BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 294

In the Matter of	)
	)
PORTLAND GENERAL ELECTRIC COMPANY	)
	)
Request for a General Rate Revision	)

OPENING TESTIMONY OF THE

CITIZENS' UTILITY BOARD OF OREGON

June 15, 2015

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Our names are Bob Jenks and Jaime McGovern, and our qualifications are listed in CUB Exhibit 101.

I. Introduction

CUB participated in settlement discussions and several issues were settled. CUB expects that a stipulation setting forth the settlement agreement will soon be finalized and filed with the Commission. Therefore, we will not address the issues that we anticipate are part of that settlement package.

In our Opening Testimony, CUB will make following arguments:

- PGE has failed to justify its proposed January 1 rate increase;
- The Residential Exchange Credit is not a rate case issue and should have no impact on this case;
- PGE has under-forecasted Other Revenue;

- PGE's proposal to classify transmission as 100% demand is not reasonable;
- PGE's proposal to increase the customer charge should be rejected;
- PGE's increase in rate base in recent years requires an increase in the PCAM deadbands; and
- PGE has failed to examine the benefits of altering its capital structure.

II. PGE has failed to justify its January 1 rate increase.

PGE filed this General Rate Case (GRC) with a rate effective date of January 1, 2016. But PGE does not need a rate change on January 1, 2016. According to PGE, without the January increase, PGE's ROE would be 8.8% before Carty comes online.[1] While the Commission authorizes a specific target for ROE, it is generally accepted that there is a range of reasonableness -- just because ROE is above or below the authorized level does not mean that a utility is not earning a reasonable return. And according to the Staff analysis in PGE's last GRC, an 8.8% ROE is still within the range of reasonableness.[2]

If PGE does not need a rate increase in January to ensure reasonable earnings, why did PGE file this case? The answer is clear. PGE consistently files a general rate case to conclude 2 to 6 months before a major new generating investment is forecast to come online. It has been true for Tucannon[3] and Port Westward 2[4] and it was true for Port Westward 1.[5] The only exception is Coyote Springs, which came online 9 months

[1] UE 294 - PGE/200/Tooman-Brown/3.
[2] UE 283 - Staff/200/Muldoon/24.
[3] UE 283 - PGE/400/Pope - Lobdell/16.
[4] UE 283 - PGE/400/Pope - Lobdell/21.
[5] UE 180 - CUB/200/Jenks-Brown/2.

after the last general rate case ended, but PGE had an agreement with OPUC Staff to allow it to bring on Coyote Springs with a tracker filed 90 days before the expected in-service date and an "attestation by a corporate officer" that the plant was operational.[6]

PGE has found a way to manage the regulatory system to ensure that it bears no regulatory lag for its capital investments in new generating plants like Carty: file a two stage rate case with the first stage ending within 2 to 6 months of the expected date for the new plant. This allows PGE to get the second plant approved as a second stage to that rate case. This means that approval and a tariff are in place before the plant is operational, so there will not be a single day of regulatory lag.

In addition, based on the issues that have been settled in principle, the January increase is getting smaller. While there was no justification for the increase when the Company filed its case, there is certainly no justification now. CUB recommends that no price increase be authorized on January 1, 2016 because the Company's forecasted earnings do not support such an increase.

III. The Residential Exchange Credit is not a rate case issue and should have no impact on this case.

The BPA Residential Exchange Credit (Res Ex Credit) due to PGE's residential and small farm customers is increasing and PGE includes its affect in its pricing testimony and exhibits:[7]

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[6] OPUC Order No. 95-322, Appendix D, page 3.
[7] UE 294 -PGE/1400/Cody /2.

Table 1
Estimated Cost of Service Rate Impacts

Schedule	Jan. 1, 2016	Carty	Total
Schedule 7 Residential	-1.2%	4.3%	3.1%
Schedule 32 Small Nonresidential	1.8%	4.2%	6.0%
Schedule 83 31-200 kW	0.4%	5.0%	5.3%
Schedule 85 201-4,000 kW	-1.6%	5.5%	3.9%
Schedule 89 Over 4,000 kW	-2.3%	6.3%	4.0%
Schedule 90 100 MWa	-1.7%	6.6%	4.9%
COS Overall	-0.7%	4.7%	4.0%
COS & DA Overall	-1.0%	4.7%	3.7%

PGE expects that the Res Ex Credit will increase by $15 million to a total of $65 million. The Residential Exchange is a requirement of NW Power Act, which requires BPA to exchange power with Investor-Owned Utilities in order to share the benefits of federal hydropower specifically with residential and small farm customers.[8] Utilities, like PGE, are required to pass this credit through to their residential and small farm customers. PGE has no discretion with how to use this revenue.

To be clear, CUB does not believe that PGE has done anything improper with the Res Ex Credit, but we are concerned with two impacts of including the credit in the pricing exhibits and tables.

First, it hides the real effect of PGE's rate hike on customers. PGE is proposing to increase the rates it charges to residential customers in January, but the rate case filing is telling customers that their rates are going down by 1.2%.

Second, it could affect charges to customers. PGE uses a Customer Impact Offset (CIO) surcharge/sur-credit to protect customer classes with the highest rate increases. PGE will cap increases at a certain level, and the lost revenue will be charged to other classes of customers through a CIO. Typically, such a surcharge will fall on customer

[8] http://www.bpa.gov/Finance/ResidentialExchangeProgram/Pages/default.aspx.

classes that are receiving an increase that is less than the average increase. Hence, the relative rate changes between rate classes are what drive the CIO.

