BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 323

In the Matter of	)
	)
PACIFICORP, dba PACIFIC POWER,	)
	)
2018 Transition Adjustment Mechanism (TAM).	)
	)

OPENING TESTIMONY

OF THE

OREGON CITIZENS' UTILITY BOARD

June 9, 2017

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I. INTRODUCTION

My name is Bob Jenks, and I am the Executive Director of the Oregon Citizens' Utility Board ("CUB"). My qualifications are provided herein as CUB Exhibit 101.

CUB appreciates the participation of stakeholders, Public Utility Commission of Oregon Staff ("Staff") and PacifiCorp ("PAC" or "the Company") in the series of workshops that the Commission required after the Company's 2017 Transition Adjustment Mechanism ("TAM").[1] CUB believes that the workshops helped improve parties' understanding of each other's positions. In addition, CUB believes that the changes that the Company adopted in response to the workshop will be helpful throughout the course of the 2018 TAM contested case proceeding.

[1] *In re PacifiCorp 2017 Transition Adjustment Mechanism*, OPUC Docket No. UE 307, Order No. 16-482 (Dec. 20, 2016) at 1-2 ("We also direct PacifiCorp, Staff, and parties to participate in workshops to examine the following GRID issues: (1) Day-Ahead/Real-Time Transaction (DART) adjustments, (2) Energy Imbalance Market (EIM) benefit estimation, and (3) Renewable Energy Credit (REC) valuation.").

CUB is encouraged by the Company's agreement to file a Step Log with their annual TAM filing that identifies all modeling changes and their impacts, similar to the manner in which Portland General Electric its Annual Power Cost Update Tariff. This is a vast improvement to past practices where parties often had to uncover modeling changes by studying spread sheets and asking data requests. In a docket as complex as the TAM, transparency is key.

The improvements resulting from the stakeholder workshops should reduce the acrimony surrounding the annual TAM filing. CUB believes that PAC has made some improvements in how it models the Day-Ahead/Real-Time ("DART") Transaction adjustments and Energy Imbalance Market ("EIM") benefits and costs, and CUB is largely supportive of those changes. However, CUB cannot endorse the DART mechanism as we continue to have concerns about its volatility. In addition, CUB takes issue with the Company's modeling of Jim Bridger costs, and costs associated with PURPA Qualifying Facilities ("QF") expected online dates.

CUB's testimony is organized as follows:

1. Jim Bridger Coal Plant Costs;
2. QF Contracts and Delays;
3. DART Transaction Adjustments; and
4. EIM Costs and Benefits.

II. JIM BRIDGER COAL PLANT COSTS

CUB continues to believe that the net power cost ("NPC") impact of selective catalytic reduction installation ("SCR") at Jim Bridger Units 3 and 4 should be removed from the 2018 TAM because they have not been subject to a prudence review in a general rate case. As was true in its 2017 TAM, PAC's 2018 TAM increased NPC associated with Units 3 and 4 to reflect minimum operating levels of both units.[2] The Company asserts that a $168,000 increase is necessary because of the environmental upgrades (installation of SCRs) that took place and increased the minimum operating levels of these units.[3]

Since there has been no determination whether the SCRs PAC invested in were done so prudently, their cost does not belong in the TAM.[4] The Company states that it made a similar change to it operating costs at Bridger in its 2017 TAM filing (UE 307), but that change "was later withdrawn on a non-precedential basis in the reply update."[5] Last year, the Company gave a very specific reason for withdrawing its request: "[t]o avoid litigation over the SCR issue, the Company [was] willing to agree to the adjustment."[6] PAC fails to explain why costs that were caused by an SCR investment that has not been determined to be prudent should be included in the TAM. [7]

A. *The SCRs at Bridger Unit 3 and 4 Were Not Acknowledged*

In its 2013 IRP (LC 57), PAC attempted to justify the addition of SCRs to Bridger Units 3 and 4 based on a flawed confidential coal analysis. CUB argued that, while PAC did consider phasing out the plants rather than installing the SCRs, the Company's analysis considered the wrong cost effectiveness threshold, and the Company failed to model reasonable dates for the phase out.[8]

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[2] UE 323 – PAC/100/Wilding/13.
[3] *Id.*
[4]UE 307 – CUB 100/McGovern/4-6.
[5] UE 323 – PAC/100/Wilding/13.
[6] UE 307 – PAC/400/Dickman/14.
[7] UE 323 – PAC/100/Wilding/13.
[8] *See In re Pacificorp 2013 Integrated Resource Plan*, OPUC Docket No. LC 57, Opening Comments of the Citizens' Utility Board of Oregon at 8-20.

