BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 390

In the Matter of	)
	)
PACIFICORP, dba PACIFIC POWER,	)
	)
2022 Transition Adjustment Mechanism.	)
	)

REDACTED

REBUTTAL AND CROSS-ANSWERING TESTIMONY

OF THE

OREGON CITIZENS' UTILITY BOARD

July 30, 2021

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 390

In the Matter of	)	
	)	
PACIFICORP, dba PACIFIC POWER,	)	REDACTED REBUTTAL AND
	)	CROSS-ANSWERING OF THE
2022 Transition Adjustment Mechanism.	)	OREGON CITIZENS' UTILITY
	)	BOARD

I. INTRODUCTION

Q. Please state your name, occupation, and business address.

A. My name is Bob Jenks. I am the Executive Director of the Oregon Citizens' Utility Board (CUB). My business address is 610 SW Broadway, Ste. 400 Portland, Oregon 97205.

Q. Please describe your educational background and work experience.

A. My witness qualification statement is found in exhibit CUB/101.

Q. What is the purpose of your testimony?

A. This testimony responds to issues raised by PacifiCorp (PAC or the Company) in its Reply Testimony, and other parties' Opening Testimony regarding PacifiCorp's 2022 Transition Adjustment Mechanism (TAM), filed with the Oregon Public Utility Commission (Commission) on April 1, 2021.

Q. How is your testimony organized?

A. First, CUB will respond to the Company's Reply Testimony as it relates to our Opening Testimony. CUB continues to have concerns about the Company's Market Capacity Caps which limit the forecast of short-term and system balancing sales, about the Company's modeling of least cost dispatch of the Jim Bridger plant, about the Huntington Coal Supply Agreement (CSA), and about the timing of next year's TAM. Second, CUB will respond to the Opening Testimony of Calpine Energy Solutions, LLC. (Calpine), specifically its proposal to improperly enable the Consumer Opt-out Charge (COOC) to go negative.

II. MARKET CAPACITY LIMITS

Q. How did PacifiCorp respond to CUB's Opening Testimony on market capacity limits or market caps?

A. The Company highlights the fact that CUB agrees that the current methodology[1] has been over-forecasting short-term market sales. However, PAC denies that the change in its resource base affects these sales. The Company is continuing to propose the same market capacity caps as it did in its Opening Testimony.

Q. CUB agrees that the current TAM methodology has been over-forecasting short-term market sales. Do you agree with the Company's analysis of this issue?

A. Not entirely. CUB reviews the PCAM every year, and there has been an over-forecast of market sales in prior TAM proceedings. However, the Company seems

[1] UE 390 – PAC/400/Staples/18, lines 5-7 ([I]n the 2013 TAM, the Commission required the Company to base these market caps on the maximum monthly capacity during the most recent four-year period.") citing *in re PacifiCorp dba Pacific Power, 2013 Transition Adjustment Mechanism,* Docket No. UE 245, Order No. 12-409 at 7-8 (Oct. 29, 2012).

to want to pin this entirely on the cap that is placed on market sales in the GRID forecast. CUB believes that there are several factors that affect this. First, GRID forecasts based on normal weather, and weather excursions that are not captured in the GRID forecast can have a significant effect on market sales and purchases. Second, looking at sales volumes and revenues overstates the forecast error because those revenues are offset by the cost of generation. Third, the development and expansion of the Energy Imbalance Market (EIM) created trade-offs with short term market sales. Fourth, the 2020 pandemic reduced electric demand across the country, which affected nearly all markets, including the wholesale electric market, and this made 2020 data unreliable. Finally, the Company's significant shift in its resources that CUB highlighted in Opening Testimony have occurred only in the most recent years.

Q. Please explain the role that normal weather and weather excursions have on this forecast?

A. GRID is a power cost forecasting model that predicts power costs based on a simulated dispatch of the Company's system under normalized weather conditions. The TAM forecasts of short-term power sales are forecasts of what power sales will be when weather is normal. But weather is not normal. Short term market sales are dependent on the availability of power to sell, and how the incremental or marginal cost of that supply compares to the market price. However, it is important to recognize that the weather's impact on availability of power is primarily about the weather as it pertains to PacifiCorp's customers, whereas the weather's impact on prices is impacted by the weather across the Western United States.