In Oregon, costs are functionally allocated (generation on generation marginal cost, distribution on distribution marginal cost, etc.). Because of this, as the revenue requirement changes so does the relative rate changes among rate classes. A rate class that is currently receiving an increase that is larger than the average increase could end up with an increase that is below the average increase. So while PGE is not proposing to charge a CIO to residential customers in its initial filing, this could change as the case progresses. It would be inappropriate to include the Res Ex Credit in any analysis that triggered a CIO. The Res Ex Credit should be applied after the application of the CIO. It isn't merely a matter of aesthetics. Incorporating the Res Ex Credit into the rate change before the CIO calculation could create a material (possibly adverse) impact for the customers who are supposed to receive the benefit of the Res Ex Credit from BPA via PGE, its custodian. One could imagine a circumstance where residential customers have an increase that is greater than average before the application of the Res Ex Credit, so without the credit, it is clear that the CIO would not be charged to residential customers. However, after the Res Ex Credit, residential customers could have one of the lower rate increases, causing them to have to pay a CIO. In effect, the Res Ex Credit would trigger the CIO and residential customers would then receive less than the full benefit of the Res Ex Credit.

While PGE is currently not proposing that residential customers pay a CIO, CUB nevertheless recommends that PGE clearly state its rate impact both with and without the Res Ex Credit and that it should be applied only after the CIO.

IV. PGE has Under-Forecasted Other Revenue.

In addition to revenue from customers established through rates set by this Commission, PGE has several other relatively small sources of revenue from things like steam sales and pole attachments. These are classified as "Other Revenue" and act as an offset to revenue requirement before the revenue requirement is charged to customers. In UE 283, PGE forecasted 2014 Other Revenue as $22.6 million.[9] In this current rate filing, PGE's exhibits show that the actual amount of other revenue in 2014 was $27.5 million.[10] This is a differential of $4.9 million. This means that almost $5 million of revenue requirement that was charged to customers should have been offset by Other Revenue.

CUB went back over PGE's last several rate cases to examine PGE's forecasts of Other Revenue to see how accurate they were. CUB Exhibit 102 shows the results of that examination. Since 2006, CUB identified 7 years where PGE forecasted Other Revenue in a rate case and later, in another rate case, provided actual results:[11]

Year	Forecast (in millions)	Actual (in millions)	Differential
2006	17.7	17.3	-0.4
2008	17.8	20.6	2.8
2010	19.9	26.2	6.3
2011	21.0	22.4	1.4
2012	21.4	24.7	3.3
2013	23.0	24.9	1.9
2014	22.6	27.5	4.9

This chart shows that PGE regularly under forecasts Other Revenue. The year 2006 was the last time the Company over-forecasted. While the most recent forecast was

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[9] UE 294 - CUB Exhibit 102.
[10] UE 294 - PGE/202/Tooman-Brown/1.
[11] *Ibid.*

off by $4.9 million, on average, PGE has under forecasted Other Revenue by $3.0 million over the past 8 years. CUB recommends that PGE's Other Revenue be adjusted based on this historical forecast error: $3.0 million should be added to PGE's forecast of Other Revenue, reducing the amount of Revenue Requirement that is allocated to customers.

V. PGE's proposal to classify transmission as 100% demand is not reasonable.

PGE is proposing to recover its transmission revenue requirement entirely through demand--or capacity--related charges by assigning the revenue requirement to a 12 month coincident peak basis:

> I allocate the transmission revenue requirement consistent with how PGE's FERC transmission prices are determined, therefore on a twelve coincident peak basis (12-CP).[12]

This is a significant change from PGE's proposal in the last rate case;

> I also allocate the transmission revenue requirement consistent with how UE 262 prices were established, 65% based on capacity, and 35% based on energy.[13]

PGE offers little to support this change, other than offering the fact that it is consistent with its FERC prices. However, PGE's generation and transmission systems demonstrate that this change is not justified.

Consider PGE's two coal plants: Boardman and Colstrip. Boardman was authorized in 1975[14] and, while not in PGE's service territory, was built near PGE's service territory, meaning that relatively minimal additional transmission rights were required. There is no coal production near the plant, and therefore the plant's fuel supply

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[12] UE 294 – PGE/1400/Cody/5.
[13] UE 283 - PGE/1400/Cody/9.
[14] https://en.wikipedia.org/wiki/Boardman_Coal_Plant.

must be transported by rail. PGE's investment in Colstrip came nearly a decade after its investment in Boardman.[15] Colstrip was built in eastern Montana, more than 1000 miles from Portland, [16] and is located near coal mines that have been in operation since 1924.[17] Transmission is required to get Colstrip's power from eastern Montana to PGE's service territory.

With Boardman, PGE believed the right resource strategy was to build a coal plant near its service territory and transport the coal by rail. With Colstrip, PGE believed the right resource strategy was to build a coal plant 1000 miles away, near coal mines, and transport the electricity by wire. The difference in these resource strategies is probably explained by the Staggers Rail Act of 1980, which largely deregulated the US rail industry.[18] Key among its provisions was allowing rail owners to charge any rate they wanted unless the Interstate Commerce Commission found that there was no effective competition to that rail service.[19] The Staggers Rail Act changed the economics of shipping coal by rail.

But these two coal plants show that rail transport of coal and transmission transport of electricity are substitutes for each other. With no significant coal resources near its service territory, when building a coal plant, PGE had a choice to transport coal by rail or to transport electricity by wire.