CUB notes that PAC has improved its modeling of Regional Haze and required environmental upgrades in more recent IRPs (*i.e.*, in IRPs after LC 57), with particular improvement in the way that it models phasing out coal units as an alternative to environmental upgrades. Although the Bridger SCRs predate PAC's improved modeling, it is worth highlighting that PAC's IRPs no longer show that SCRs are a good investment.[9]

In 2014, the Commission cited several reasons to reject the SCRs at Bridger when it declined to acknowledge them in LC 57:

> Based upon the information we have at this time, we decline to acknowledge Action Item 8c related to Bridger Units 3 and 4 for four reasons. First, some of the modeled alternatives suggest that the installations of SCRs are not the lowest cost resource option. For example, as described on page 4 of Staffs Final Comments dated January 10, 2014, alternative D runs demonstrate that it is more economical to retire Bridger 3 and 4 than to install the SCR equipment. Based upon the information we currently have, we cannot dismiss these results as unrealistic or unreasonable.
>
> Second, we concur with Staff that there are gaps in PacifiCorp's analyses. As Staff notes, PacifiCorp did not consider the potential tradeoffs between units at Bridger 3 and 4 or between coal plants to identify the most cost effective compliance options from a state or fleet perspective. Additional analyses on these issues would have resulted in more information for us to make an informed decision on acknowledgment.
>
> Third, Staff and other participants have raised several other specific issues related to the merit or lack of merit of installing SCRs at Bridger 3 and 4, such as the impact of retirement on reliability, inter-temporal and fleet trade-off analysis between units, or the impact of retirement on future transmission investments. However, we lack the necessary information in this proceeding to weigh these issues and they will be more thoroughly investigated in a future rate case proceeding.
>
> Finally, PacifiCorp is going ahead with the investments in installing SCRs regardless of our decision in this proceeding. We will undertake a

[9] *In the Matter of PACIFICORP, dba PACIFIC POWER's 2015 Integrated Resource Plan*, OPUC Docket No. LC 62, Opening Comments of the Citizens' Utility Board of Oregon at 3-4.

> thorough and fair review of the prudence of PacifiCorp's decision in a future rate case proceeding.[10]

B. *Absent Commission Acknowledgement, Costs Associated with the SCRs at Bridger Units 3 and 4 Should be Removed*

Without an acknowledgement in an IRP, there is no presumption that the installation of SCRs at Bridger was a prudent investment. The Commission stated that it will undertake a thorough and fair review of the prudence of PAC's decision in a future rate proceeding. Typically, capital investments are reviewed in a General Rate Case ("GRC"). To date, PAC has not filed a GRC where it has asked the Commission to find that the SCR investment on Bridger 3 and 4 were prudent, nor has it filed any evidence in this rate proceeding that would allow the Commission to determine the prudence of the investment in the SCRs.

If the Commission finds that the SCRs on Bridger were not prudent, typically, customers would not be asked to bear the costs associated with that investment, including the NPC at issue here. Instead, ratemaking adjustments would be made so as to hold customers harmless from the imprudent investment. In this particular instance, CUB will argue that PAC should have undertaken an analysis that is similar to what it uses today in IRPs regarding its coal plant environmental retrofits, and that such an analysis would have shown that the Company could phase out the plants by a later date than what the Company considered in LC 57. From a hold harmless perspective, this means that PAC would still have Bridger 3 and 4 operating in 2018 (because the phase out date would be later), but the SCRs would not be installed and the subsequent change in Bridger costs being proposed here would not be included. Adding these costs to the NPC in the 2018

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[10] *In the Matter of PACIFICORP, dba PACIFIC POWER, 2013 Integrated Resource Plan*, OPUC Docket No. LC 57, Order No. 14-252 (July 8, 2014) at 8-9.

TAM, as proposed by PAC, would violate the principle of holding customers harmless for imprudent investments.

C. *The Company Controls the Timing of Prudence Reviews*

It should be noted that the reason there has not been a prudence review is that the Company has not filed a rate case and asked for one. But it should not be able to seek recovery of costs associated with a capital investment without a prudence review. If the Company wishes to seek cost recovery of the Bridger SCR investments that were not acknowledged in LC 57, the proper venue is a GRC, not a TAM proceeding.

D. *The Company Could File for a Deferral*

Since the costs associated with the Bridger SCRs are not capital costs, the Company could request a deferral to track the costs until a determination of the prudence of the underlying investment is made. But, in that case, the Company would have to establish why the Bridger SCR costs rise to the level of requiring a deferral. Since the costs are less than $200,000, that might not be an easy undertaking.