Consider what happens when the weather is mild within PacifiCorp's service territory: The Company has less load to serve and, subsequently, more power available to sell into the market. However, if there is mild weather across the entire west, then other utilities also have less load to serve and more power to sell. This depresses the demand for short-term wholesale power and reduces market prices. So, a utility likely has more power available to sell, but is facing a market with less demand and lower prices than were expected under normal weather. But if the mild weather in PacifiCorp's territory coincided with a heat wave in California or Nevada, the Company would have more power available and would have favorable market conditions in terms of demand and price.

Q. Is the effect of normalized weather limited to availability of power and the market price?

A. No. Weather has lots of effects on the wholesale market. When it is cloudy in a part of the west with a great deal of solar generation, there will be less solar generation sold into the wholesale market. But such cloudy weather could be associated with precipitation that increases hydro generation on a short-term basis for run-of-river hydro and a more medium-term basis for hydro with storage. Hot, dry weather can increase demand for air conditioning but also increase solar production. It can also lead to wildfires which can affect regional transmission or solar production. For example, the recent fire-related outages of the Oregon-California intertie during a California heat wave reduced the ability of PacifiCorp to take advantage of the high California prices. In short, there are many dynamic weather-related events that impact market sales and availability that are not captured in the GRID model.

Q. Does weather have a similar effect on power purchases?

A. Yes. PacifiCorp's testimony shows that in nearly every year since 2012, there has also been an over-forecast in market purchases.[2] Unlike a power sale, which brings in revenue, a power purchase is a cost. Therefore, when purchases are over-forecast, the Company forecasts higher costs than what actually happens.

Q. Is it fair to the Company to base rates on normalized weather, if we know the weather will not be normal?

A. Yes. Weather impacts all kinds of business. Businesses must forecast costs and demand and set prices that will allow them to be profitable. Few businesses are allowed to retroactively adjust prices to respond to weather or other events that are different than expected.

As was discussed in last year's general rate case for PacifiCorp, the Company's earnings from serving Oregon customers have been reasonable. The regulatory regime in Oregon is fair. Forecasting costs based on normalized weather has not unjustly kept PacifiCorp from earning its expected profits.[3]

Q. Please explain how looking at sales volumes and revenues overstates the forecast error.

---

[2] UE 390 – PAC/400/Staples/24
[3] *See* UE 374 – CUB/100/Jenks/32-33.

A. PacifiCorp's testimony includes tables that show the over-forecasting of short-term market sales in volume (MWh) and dollars.[4] It is important to recognize that there are costs associated with sales that do not show up in these tables. Power must be generated or purchased before it can be sold. If it is generated by a coal or gas facility, there are fuel costs. If it is purchased under contract, then PacifiCorp pays for that generation. A utility will generally sell into the market if the market price is greater than the incremental cost of production and transmission. The margin on the sale—the difference between the price and the incremental cost of production and delivery—is what counts towards the bottom line. For example, PacifiCorp forecasts that the average price for short-term firm sales in 2022 to be (begin Confidential) [redacted] (end Confidential).[5] The Company forecasts the variable power costs of Jim Bridger to be (begin Confidential) [redacted] (end Confidential).[6] This means that if the Company is using Jim Bridger to generate the power that is being sold in these short-term firm sales, its margin is (begin Confidential) [redacted] (end Confidential).

PacifiCorp's tables show that in 2018 the Company over-forecasted short-term firm and system balancing sales by 6.2 million MWh and that the dollar value of these lost sales was $189 million.[7] In that year's TAM filing, the Company was projecting that the cost of gas generation was (begin Confidential) [redacted] (end

---

[4] UE 390 – PAC/400/Staples/23-24.
[5] CUB Confidential Exhibit 102.
[6] CUB Confidential Exhibit 102.
[7] UE 390 – PAC/400/Staples/23-24.

Confidential)[8] and the average revenue from balancing sales was (begin Confidential)[redacted] (end Confidential). Therefore, if gas generation was the marginal cost unit that was supporting these sales, the lost margin on the sales would have been (begin Confidential) [redacted] (end Confidential).

