array of tools to retain at least some LDC control over these pricing concerns …
>
> 4. Purchasing natural gas via the portfolio approach requires more attention and effort by the LDC to gather, review, interpret, and apply

> market intelligence in constructing the portfolio; in monitoring the actual functioning of the portfolio constructed; and in modifying the portfolio as market or operational changes require …

Zimmerman, Ken; Kittilson, Lynn; Owings, Carla. OPUC Staff Memo to Commission, Subject: Avista Utilities, October 18, 2006 at 7.

Even if we play the devil's advocate, and presume that gas utilities have no control whatsoever over gas commodity costs, a deadband is still an important component of an automatic adjustment clause that accounts for normal business variability. In UE 165, the Commission states that "hydro availability is largely beyond the company's control."[15] Nevertheless, the Commission maintains that, in an overall power cost adjustment mechanism, hydro variability is a component of the risk an electric utility is expected to manage in the normal course of business.

> In this case, normal business risk for PGE includes all of the circumstances to which it is exposed such as hydro variability.

UE 180 OPUC Order No. 07-015 at 26.

Though we think – and the utilities appear to think, and Staff also thinks – that the gas utilities have an ability and responsibility to manage gas commodity costs, the utilities are expected to manage the normal risks and rewards of the utility business, and this includes managing circumstances that are outside of the utility's control, but within which the utility is expected to operate.

iii. The Importance Of Revenue Neutrality & An Asymmetric Gas Cost Deadband

In UE 165, the Commission discusses the importance of revenue neutrality in an ongoing cost recovery mechanism, and notes CUB's argument that an asymmetric deadband is necessary to achieve this.[16] In UE 180, the Commission established an

[15] UE 165 OPUC Order No. 05-1261 at 9.
[16] UE 165 OPUC Order No. 05-1261 at 8 and 10.

asymmetric deadband for PGE to ensure that the power cost adjustment mechanism was revenue neutral over time.[17] Not wishing to belabor the point, we will simply point out, that, as with electric power prices, when the price of natural gas rises, there is no upper bound, but that the savings from low natural gas prices is constrained.

A deadband must be asymmetric to recognize the asymmetry of the magnitudes of risk on either side of forecast natural gas costs. When the weather is cold and gas supplies are short, the price for gas can increase quickly. However, when the weather is warm and gas supply is plentiful, gas prices can drop – theoretically – only as far as zero. Thus, to ensure that an ongoing PGA mechanism is revenue neutral between customers and shareholders, the deadband for high natural gas costs must be larger than the deadband for low gas costs in order to balance the magnitude of costs recovered and refunded over time.

iv. The Magnitude Of The Deadband

As discussed earlier, a flaw in Oregon's current PGA mechanisms is the lack of a deadband which reflects normal business risk. It is the utility that is in a position to manage the normal variability between forecast and actual costs. Below, we discuss customers' ability to absorb significant cost excursions. These are both general concepts, but, for regulatory purposes, a line needs to be drawn between normal business variability and significant cost excursions.

For electric utilities, through a series of power cost deferrals and power cost adjustment dockets, 250 basis points of ROE has come to represent the normal power cost variation that a utility is expected to manage. This was prior to SB 408. As SB 408 removes the utility's ability to benefit from the tax deduction associated with losses, a

[17] UE 180 OPUC Order No. 07-015 at 26.

deadband adjusted for the utility's effective tax rate is appropriate to represent the same normal business risk for a utility subject to SB 408. To create a revenue-neutral mechanism, the lower end of a power cost adjustment mechanism for an electric utility not subject to SB 408 would be -150 basis points of ROE. As PGE is subject to SB 408, the deadband around its power costs is from -75 basis points ROE to +150 basis points.[18]

Natural gas utilities have smaller rate bases than electric utilities. Thus a deadband calculated from basis points of ROE would result in a smaller dollar amount for a gas utility than an electric one, and so would remain proportional between electric and gas utilities. However, in recognition of some of the fundamental differences between the electric and gas industries – most notably the number of tools with which an electric utility can manage its power supply costs – we propose a smaller deadband for the PGA mechanism. See Section III.A for this discussion.

We propose, for a gas cost deadband, using -75 to +150 basis points of return on equity for a gas utility that is NOT subject to SB 408.[19] Based upon our experience with the electric and gas utilities in Oregon, -75 to +150 seems to be a reasonable number for a gas utility not subject to SB 408. For gas utilities subject to SB 408, we propose adjusting this deadband by an approximate effective tax rate of 40%, resulting in a gas cost deadband of -45 to +90 basis points of ROE.

v. Sharing Percentage For Major Cost Excursions

This brings us back to the relationship between the deadband and the sharing percentages. In our proposed mechanism, we advocate shifting, to the utilities, the

[18] UE 180 OPUC Order No. 07-015 at 26. (original deadband) x (1 - effective tax rate) = SB 408 deadband. In PGE's case: 250 x (1- 0.4) = 150.