Under PGE's proposed transmission rate recovery, the recovery of costs for these two substitutes would be dramatically different. The transportation for Colstrip (electric

[15] http://www.sourcewatch.org/index.php?title=Colstrip_Steam_Plant
[16] https://search.yahoo.com/yhs/search?p=distance+from+Colstrip+Montana+to+Portland+Oregon&ei=UTF-8&hspart=mozilla&hsimp=yhs-001
[17] https://en.wikipedia.org/wiki/Colstrip,_Montana
[18] https://en.wikipedia.org/wiki/Staggers_Rail_Act
[19] *Ibid.*

transmission) would be recovered entirely from capacity. However, the transportation for Boardman (coal by rail) would be recovered as an energy charge.[20]

IRP Guideline 5 states:

> Portfolio analysis should include costs to the utility for the fuel transportation and electric transmission required for each resource being considered. In addition, utilities should consider fuel transportation and electric transmission facilities as resource options, taking into account their value for making additional purchases and sales, accessing less costly resources in remote locations, acquiring alternative fuel supplies, and improving reliability.[21]

CUB believes that assigning transmission to capacity 100 percent fails to acknowledge that transmission and fuel transportation are substitutes.

CUB recommends that the Commission reject PGE's proposal to switch the transmission revenue requirement entirely to demand. Instead, the Commission should require PGE to continue to allocate 65% of the costs of transmission to capacity and 35% to energy. CUB is supportive of PGE's approach of collecting the capacity based on a 12 CP approach.

VI. PGE's proposal to increase the customer charge should be rejected

PGE is proposing to increase the fixed customer charge to residential customers from $10 to $11.[22] PGE supports this increase by referencing its marginal cost study:

[20] UE 250 – PGE/200/Macfarlane - Gariety/4.
[21] OPUC Order No. 07-002 at 13.
[22] UE 294 - PGE/1400/Cody/10.

> Although the embedded customer costs suggest a Basic Charge of approximately $22, and the marginal customer costs sum to more than $13, I propose to increase the Basic Charge by one dollar, to $11 in order to better match prices to costs, consistent with the principle discussed above.[23]

However, PGE Exhibit 1301 shows that the marginal customer cost for residential customers is $68.88 or $5.74/month.[24] Even when the cost of the meter ($20.22) is added to the customer cost, it still only brings the cost to $7.43 per month.

During the 1990s, there were a series of contested proceedings, including one that was a generic review of the use of marginal cost studies. During this time, CUB's perception was that rate design in Oregon was based on a set of principles. While CUB is unaware of any order that carefully lays out these principles, CUB believes that they have been the basis for marginal cost and rate design decisions and two of them are important in this case:

1) Rate Design should be done in a manner that encourages conservation. This is accomplished by charging most costs to customers as variable charges and using an inclining rate block that ensures that the benefit of conservation is greater than the average energy charge.

2) Fixed cost recovery is limited to the direct costs of a particular customer: the line drop, the meter and billing, etc. Costs that are shared by customers, whether those costs are line transformers, conductors, or the call center, should not be included in a fixed monthly charge.

CUB recommends that the Commission reject PGE's request to increase the fixed customer charge.

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[23] *Ibid.*
[24] UE 294 - PGE/1301/Macfarlane-Werner /3.

VII. PGE's increase in rate base in recent years requires an increase in the PCAM deadbands.

PGE has been on a capital spending spree in recent years. In 2009, PGE's total rate base was $2.37 billion.[25] PGE forecasts two different figures for rate base in this filing. Before Carty, PGE will have a rate base of $3.99 billion, and after Carty will have a rate base of $4.47 billion.[26] This is nearly double what it was in 2009.

CUB believes that this increase in rate base requires a reexamination and adjustment of the deadband in PGE's PCAM mechanism.

A. Original PCAM Order.

The original PCAM was designed by the PUC after a contested case where PGE, Staff and CUB all proposed different versions of a PCAM. The Commission was clear that a PCAM needed to have an earnings test and an ROE deadband:

> We conclude that a PCAM 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.
>
> 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… Second, we will set a deadband so that PGE will absorb some normal variation of power costs. We are persuaded by CUB's arguments, in this case and in dockets UE 165 and UM 1187, that an asymmetric deadband is necessary to ensure that the PCAM is revenue neutral. *See* UE 165/UM 1187, Order No. 05-1261, 10. The deadband for the power cost variation will be range from 75 basis points ROE below the base level of NVPC included in rates, to 150 basis points ROE above. As we noted in AR 499, we are well aware of the double whammy effect on SB 408, *see* Order No. 06- 532, 10, and we have considered that impact in the design of this

[25] UE 197 - PGE/209/Tooman-Tinker/ 1.
[26] UE 294 - PGE/209/Tooman-Brown/1-2.

> mechanism. Further, **we agree with Staff that the ability to absorb power cost increases depends on a utility's total rate base**, and that this PCAM is narrowly tailored to suit PGE; therefore, we decline to accept PGE's arguments that a deadband should focus on a return on generation assets only. The ROE deadband should be calculated based on PGE's overall rate base. If the power cost variation is within this deadband, there will be no power cost rate adjustment.[27]

The Commission was clear that the PCAM was designed to recover power costs that were outside of the normal business risk and that the way to identify the normal business risk is through an ROE deadband. The ROE deadband meant that the mechanism was concerned with the earnings impact of a power cost variance. Rather than focus on the size of a power cost variance ($10 million, $20 million, $30 million, $40 million, etc.), the key issue was the impact that that variation had on earnings.

It is much more expensive to finance capital investment through equity than it is through debt (see discussion on capital structure below). But equity has an advantage. The cost of debt – the interest on a loan – must be paid or the debt will be in default. But equity returns are a projection, with the recognition that actual earnings will be higher or lower than the projection. An event that causes equity returns to fall a bit is well within the normal risk variation associated with investing in a utility. Through a series of deferral dockets in the early part the last decade, the Commission began using 250 basis points as a deadband for normal business risk. This was during and after the Western Power crisis when wholesale power prices were at their highest level and during a series of bad water years for NW hydro conditions. There was a great deal of discussion concerning the normal business risk for a utility.