PacifiCorp acknowledges that short term power purchases have also been over-forecast but argues that the magnitude of the variance for the sales is much greater than it is for purchases. While this is true when looking at the volumes and revenues associated with sales, it is not true when looking at the margin on short-term sales alone. Above, we showed that if gas was the marginal unit used to serve short-term sales, then the margin on these sales was forecast to be (begin Confidential)[redacted] (end Confidential) in 2018. But the over-forecast in power purchases over the last five years was $42.82 million.[10]

Q. Please explain how expansion of the EIM has affected short term market sales.

A. The tables in PacifiCorp's testimony begin in 2012. They show that the actual volume of short-term sales peaked in 2014, which happens to be the same year that PacifiCorp joined the EIM. In that year, PacifiCorp's EIM benefits were $4.73 million. The EIM benefits then grew significantly until they reached approximately $60 million in 2019 and 2020.[11] It is important to recognize that EIM benefits are net margin benefits that reflect the cost of producing power.[12]

---

[8] CUB Confidential Exhibit 102
[9] CUB Confidential Exhibit 102
[10] UE 390 – PAC/400/Staples/24. This figure represents the average of the last five years in table.
[11] https://www.westerneim.com/Pages/About/QuarterlyBenefits.aspx
[12] UE 296 – PAC/100/Dickman/17.

There is a trade-off between EIM and short-term sales, because generation and transmission that is committed to short-term firm sales is not available for the EIM. If the Company commits a generating unit to a short-term sale, that generating unit–or at least the portion of the generating unit that is tied to the sale—is no longer available for the EIM. If the Company's forward sales at COB use the Company's available transmission rights, then there is less transfer capacity available for EIM transactions.[13]

While the interhour dispatch of resources by CAISO in the EIM is a distinct function that is different from PacifiCorp's short-term firm and balancing sales activity, they are related. PacifiCorp has to make strategic decisions about whether or not to commit generation to forward short-term sales, which will mean that generation will not be available for the EIM and the transmission associated with that forward short-term sale will not be available.

PacifiCorp's table that shows the shortfalls in actual short-term sales versus forecasts needs to be examined within the context of a growing EIM that affects the availability of generating units and transmission pathways.

Q. Please explain how the pandemic made 2020 data unreliable.

A. PacifiCorp's tables include the 2020 calendar year. The pandemic caused large sections of the economy to shut down sharply, thereby reducing electric demand.

[13] UE 296 – PAC/100/Dickman/17.

This, of course, had significant effects on wholesale electricity markets. Market sales and purchasing data from 2020 is of very little use for predicting future sales and purchases.

Q. Explain how the Company's recent shift in resource affects short term sales.

A. CUB discussed the dramatic change in the Company's resource base between 2018 and 2022 in Opening testimony and why these changes should lead to an upward trend in power sales. The Company dismisses CUB's concerns by arguing that this change is not limited to the Company's resources but is reflective of "all owners on the system."[14]

But the Company offers no evidence that "all owners on the system" are dramatically increasing their portfolio of renewable resources and reducing fossil fuels in the manner that PacifiCorp has. While CUB agrees that there is a general trend towards a cleaner grid, what the Company has done in the last three years likely goes beyond the general trend. Over the last four years, coal generation has (begin Confidential) [redacted] (end Confidential). But the biggest change in in renewables. Company-owned wind production has (begin Confidential) [redacted][16] (end Confidential). Wind and solar under long term contracts have [begin Confidential] [redacted] [end Confidential]. But with data from 2020 being unreliable due

[14] UE 390 – PAC/400/Staples/30.
[15] CUB Confidential Exhibit 102.
[16] CUB Confidential Exhibit 102.
[17] CUB Confidential Exhibit 102.

to COVID-19's effect on the economy, the effect this change in generating resources has on market sales has yet to be seen.

In addition, the Company's own testimony states that this new generation will increase balancing sales. PacifiCorp included several new wind projects in this TAM. To demonstrate the benefits of these projects, the Company conducted a GRID run where it removed the new wind that is being added in this case. The impact was a reduction in balancing sales of 233,000 MWh, costing the system $6.3 million.[18]

In CUB's Opening testimony, CUB argued that in theory entering a market with more resources that had little to no marginal cost of dispatch would increase short-term sales. While the Company's Response Testimony denies this, the GRID run that is discussed in their Opening Testimony confirms it. Adding significant new renewable generation increases balancing sales.

Q. Does CUB have a recommendation for the treatment of Market Caps?

A. Yes. First, CUB recommends that the Commission reject PacifiCorp's proposal to return to the methodology that was rejected in 2012. There are several reasons to reject this:

- When looking at the margin (revenue gained and production cost) generated from short-term firm and balancing sales, the problem is much smaller than the Company is suggesting.

---

[18] UE 390 – PAC/100/Webb/29.