III. QF CONTRACTS AND DELAYS

PAC's 2018 TAM will likely result in overcharging customers millions of dollars for QFs that are not operational. In its NPC forecast, the Company includes four new QF power purchase agreements ("PPAs") that "are expected to reach their commercial operation date (COD) in 2018 and have not been previously included in rates."[11] Last year, the Company also included [redacted][12] Based on PAC's history with QFs, there is no reason to believe that all of the

[11] UE 323 – PAC/100/Wilding/11.
[12] Confidential CUB Exhibit 102.

[redacted] QFs will be operational by PAC's projected COD CUB offers two proposals for adopting a mechanism that will protect customers from QF overpayment.

A. *UE 307 Demonstrates that the Current QF Forecasting Methodology Overcharges Customers*

Last year, the Commission rejected CUB's recommended adjustment to the Company's QF forecasting, but stated that an adjustment would be considered when additional data is available:[13]

> We decline to apply any discount factor at this time for new QF contracts. As discussed above, the attestation process for QF contract costs was adopted as part of the 2015 TAM stipulation. Under that agreement, PacifiCorp confirms in its November indicative update those new QFs it reasonably believes will reach commercial operation during the rate effective period, and also updates the expected commercial operation dates to reflect project delays.
>
> We acknowledge CUB'S undisputed claim that only 80 MW of the 96 MW of new QF generation that was forecasted for this year has become operational. As CUB concedes, however, we do not yet have concrete data to fully evaluate the 2016 forecast accuracy, because many of the QFs are forecast to begin operation at the end of the calendar year…
>
> We appreciate the parties' oversight of the QF costs, and will further consider this issue when additional data is available to evaluate PacifiCorp's use of the attestation method.

Fortunately, additional data is now available that shows that PAC's methodology is not valid. Below is a confidential list of QFs that were included in the 2017 TAM and their actual (or updated) commercial operation date. It shows that many QFs were delayed well beyond the dates forecast in the attestation process. This is not surprising, as the pattern existed throughout the UE 307 TAM proceeding. Updates during the case showed that QFs were delayed. This trend did not stop with the final update that set rates for 2017 and has continued into this year's proceeding. There is little reason to believe

[13] OPUC Order No. 16-482 at 18.

that the Company's forecast of expected commercial operation date for QFs is accurate. The Company's final update in UE 307 showed a $1.2 million reduction in cost due to delays in QFs[14]:

Contract	**August Update COD**	**November Indicative COD**
NorWest Energy 9 LLC	11/30/2016	7/31/2018
OR Solar 2 LLC	12/1/2016	7/30/2017
OR Solar 3 LLC	12/1/2016	3/15/2017
OR Solar 5 LLC	12/1/2016	3/30/2017
OR Solar 6 LLC	12/1/2016	3/24/2017
OR Solar 7 LLC	12/1/2016	7/30/2017
OR Solar 8 LLC	12/1/2016	12/31/2018

However, since this final update – since rates have been set for 2017 – several projects have had further delays.

Projects delayed since the final update include:[15]

[redacted]

[14] *In the Matter of PACIFICORP, dba PACIFIC POWER, 2017 Transition Adjustment Mechanism*, OPUC Docket No. UE 307, TAM Net Power Cost Indicative Update for 2016, (Nov. 8, 2016) at 7 or 21.
[15] Confidential CUB Exhibit 102.

The indicative filing was made on November 8, 2016. [redacted] of the projects that have been delayed were expected to have a COD approximately [redacted] after the indicative filing. [redacted] of these projects have been delayed by [redacted]. If the final update cannot predict the COD of projects that are expected to supply power [redacted], then it is not reasonable to believe that the current QF forecast process can accurately predict the COD of projects that are expected to supply power in the next 14 months.

B. *Customers Continue to be Overcharged for QFs this Year*

Inaccuracies in the forecasting methodology for expected QF CODs are causing customers to be overcharged in 2017. In the indicative filing, a change in seven QFs decreased NPC by $1.2 million. But since rates have gone into effect, a total of [redacted] QFs have been delayed.[16]

This means that customers are being significantly overcharged today for QF's that were forecast to be operational but are not. CUB notes that because PAC has designated its answer to CUB's data request as confidential in this docket,[17] CUB cannot use this as evidence to request a deferral for the remainder of 2017 and remove the inflated costs from customer bills.

However, there is no reason not to fix this problem before next year.

C. What is the Fix to This Forecasting Error?

CUB proposes two mechanisms that are designed to more accurately forecast QFs impact on the Company's TAM.