[27] OPUC Order No. 07-015, pages 26-27 (emphasis added).

B. UM 995.

Docket UM 995 addressed a deferral related to high purchased power costs that PacifiCorp incurred after a catastrophic failure of a coal unit during the Western Power Crisis. In that docket, the PUC set up a tiered approach to deadbands and sharing:

> Using the baseline the Commission established in Order No. 01-683, PacifiCorp incurred approximately $786.7 million in excess net power costs on a total company basis during the deferral period. The sharing mechanism established in Order No. 01-420 works on the total company level and set a deadband for power cost changes equivalent to +/- 250 basis points return on equity around the baseline (a band in which the utility bears all the cost and receives all the benefit); a 50/50 sharing band for power cost changes equivalent to between 250 and 400 basis points (basis point threshold established before the effect of sharing is calculated); and for power cost changes equivalent to more than 400 basis points, a sharing in which customers bear 75 percent and the company bears 25 percent. Order No. 01-420 at 5, 29. Applying the sharing mechanism to the $786.7 million in excess power costs (of which approximately $259 million is the Oregon share) yields approximately $160 million at issue on an Oregon basis. Pursuant to Order No. 02-410, PacifiCorp is currently amortizing deferred power costs through August 31, 2002.[28]

C. UM 1071.

In UM 1071, PGE requested a deferral because of poor hydro conditions. The PUC order discussed the issue of what constitutes the normal business risk and rejected PGE's request because it was not outside of the normal business risk:

[28] OPUC Order No. 02-469, page 3.

> Staff has established a distinction between the risks that can be predicted as part of the normal course of events and those that are not susceptible to prediction and quantification. Staff calls the former stochastic risks and the latter, paradigm or scenario risks. An example of a stochastic risk is variation in hydro availability over time. An example of a scenario risk is the "perfect storm" of 2000-2001, a cascade of effects that included poor hydro conditions, cold weather, and extremely volatile power markets (UM 995).[5] We find this distinction useful to characterize the type of risk we consider appropriate for deferral.
>
> We agree with Staff that risks normally included in modeling power costs (stochastic risks) are not appropriate for deferred accounting, as long as those risks are reasonably predictable and quantifiable and have no substantial financial impact on the utility. Here, hydro variability has been included and modeled to set PGE's base rates. The hydro year on which PGE bases its application is, as CUB points out, a 1 in 4.5 year event. This cause is not extraordinary enough to justify deferred accounting.
>
> The magnitude of the financial effect on the utility is also a factor in our consideration under the discretionary stage of the decision process. For a stochastic risk to justify deferred accounting, the financial impact must be substantial. Although we decline to set a numerical criterion, we can give negative and positive examples. In UM 995, for instance, we established a deadband around PacifiCorp's baseline of 250 basis points of return on equity.[7] We allowed no recovery of costs or refunds to customers within that deadband, reasoning that the band represented risks assumed, or rewards gained, in the course of the utility business. In the Idaho Power cases, discussed below, we allowed partial recovery for a financial impact that represented approximately 700 basis points of Idaho Power's return on equity…
>
> In the present application, PGE claims that it has incurred $31.6 million in excess NVPC, only some of which is attributable to hydro replacement costs. PGE asserts that this excess NVPC amounts to 172 basis points of return on equity. This is well short of the 250 basis points of return on equity within which we allowed no recovery in UM 995. Moreover, Staff estimates the hydro related excess NVPC to be about $17.5 million, which, by extension, amounts to about 95 basis points of return on equity. That figure is about 55 percent of PGE's $31.6 million. Finally, we note that PGE claims that without deferral, its return on equity will drop to 8 percent. That is far from a dire figure. We find that the impact of excess hydro costs is not significant enough in this case to warrant a deferral.

Ultimately, these deferral dockets were highly contested and time consuming.

CUB supported a PCAM, because the PCAM would allow us to eliminate the contested deferrals and, instead, pre-establish the rules for cost recovery when power costs are outside of the normal business risk.

D. UE 180/UE 181/UE 184.

The original PCAM was designed by the Commission after receiving recommened PCAMs from PGE, Staff and CUB. The Commission ultimately established the deadbands based on basis points of ROE and stated that they should grow with ROE:

> Second, we will set a deadband so that PGE will absorb some normal variation of power costs. We are persuaded by CUB's arguments, in this case and in dockets UE 165 and UM 1187, that an asymmetric deadband is necessary to ensure that the PCAM is revenue neutral. See UE 165/UM 1187, Order No. 05-1261, 10. The deadband for the power cost variation will be range from 75 basis points ROE below the base level of NVPC included in rates, to 150 basis points ROE above. As we noted in AR 499, we are well aware of the double whammy effect on SB 408, see Order No. 06-532, 10, and we have considered that impact in the design of this mechanism. Further, we agree with Staff that the ability to absorb power cost increases depends on a utility's total rate base, and that this PCAM is narrowly tailored to suit PGE; therefore, we decline to accept PGE's arguments that a deadband should focus on a return on generation assets only. The ROE deadband should be calculated based on PGE's overall rate base. If the power cost variation is within this deadband, there will be no power cost rate adjustment.[29]

E. UE 215.

The Commission originally designed PGE's deadbands around rate base. The deadbands were established at 150 basis points above authorized ROE and 75 basis points below ROE.[30] That was modified in UE 215 when the parties to the case stipulated to the current deadband of $30 million above forecasted amounts and $15 million below forecasted amounts, which approximated the 2009 ROE deadband.[31] That

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[29] OPUC Order No. 07-15.
[30] *Ibid.*
[31] OPUC Order No. 10-478, page 10.

settlement was for the purposes of that case only, and CUB's expectation was that the deadbands would be revisited on a regular basis as rate base grew.