- A similar error occurs when forecasting market purchases. However, this is an over forecast of costs, not of sales margin, so it flows in the other direction and offsets the lost margin on short-term firm and balancing sales.
- The addition and expansion of EIM has trade-offs with market sales, which makes it harder to draw conclusions from historical trends.
- There has been a dramatic change in the Company's resource base which is expected to increase balancing sales but is not reflected in the historical nature of the Market Caps the Company is proposing.

CUB has examined a good deal of historical data and looked for trends that would allow us to set a market cap that is forward looking and accounts for the change in the Company's generation. Based on the data that is available and the different factors that impact sales, we have found it difficult to identify a methodology that will generally work on an ongoing basis. Next year, PacifiCorp will move to a new power dispatch model that should have greater capability and may provide greater opportunities to accurately model both short-term sales and purchases.

At the same time, CUB acknowledges that short-term firm and system balancing sales have been under-forecasted in the TAM. CUB is concerned that this leaves two options on the table: PacifiCorp's approach which returns to a methodology that the Commission rejected as too restrictive or continue with a methodology that has proven itself to be too expansive. CUB recommends a third option. For each marketing hub, the Company should set the cap at the mid-point between the restrictive (average of averages) approach and the expansive (maximum of averages) approach.

III. COAL ISSUES

1. Jim Bridger Unit 1

Q. PacifiCorp's Reply Testimony claims that following CUB's recommendation to allow GRID to economically cycle the Jim Bridger Unit 1 would seriously limit PacifiCorp's ability to provide safe and reliable service.[19] Do you agree?

A. No. PacifiCorp's response was a little over the top. It accuses CUB's proposal of limiting the Company's ability to provide safe and reliable service.[20] It claims CUB is trying to dictate actual operations of the Company's generation fleet.[21] It also says that because the (begin Confidential) [redacted] (end Confidential) would not be a good use of resources.[22] According to the Company, on the one hand, CUB's proposal is so significant it could undermine reliability. On the other hand, it is so insignificant that it should not even be modeled.

Q. Do you agree with the Company that CUB's proposal "seek[s] to predetermine how PacifiCorp should operate its system"[23]?

A. No. CUB's proposal seeks to understand more about the economic viability of the Company's simulated dispatch in the GRID forecast. If more economic alternatives

---

[19] UE 390 – PAC/400/Staples/17.
[20] UE 390 – PAC/400/Staples/17.
[21] UE 390 –PAC/400/Staples/40.
[22] UE 390 –PAC/400/Staples/40.
[23] UE 390 – PAC/400/Staples/17.

exist than the prevailing GRID forecast, they should be explored. The Company has an obligation to operate its system efficiently, both to provide service to customers and maximize value for shareholders.[24] CUB's proposal seeks to find whether there is a lower cost *simulated* dispatch under the normalized conditions used in the TAM forecast. If there is, it should inform the Company's operation of the plant, but the plant operation will vary from the TAM forecast due to non-normalized conditions. CUB's proposal furthers the purpose of the TAM[25] by exploring dispatch alternatives that may be both more accurate and lower cost.

Q. What did CUB propose for Jim Bridger, Unit 1?

A. CUB proposed two changes to GRID as it relates to Jim Bridger, Unit 1. First, CUB proposed the unit be allowed to economically cycle – temporarily shut down based on economic conditions. Second, CUB called for a GRID study to look at (begin Confidential) [redacted] (end Confidential). CUB believes that the IRP has raised significant questions concerning the economics of Jim Bridger, Unit 1. CUB believes the Commission could benefit from seeing how GRID models the unit when given the freedom to economically cycle the unit generally and to see whether there are economic benefits (begin Confidential) [redacted] (end Confidential). It is important to note that we were making a proposal for GRID analysis under normalized conditions. CUB was not proposing changes in actual operations with non-normalized conditions.

[24] *See, e.g,* UE 390 – PAC/400/Staples/17, lines 9-10 ("PacifiCorp has an obligation to operate its system to ensure that its customers receive safe and reliable service.").

Q. What were the questions that grew out of the IRP?

A. The IRP Action Plan acknowledged by the Commission included a proposal to retire Jim Bridger Unit 1 by the end of 2023.[26] The IRP examined closing coal plants in 2022. First, on an individual basis, and then examined closing multiple coal plants (stacked retirement cases). In an April 25, 2019 update to the Commission, the Company stated that its analysis showed "the greatest customer benefits are associated with an accelerated retirement of certain units at the Naughton and Jim Bridger power plants."[27] At that meeting, the Company presented ten stacked retirement cases showing customer benefits from 2022 coal plant retirement. All but one of those cases retired Jim Bridger 1.[28] PacifiCorp agrees that the IRP modeling actually found an (begin Confidential) [redacted] (end Confidential). However, the IRP coal analysis never looked at the economic benefits associated with closing coal plants before the end of 2022. The acknowledged action plan proposed an end of year 2023 closure date.