[16] Confidential CUB Exhibit 102.
[17] Protective Order No. 16-128. CUB notes that the similar update in the November indicative filing were not designated as confidential.

1. "Derate" QFs in a Manner Similar to Forced Outage Rates

First, CUB proposes a fix that is similar to what was proposed in last year's TAM: to derate QFs in a manner that is similar to Forced Outage Rates ("FOR"). It is generally recognized that utility generating plants will have some outages – stuff happens, things break. When forecasting next year's power costs, it is not known which plants will have a forced outage and when those forced outages will happen. But to assume no forced outages because of this uncertainty would not produce an accurate forecast. The solution is to look at historic performance of the generating plants and derate the plants based on a rolling average of recent historic performance.

The same methodology can be applied in the case of QF forecasted online dates. A relatively simple fix is to examine historic performance of QF contracts – what is the average delay in a contract after the final forecast – and apply this average delay to the forecast on a forward looking basis. Knowing that there is uncertainty as to which QF contracts will be delayed and for how long, does not justify forecasting zero delay of all contracts. As history has shown time and time again zero delays is not an accurate forecast.

In this case, CUB proposes that PacifiCorp compute a Contract Delay Rate (CDR), based on the rolling average of the last three years of available data. This should be based on the number of days a contract is delayed after the final TAM forecast. This CDR would then be applied to all QF contracts in the final TAM forecast.

CUB believes derating QFs is a straightforward solution that uses traditional forecasting adjustments to account for known uncertainty. The adjustment is based on actual data from actual projects. While there may be some years where the adjustment is greater than the actual project delays, there will be years where the adjustment is less than the actual project delays. Over time it should balance and produce accurate forecasts.

Last year, PAC argued that CUB's proposal undermined federal policy:[18]

> PURPA requires the Company to purchase energy and capacity from QFs at avoided cost prices under terms and conditions established by each state public utility commission. As such, the risks associated with QF performance are largely outside the Company's control. In addition, PURPA specifically mandates cost recovery. CUB's recommendation, which disallows timely recovery of certain QF contract costs, undermines PURPA's policy of utility cost recovery.

CUB disagrees. CUB's proposal is not designed to undermine cost recovery but to ensure accurate cost recovery. PAC's suggestion that PURPA's mandate for cost recovery requires Oregon to set next year's rates based on an assumption that there will be no delays to QFs is not reasonable, just as it is not reasonable to assume that PAC's power plants will not have any forced outages.

2. Require an Annual QF Deferral

As an alternative, CUB believes that requiring an annual QF deferral could also fix the problem. There are two ways this can be done. First, no new QFs could be forecast, and the Company could file a deferral to track the actual cost of QFs as they come online during the course of the year with these costs being included with a one year delay. Second, QFs costs can be included in rates as they currently are, but the Company would be required to defer the forecasted costs associated with project delays, with those costs returned to customers the following year.

Both of proposals pose the problem of an inaccurate forecast being trued up with interest the following year, which is admittedly not ideal ratemaking. However, in

[18] UE 307 – PAC/400/Dickman/88-89.

CUB's opinion, the slight procedural burden of an annual true-up is far more equitable than forcing PAC's customers to systematically be overcharged for QFs that do not come online, and therefore do not serve their needs. Finally, CUB notes that this directly address PAC's objection to derating the contracts because it allows for full cost recovery but ensures that over recovery does not happen.

IV. DART ADJUSTMENT

In previous TAMs, CUB has asked the Commission to reject the DART adjustment. While CUB will not be making the same recommendation in this proceeding, our concerns regarding the adjustment remain.

At the core of CUB's concern is the effect of using non-normalized costs and volumes as part of a weather normalized mechanism. CUB agrees that there is a problem with how GRID models sales and purchases, but continues to believe that the solution is to fix GRID so it models the actual products that are available to PAC. While this will make GRID more complicated it will produce a normalized forecast of the purchases and sales.

Using non-normalized costs and volumes indirectly allows the Company to use this mechanism to recover non-normalized costs, increases volatility of rates because non-normalized costs are more volatile than normalized costs, and produces the potential of non-normalized costs being double recovered – recovered in the TAM and in the power cost adjustment mechanism ("PCAM") since the PCAM also allows the Company under some circumstances to recover non-normalized power costs. For example, if low hydro conditions caused a power cost increase that was greater than the PCAM deadband, the same volumes of non-normalized purchases that would be included in the PCAM would flow through the DART over the next five years.