In UE 215 (2010), PGE proposed replacing the ROE deadband with a deadband of $10 million above or below forecasted power costs.[32] This was opposed by CUB, ICNU and Staff.[33] Parties agreed as part of settlement to replace the ROE deadband with the current deadband of $30 million above the forecasted cost and $15 million below the forecasted cost. The stipulation makes clear that it was for that rate case only and in future general rate cases, parties could propose updating it. CUB agreed to the change in the deadband because we came to believe that a monetary deadband is easier to understand and might make it easier for PGE to explain the deadband to rating agencies. But the size of the deadband was set at a level that approximated what the ROE deadband had recently been for existing rate base. In addition, CUB agreed on the monetary deadband because the agreement allowed CUB and other parties to request expansion of the deadband as PGE's rate base grew, so we could maintain a deadband that was proportional to the original levels. The stipulation makes clear that it was for that rate case only and in future general rate cases, parties could propose updating it:

[32] OPUC Order No. 10-478, page 9.
[33] OPUC Order No. 10-478, page 10.

> **IV. PCAM.** Effective for power costs beginning January 1, 2011, the power cost variance deadbands in PGE's Annual Power Cost Variance Mechanism tariff, Schedule 126, will be set as follows: The Negative Annual Power Cost Deadband will be $15 million. The Positive Annual Power Cost Deadband will be $30 million. The Stipulating Parties agree to no other changes in Schedule126 in this docket; however, no party is precluded from proposing changes to Schedule 126 in future general rate cases.[34]

In the testimony supporting the stipulation, the parties explain this change:

> **Please describe the stipulation regarding PGE's PCAM**?
>
> The Stipulating Parties agree that deadbands applicable to PGE's PCAM should be modified to fixed amounts of $30 million when power costs are higher than the base level established in rates, and $15 million when power costs are lower than the base level established in rates. Other elements of the PCAM, including the earnings test, remain unchanged. This change is for this case only. Parties are free to advocate different deadbands in future general rate cases.
>
> **What is the basis for the stipulation regarding PGE's PCAM?**
>
> In their filed testimony (lCNU/IOO, Staff/500, CUB/lOO), various parties argued that the current PCAM structure is reasonable. The parties contend that a substantial reduction in the deadbands would constitute an unreasonable shift of risk to customers and that the PCAM was operating consistent with its intended purpose and with principles identified by UE 215 Rate Case - Testimony in Support of the Cost of Capital and PCAM Stipulation the Commission in Order 07-015. In opening and rebuttal testimony, PGE supported symmetrical deadbands and narrowing the deadbands to positive and negative $10 million, along with changes to the earnings test. PGE argued that the current PCAM structure is outside of the mainstream recovery mechanisms operable for most utilities, including those with which PGE competes for capital.
>
> The proposed agreement represents a compromise of positions, and the Stipulating Parties believe the modification to the PCAM is reasonable. The Stipulating Parties note that the agreed upon fixed $30 million and $15 million deadbands are approximately the same size as the deadbands that actually applied to PGE's power costs for 2009 (as filed in UE 221) which are $29.4 million and $14.7 million respectively.[35]

[34] OPUC Order No. 10-478, Appendix D, page 3.
[35] UE 215 - Stipulating Parties/500/Johnson - Jenks - Tinker/5.

While the parties to that docket agreed to move to a monetary deadband, that deadband was sized to prevent “a substantial reduction in the deadbands” which “would constitute an unreasonable shift of risk to customers.” However, over time, the deadband has shrunk due to the growth in rate base and this has shifted risk to customers. The earnings impact of the $30 million/$15 million deadband is approximately half of what it used to be (just as rate base is approximately twice what it used to be).

F. UE 246.

The most recent Commission order establishing a PCAM was the PacifiCorp PCAM. In that case, the Commission established a monetary deadband ($30 million/$15 million), but specifically noted that the PCAM deadband was tied to the size of rate base, and referred to the precedence that had been set by the Commission with the PGE PCAM:

> In adopting a PCAM for PGE, we articulated general principles that form the basis of a well-designed PCAM: (1) any adjustment under a PCAM should be limited to unusual events and capture power cost variances that exceed those considered normal business risk for the utility; (2) there should be no adjustments if the utility's overall earnings are reasonable; (3) the PCAM's application should result in revenue neutrality; (4) the PCAM should operate in the long-term to balance the interests of the utility shareholder and ratepayer; and, implicitly, (5) the PCAM should provide an incentive to the utility to manage its costs effectively.
>
> Applying those principles, we adopted a PCAM structure for PGE as follows. First, we established a deadband so that PGE would absorb some normal variation of power costs. If the power cost variation fell within the deadband, there would be no power cost rate adjustment. We concluded a power cost deadband should be calculated based on POE's overall rate base. To ensure the PCAM was revenue-neutral, we adopted an asymmetric deadband that did not change rates when excess power costs were less than the equivalent of 150 basis points of authorized ROE or when power cost savings were less than the equivalent of 75 basis points of the utility's ROE…
>
> Later, we adopted a stipulation that modified POE's PCAM in one respect-changing the deadband from basis points to a set dollar amount.