[19] These numbers are the same as PGE's deadband, but, because PGE is subject to SB 408, PGE's deadband is actually 40% greater than this.

portion of the risk of normal gas cost variations for which customers are currently responsible. We counterbalance this by shifting more of the risk of significant commodity cost variations to customers, who are in a better financial position to absorb significant cost increases, and who should not be expected to over-pay when gas costs decrease significantly.

In UE 180, we proposed an initial sharing band of 50-50, and only then, an outer sharing of 90-10. However, we have taken into consideration a concept expressed by a PGE-hired consultant, whose report PGE included in its Testimony, regarding the regulatory backstop provided by the much wider base of financial support that can be provided by customers. This financial backstop provided by customers protects the utility's financial integrity when a business risk is realized that is beyond the utility's ability to manage.

> Utilities are generally given the opportunity to earn a return, but not a guarantee that the return will be earned. The return is put at risk to the utility's operational performance and to factors under the control of the utility management. Whether fuel price risk, for example, is appropriately placed on the utility may depend on the tools the utility has or has not been given with which to mitigate it. Certain risks may just be too large for the utility reasonably to mitigate. In that case ratepayers, with greater overall financial resources, may appropriately be asked to bear the risk.

Jacobs, Jonathan. PA Consulting Report for PGE, July 10, 2006 at 8-45.[20]

Large cost excursions often result from major market or environmental disruptions which, though we expect the utilities to manage such events to the best of their ability, are not a part of normal business variability. Therefore, we propose that

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[20] Jacobs, Jonathan. PA Consulting Report – Portland General Electric: Hourly Power Cost Simulation. July 10, 2006 at 8-45. The report is available in Docket UE 180, PGE Exhibit 1803 (quoted from PGE/1803/Lesh/49).

customers bear the bulk of these risks, while continuing to maintain a utility's stake in such cost excursions through the utility's 10% share.

D. The Importance Of A Risk-Reward Sharing Mechanism

CUB values the utilities' teams of gas-procurement and risk-management experts. We want a gas utility's board of directors to be worried about gas costs, because customers worry about gas costs. Customers pay the rates that the Commission establishes, but we rely on the utility to manage its supply options in order to minimize costs. The importance of a risk-reward sharing mechanism is that it keeps the utility and its shareholders personally invested in gas commodity costs.

The Commission moved away from a 100% pass-through of gas commodity costs in a 1989 Order, the first conclusion of which is:

> A Purchased Gas Cost Adjustment tracking tariff should be implemented which contains a risk/reward mechanism.

UG 73 OPUC Order No. 89-1047 at 12.

Earlier in that Order, the Commission describes the benefits for customers and shareholders in introducing a sharing mechanism:

> Both [PGE's] PCA and [Interruptible Sales Adjustment] tariffs have served as incentive mechanisms which share risks and rewards with utility shareholders for the results of relaxed or aggressive management of costs and market share.

UG 73 OPUC Order No. 89-1047 at 11.

We have no reason to believe that the Commission's fundamental rationale for a risk-reward sharing mechanism is no longer applicable. At its foundation, the Commission's rationale was that sharing the risks and rewards of the utility business helps to align the interests of shareholders and customers. Despite the evolution of the natural gas market, it would be hard to argue that this premise is no longer true. CUB's proposed PGA mechanism is grounded in this rationale from the Commission's Order in 1989, but it reflects the Commission's more-recent approach to normal utility business risk, and how utilities and customers are better suited to share different portions of a utility's overall risk.

IV. Conclusion

In order to update Oregon's gas utilities' PGA mechanisms to better reflect both the risks and rewards of utility business, as well as the role customers can play as a backstop for a utility's financial integrity, we propose the following risk-reward sharing mechanism for all three Oregon utilities. This risk-reward sharing would apply to the difference between gas commodity costs forecast in the utilities' Fall PGA filing and actual gas costs:

Earnings Deadband	±100 basis points ROE
Gas Cost Deadband	-75 to +150 basis points ROE for gas utilities not subject to SB 408 -45 to + 90 basis points ROE for gas utilities subject to SB 408
Gas Cost Sharing	90-10 (customer-utility)

Respectfully Submitted,
December 4, 2007

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Utility Analyst

CERTIFICATE OF SERVICE

I hereby certify that on this 4th day of December, 2007, I served the foregoing Opening Comments of the Citizens' Utility Board of Oregon in docket UM 1286 upon each party listed below, by email and, where paper service is not waived, by U.S. mail, postage prepaid, and upon the Commission by email and by sending 6 copies by U.S. mail, postage prepaid, to the Commission's Salem offices.

Respectfully submitted,

Jason Eisdorfer Attorney #92292
The Citizens' Utility Board of Oregon

W=Waive Paper service, C=Confidential, HC=Highly Confidential

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