A. *TAM Workshops*

While CUB appreciates the workshops that allowed parties to explore issues with the DART adjustment, those workshops reinforced CUB's concerns about the volatility of the mechanism. CUB's ability to identify the causes of this volatility is limited due to lack of data. There are only a few years of relevant data to look at, so there are a limited number of non-normalized conditions and there are likely multiple variables affecting the mechanism. For example, if this mechanism is influenced by both hydro conditions and weather, and the harshest weather in our data set also has some of the best hydro conditions in the data set, then it makes it difficult to isolate the effect of either.

B. *Putting a Collar Around the Adjustment*

If the DART adjustment is going to continue, CUB believes that there it will be necessary to identify the drivers of the volatility and place a collar around the mechanism that removes the most extreme years from the rolling adjustment. This is similar to what is done with Forced Outages. While most Forced Outages are used to calculate the Forced Outage Rate, outages that are consider extreme or "outliers" are removed from the calculation because they should not be used in normalized forecasting.

With the general lack of data, however, it is difficult to define when a year should be removed. So for the time being, CUB is content with placing a collar around the mechanism that removes PCAM years from the rolling adjustment. This means there will still be a DART adjustment in PCAM years, but the 12 months of net power costs that cause the PCAM would not be included in the 60 months of data used to calculate the DART.

V. CUB IS SUPPORTIVE OF EIM CHANGES

CUB supports PAC's EIM inter-regional benefits as an improved methodology of forecasting.

PAC's old methodology modeled inter-regional transfers based on the available transmission between PAC and CAISO after GRID models power costs. The problem presented by PAC's old methodology was that GRID modeled market transactions without the option of EIM. GRID will identify all opportunities for power sales that are marginally beneficial. But that is not how the Company operates. In the real world, the Company has a choice to make: should it make that power sale, or should it hold back so it has more transmission available for EIM. While GRID will make sales that are just barely in the money, the Company is more likely to hold back on some of those sales because it expects to make a larger margin through EIM. In the real world the Company has to apply some judgment and is constantly making decisions about the trade-offs between market sales and EIM transactions. The best information we have to identify how the Company will apply this judgement is how it has applied this judgement in the past.

CUB believes that this change in methodology is appropriate and increases the accuracy of the EIM forecast of inter-regional benefits.

VI. CONCLUSION

CUB appreciates the workshops that the Commission ordered after last year's TAM and believe they have led to some real improvement, particularly PAC's agreement to file a Step Log that lists their modeling adjustments and the impacts of those adjustments.

CUB has reviewed PacifiCorp's TAM filing and recommends the following:

1. Jim Bridger 3 and 4. PacifiCorp's forecast for costs associated with the Jim Bridger Units 3 and 4 should be adjusted to remove approximately $168,000 of costs associated with the installation of SCRs on the plants, since the SCRs have not been found to be imprudent.

2. QFs. The QFs that were included in PacifiCorp's final TAM forecast for 2017 were significantly inaccurate due to significant delays associated with many of these projects. PacifiCorp should be required to calculate a Contract Delay Rate (CDR) based on its most recent three years of history and apply that rate to the QFs included in the final TAM update. As an alternative, the Company should be required to use deferred accounting to ensure that customers are not overcharged on QFs.

3. DART. CUB supports moving the DART to a 60 month basis to remove volatility. In addition, CUB believes that a collar should be established that eliminates years that trigger a PCAM adjustment from the DART's 60 month calculation.

4. EIM. The Commission should adopt PAC's proposal to eliminate the use of available transmission as the basis for inter-regional benefits and instead should use historical results. This should improve the accuracy of the forecasts.

WITNESS QUALIFICATION STATEMENT

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EDUCATION: Bachelor of Science, Economics
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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, UE 233, UE 246, UE 283, UE 296, UE 308, UG 152, UM 995, UM 1050, UM 1071, UM 1147, UM 1121, UM 1206, UM 1209, UM 1355, UM 1635, 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.

MEMBERSHIP: National Association of State Utility Consumer Advocates
Board of Directors, OSPIRG Citizen Lobby
Telecommunications Policy Committee, Consumer Federation of America
Electricity Policy Committee, Consumer Federation of America
Board of Directors (Public Interest Representative), NEEA

CUB Exhibit 102 is confidential and was submitted to each party designated to receive confidential information pursuant to Order 16-128.

UE 323 – CERTIFICATE OF SERVICE

I hereby certify that, on this 9th day of June, I served the foregoing **CUB Confidential Testimony & Exhibit** in docket UE 323 upon the Commission and each party designated to receive confidential information pursuant to Order 16-128 by U.S. mail, postage prepaid.

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