> Under this modification, the negative annual power cost variance deadband was set at $15 million, and the positive annual power cost variance deadband was set at $30 million.
>
> After reviewing the factual record and the parties' arguments in this proceeding, we conclude that our reasoning used to establish a PCAM for PGE remains sound and applies equally with respect to establishing a PCAM for Pacific Power.[36]

While the Commission established a monetary deadband of $30 million/$15 million similar to PGE's deadband, the Commission was clear that the deadband was related to rate base: "***We base our adopted power cost deadband on Pacific Power's authorized rate base, rather than on the utility's net power costs. In determining an appropriate power cost deadband, we look to the size of the utility's rate base and to the utility's authorized ROE.***"[37]

Because the basis for the deadband is tied to rate base and because PGE's ratebase has grown from $2.4 billion to $4.4 billion after Carty, CUB proposes to update the deadbands. Based on the rate base ***before*** Carty, and sticking to the 150/75 basis points as the basis of the deadband, 150 basis points would provide a deadband of $59.8 million, which CUB proposes to round to $60 million and establish a deadband of $60 million above forecasted costs and $30 million below forecasted costs.

[36] OPUC Order No. 12-493, pages 13-14.
[37] OPUC Order No. 12-493, page 15 (emphasis added).

VIII. PGE has failed to appropriately consider the benefits of altering its capital structure.

The Company states that it has a long term financial goal to "maintain our capital structure at 50% equity and 50% debt.”[38] CUB believes that the prudence of this goal should be investigated and determined.

The Company states:

> It is the optimal debt-to-equity ratio for PGE because it offers a balance between the ideal debt-to-equity range and minimizes our cost of capital. The equity portion of PGE's capital structure is important because it represents how PGE finances its cash needs. In addition, the equity portion helps offset the leverage and risk that PGE encounters, in part, as it finishes its large capital expenditure program.[39]

As discussed above, other utilities in other jurisdictions and other utilities under the authority of the Oregon PUC vary from the 50/50 debt equity structure, and while CUB is not recommending that PGE mirror the structure of any other particular utility, we believe that the Company should continue to pursue the most efficient form of raising funds for resources that will be used to serve customers.

The Company is vigilant about its ability to attract investor funds and should be active in maintaining solid financial performance. In each of the Company's recent annual rate cases, the Company discusses the role of ratings agencies and their various considerations. Although debt/equity structure is a component, it is not the only component. CUB believes that other favorable factors are at play for the Company and should be considered in the context of determining an appropriate debt/equity structure. As a regulated utility, PGE has characteristics that are unique to its sector.

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[38] UE 294/PGE/1000/Hagar-Greene/21.
[39] *Ibid.*

> The bonds of regulated utilities have always been solid fixtures in core fixed income portfolios. For good reason – utilities arguably enjoy the most stable business profiles in the corporate bond universe. Their every move is scrutinized by state regulators and cash flows tend to be very predictable.[40]

CUB provides perspective and background in our arguments below, and proposes a possible debt equity structure.

A. A least-cost resource can become an overpriced resource with the wrong financing.

In the course of the Company's IRP process, it is required to look forward, identifying resource needs and demonstrating least-cost resource options to fill that need. Once a resource is identified and acknowledged in the context of the IRP, there are still plenty of components that can affect the final cost of the resource to the ratepayers.

Imagine that one were to purchase a car, and had the foresight to shop around. Suppose the identical car was available at several dealerships. At dealership A, the car was \$10,000, and at dealership B, the same car was \$12,000. At first glance, it seems obvious that the least-cost approach would be to purchase the car from Dealer A. However, if we understand that Dealer A only allows in-house financing, which will cost 25%, then the real cost of the car, if paid back in one year, becomes \$12,500. Dealer B accepts your credit card which currently has a 0% offer. Then, suddenly, the car at Dealer B becomes the more economical approach.

CUB does not propose that the Company is able to finance Carty on a credit card. However, the method of funding a purchase can have a material impact on the real cost of

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[40] Another Major Capital Cycle for Utilities: Why We Prefer First Mortgage Bonds, Galliard capital management.

the resource. With 30 year treasury rates currently at 3.10%,[41] and the Company's proposed return on Equity of 9.9%,[42] there is a significant gap between the after-tax cost of first mortgage bonds[43] and issuance of shareholder equity. The Company can continue to argue that there are risks to increasing the level of debt above 50/50, and while this is true, that risk needs to be quantified. In particular, in UE 197, the Company proposed a 50/50 debt/equity structure, while its proposed cost of debt was 6.57%.[44] Today, the cost of debt is much lower,[45] and the Company still proposes the same capital structure.[46]

Moreover, one must consider that equity has a tax incidence, and at an approximate equity tax rate of 40%, the cost to ratepayers for a dollar of capital funded through equity is 14 cents,[47] while the same dollars' worth of resource financed through debt has a cost of approximately 4 cents.[48]

Debt is now significantly cheaper than it was several years ago:

PGE Long-term Debt Issuance ($ in millions)

Amount	Issuance Date	Coupon	Maturity
$100	8/18/2014	4.39%	2045
$100	10/15/2014	4.44%	2046
$80	11/17/2014	3.51%	2024
$75	1/15/2015	3.55%	2030

[49]

[41] As of 6/12/15: http://www.treasury.gov/resource-center/data-chart-center/interest-rates/Pages/TextView.aspx?data=yield
[42] UE 294 – PGE/1000/Hager – Greene/1.
[43] PGE uses First Mortgage Bonds (FMBs) to finance debt. UE 294/PGE/1000/Hager - Greene/19.
[44] UE 197 - PGE/900/Hager – Stathis/3.
[45] Portland General Electric 2014 Annual Report, page 58: http://files.shareholder.com/downloads/POR/11173558x0x817873/3741d836-468a-4f1b-ab83-e67e1c88511b/PGE_Annual_Report.pdf.
[46] UE 294 - PGE/1000/Hagar-Greene/21.
[47] At the Company's proposed 9.9 ROE, we have .099 x (1+.40) =.14
[48] The current treasury rate of 3.10+ 100 basis points.
[49] Portland General Electric 2014 Annual Report, page 58:http://files.shareholder.com/downloads/POR/11173558x0x817873/3741d836-468a-4f1b-ab83-e67e1c88511b/PGE_Annual_Report.pdf.

As such, the question must be asked: at what cost of debt is it economical for the Company's shareholders to take on the burden of increased leverage?

B. What is the impact of a shifting debt/equity ratio?

Suppose that a company, which has $10,000 in assets, is financed with 100% equity. Then the Company, in a market with a 4% price fluctuation risk, absorbs that equity across 100% of its assets. However, if the same company now moves to a 50/50 structure, then the same 4% fluctuation is absorbed by the shareholders that hold the 50% equity or $5,000 worth of assets, because in an unfortunate economic scenario, debt gets paid first and the debt holders shoulder minimal risk. Therefore, that potential 4% price fluctuation becomes magnified to 8% (as long as the size of the company remains constant). This illustrates that companies and regulators must be attentive to the debt equity ratio, because investors, in a market with alternatives, will steer away from a company that is too heavily leveraged, all other things equal. However, all other things are not equal, and changing circumstances must be considered on a company by company basis.

C. PGE has reduced risk because the size of its rate base has doubled.

In 2009, the Company had an average rate base of $2.3 billion[50] with a 50/50 debt/equity structure and a cost of debt at 6.567%.[51] After Carty, the Company will have twice the amount in rate base at $4.5 billion. With the same debt/equity structure, the Company's rate base equity has doubled as well. One might also argue that post-recession, the exposure risk that the Company faces, has decreased. In addition, by including load serving resources in rate base, those which used to be in contracts and

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[50]50 UE 197 – PGE/200/Tooman-Tinker / 24.
[51] OPUC Order No. 09-020 at 3.

expenses, the Company has reduced its exposure to fluctuations in the market. Rate base has doubled, and yet Company has approximately the same load to serve.[52] The Company no longer faces the same risk associated renewal of Mid-C contracts or the large volume of market purchases that it did just a few years ago.[53] This larger boat should be expected to weather small storms better and more efficiently.

D. PGE has reduced risk because of its annual rate case filings.

In large part, a capital structure that is not heavily leveraged provides security against risk for shareholders. However, with PGE's recent history of annual rate case filings, the Company faces reduced risk. The risk effect of rate case filings is one-sided. In the near future, after Carty, the Company is not expected to be bringing large assets into rate base, as 94% of its load would then be served by rate base resources.[54] Therefore, if the Company has an authorized rate of return (ROR) that is sufficient to cover its costs, it will not need to come in for a rate case. If, in addition, market factor changes in the Company's favor, it is allowed to keep the financial gain and can choose to extend the time between rate cases. On the other hand, if market conditions change, many mechanisms are in place to reduce the negative impact on shareholders, including, but not limited to the Renewable Adjustment Clause (RAC), authorizing dollar for dollar recovery on renewables, and the PCAM, shifting excess costs of fuel on customers if, say, natural gas prices spike. The Company, if conditions move below acceptable levels,

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[52] The Company expects only 1% load growth in 2015, consistent with recent years - Portland http://investors.portlandgeneral.com/common/download/download.cfm?companyid=POR&fileid=815699&filekey=C9E3CFDB-6CFD-4BDB-A8DC-C5D40E309FF1&filename=PGE_Investor_Presentation_March_2015_FINAL.pdf.

[53] UE 294 - CUB/100/Jenks-McGovern/8.

[54] http://investors.portlandgeneral.com/common/download/download.cfm?companyid=POR&fileid=815699&filekey=C9E3CFDB-6CFD-4BDB-A8DC-C5D40E309FF1&filename=PGE_Investor_Presentation_March_2015_FINAL.pdf pg 28.

can file for a general rate increase. In fact, this rate case, excluding Carty, is an example of a filing by the Company when rates were still sufficient to cover costs while still allowing for a reasonable rate of return. The Company has demonstrated that it is willing to file rate cases in close proximity to eliminate risk of under-recovery.

E. PGE has strong financials and can attract capital

As mentioned above, PGE has been steadily building its rate base for the past 5 years. To do so, they have had to attract over a billion dollars in capital.[55] It is clear to CUB that a 100% equity position would be unduly rigid and a 100% debt position would be infeasible. However, CUB does not agree that implies that a 50/50 debt equity capital structure is sacred. Instead, CUB believes that the Company should revisit its target structure on a regular basis. Other companies maintain various debt equity ratios in their capital structure:

Utility	**State**	**Year**	**Approved Capital**	
			Debt	**Equity**
Sierra Pacific Power[56]	NV	2013	53.06%	46.94%
PacifiCorp[57]	WA	2013	50.62%	49.38%
Black Diamond Power Co.[58]	WV	2012	56.00%	44.0%
Commonwealth Edison[59]	IL	2012	53.35%	46.12%
National Grid[60]	RI	2012	51.03%	48.78%
Puget Sound Energy[61]	WA	2012	54.00%	46.00%

[55] http://investors.portlandgeneral.com/common/download/download.cfm?companyid=POR&fileid=600181&filekey=AD9EA144-57EC-4097-A96D-3F0A925D4643&filename=Official%20PGE%20Investor%20Presentation%20Sept%202012.pdf pg 19.
[56] *In re Sierra Pacific Power Company d/b/a NE Energy*, Docket Nos. 13-06002, 13-06003, 13-06004, 2013 Nev. PUC LEXIS 281, 14-15 (Dec. 18, 2013).
[57] *Washington Utilities and Transportation Commission v. PacifiCorp d/b/a Pacific Power & Light Co.*, 2013 Wash. UTC LEXIS 1010, 5 (Dec. 4, 2013).
[58] *In re Black Diamond Power Co.*, 2012 W.Va. PUC LEXIS 1169, 35-36 (Jun. 7, 2012).
[59] *In re Commonwealth Edison Co.*, 2012 Ill. PUC LEXIS 272, 317-318 (May 29, 2012).
[60] *In re Narragansett Electric Co. d/b/a National Grid*, 2012 WL 1437571 (R.I.P.U.C.), 2 (Apr. 13, 2012).

PGE demonstrates improvement in its financial position by increasing dividends from \$1.00 to \$1.09 in the past 5 years.[62] This hasn't hurt the Company in the eyes of its ratings agencies either, as it "received two upgrades on its long-term debt from Moody's in the past two years."[63] To its investors, PGE touts these successes, noting that since the last rate case, earnings per share, return on investment and net income have all increased.[64] In testimony, PGE expresses its concerns about ongoing risks, such as hydro fluctuations and economic performance, which could affect its financial performance. However, hydro risks have been substantially lessened with the retirement of the Mid-C contracts and their replacement by Carty and economic conditions continue to improve

F. Recommendation

CUB recommends that the Company perform quantitative analysis examining the costs and benefits of alternative capital structures. In addition, CUB recommends with the large increase in rate base and spending trends that the Company currently employs, the large rate base footprint, with approximately the same load and customer size, can absorb existing risk. In particular, CUB recommends that the Company reduce its equity portion by 5% for a 55/45 debt/equity structure. Alternatively, the Commission could penalize the Company, mandating a reduction in equity of 2% for not producing rigorous analysis of capital structure.

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[61] *Washington Utilities and Transportation Commission v. Puget Sound Energy, Inc.*, 297 P.U.R. 4th 1, 7-9 (May 7, 2012).
[62] http://files.shareholder.com/downloads/POR/11173558x0x40727/42ebd67c-4652-4e6b-8713-a6a961e4bbf4/factsheet.pdf
[63] UE 294 – PGE/1000/Hager – Green/ 5.
[64] http://investors.portlandgeneral.com/common/download/download.cfm?companyid=POR&fileid=815699&filekey=C9E3CFDB-6CFD-4BDB-A8DC-C5D40E309FF1&filename=PGE_Investor_Presentation_March_2015_FINAL.pdf
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IX. Conclusion

In Conclusion, CUB recommends the following:

- There should be no January 1 rate increase because PGE filed this case even though its expected earnings in January will still be reasonable.
- The Company should not include the Residential Exchange Credit in its pricing workpapers, and the credit should be applied ex-post of the CIO.
- The Company has consistently under-forecasted Other Revenue in recent rate cases. This should be corrected using historical forecast error as a guide by increasing Other Revenue by $3.0 million.
- The Company has not demonstrated justification for changing the allocation of transmission costs, and should continue to allocate energy costs to both energy and capacity. CUB recommends the Commission allocate 65% of transmission costs to capacity and 35% to energy with the capacity charges being based on a 12 CP approach.
- PGE's proposal to increase the residential customer charge should be rejected. It is not supported by the filing.
- The deadbands in PGE's PCAM should be adjusted to account for the fact that its rate base has doubled in the last few years. CUB recommends that the monetary deadbands be updated based on a 150/75 basis point deadband. This would create an asymmetrical deadband of $60 million and $30 million.
- PGE failed to consider whether current interest rates should be reflected by changing its capital structure. CUB recommends that the Commission

impose a capital structure of 55% debt/45% equity. As an alternative, CUB recommends that the PUC reduce the equity portion of the capital structure by 2% (from 50% to 48%) to penalize the Company for its failure to provide any analysis to support its capital structure.

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NAME:	Bob Jenks
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EXPERIENCE:	Provided testimony or comments in a variety of OPUC dockets, including UE 88, UE 92, UM 903, UM 918, UE 102, UP 168, UT 125, UT 141, UE 115, UE 116, UE 137, UE 139, UE 161, UE 165, UE 167, UE 170, UE 172, UE 173, UE 207, UE 208, UE 210, UG 152, UM 995, UM 1050, UM 1071, UM 1147, UM 1121, UM 1206, UM 1209, UM 1355, UM 1635, UE 233, UE 246, UE 283, UM 1633, and UM 1654. Participated in the development of a variety of Least Cost Plans and PUC Settlement Conferences. Provided testimony to Oregon Legislative Committees on consumer issues relating to energy and telecommunications. Lobbied the Oregon Congressional delegation on behalf of CUB and the National Association of State Utility Consumer Advocates. Between 1982 and 1991, worked for the Oregon State Public Interest Research Group, the Massachusetts Public Interest Research Group, and the Fund for Public Interest Research on a variety of public policy issues.
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Economics professor at Mesa Community College and the State University of New York from 2004–2010.

Other Revenue
(in millions)

Year	Forecast	Actual	Differential
2006	17.7	17.3	-0.4
2007		18.7	
2008	17.8	20.6	2.8
2009	20.2		
2010	19.9	26.2	6.3
2011	21	22.4	1.4
2012	21.4	24.7	3.3
2013	22.5	24.9	2.4
2014	22.6	27.5	4.9
2015	25.0		
2016	25.1		

average differential 2.957143

sources:
UE 294/PGE/202/Tooman-Brown/1
UE 283/PGE/Exhibit 302/Tooman-Macfarlane/1
UE 262/PGE/Exhibit 302/Tooman-Liddle/1
UE 215/PGE/302/Tooman-Tinker/1