CUB believes that the IRP has raised questions as to whether customers are better off with Jim Bridger Unit 1 operating in 2022 and 2023. It stands to reason that the IRP may have demonstrated that an earlier closure was economical if its parameters were expanded to include earlier years. Given this, CUB believes that allowing

[26] OPUC Order No. 20-186 at 5.
[27] LC 70 – 2019 Integrated Resource Plan (IRP) Updated Coal Analysis Presented at the April 25, 2019, Public Meeting, page 2. https://edocs.puc.state.or.us/efdocs/HAD/lc70had135944.pdf
[28] LC 70 – 2019 Integrated Resource Plan (IRP) Updated Coal Analysis Presented at the April 25, 2019, Public Meeting, page 2. https://edocs.puc.state.or.us/efdocs/HAD/lc70had135944.pdf
[29] UE 390 – PAC/400/Staples/38.

GRID to economically cycle the plant makes sense. That way, when running the plant benefits customers, it would operate. When running the plant does not benefit customers, it would not.

CUB recognizes that the GRID model is different than IRP modeling. GRID is a model that simulates the dispatch of resources under normalized circumstances, whereas the IRP is a stochastic model that includes non-normalized results, looks at a 20-year planning horizon and allows for replacement resources beyond market purchases.

If PacifiCorp follows the IRP Action Plan, Jim Bridger, Unit 1 will close in two years. Until then, customers are being asked to pay millions of dollars to operate the plant, but there is little evidence to show that operating the plant provides benefits to customers. Allowing the plant to cycle when it is not economical will ensure that customers are only paying for prudent, economical dispatch. Doing a study that (begin Confidential) [redacted] (end Confidential) would provide additional information about the economical operation of the plant and might inform how we develop transition plans as coal is phased out of Oregon ratemaking.

Q. Can you explain the distinction you are making about normalized versus actual operations?

A. Yes. It is important to recognize that CUB is not making a proposal related to the actual operations of the plant. The purpose of the TAM is to forecast power costs based on prudent operation of the utility under normalized circumstances. Actual operations by the Company reflect real conditions. While CUB suggested that economically cycling of Jim Bridger 1 should increase in actual operations if it is found to be more economical,[30] CUB was not suggesting that the Company ignore real world conditions and blindly follow the normalized dispatch forecast in the TAM. For example, PacifiCorp's criticism of CUB's proposal refers to "historically bad" hydro conditions and "particularly low" spring runoff in actual 2021 operations.[31] The 2021 TAM modeled normalized conditions, including normal hydro and normal run off. Undoubtedly, due to the non-normal conditions, the Company is dispatching its resources in a manner that is not entirely consistent with the 2021 TAM. CUB agrees with the Company that non-normalized events will affect the dispatch of plants. But that does not mean that the TAM should not reflect prudent operations under normalized circumstances.

Q. After reading PacifiCorp's Reply Testimony, has CUB's proposal changed?

A. No. CUB continues to recommend that PacifiCorp allow GRID to economically cycle Jim Bridger, Unit 1 and believe that there is value in examining a GRID run with (begin Confidential) [redacted] (begin Confidential).

2. Huntington Coal Supply Agreement

Q. In Opening Testimony, CUB argued that PacifiCorp should consider terminating its Huntington Coal Supply Agreement (CSA). Staff proposed

[30] UE 390 – CUB/100/Jenks/16.
[31] UE 390 –PAC/400/Staples/39.

removing the minimum take requirement. PacifiCorp opposed both CUB and Staff proposals. What is your reaction to Staff's and PacifiCorp's positions?

A. CUB understands Staff's position. Their analysis shows that the minimum take provisions of the CSA are causing uneconomical dispatch of the plant and Staff is therefore proposing disallowing the costs associated with this uneconomical dispatch. CUB cannot support this proposal because CUB has testified that the CSA was prudent at the time the Company entered that agreement.[32] Disallowing costs associated with a prudent contract is not something CUB would generally propose.

But at the same time, CUB believes that there may be an opportunity to terminate the contract and sign a new contract that is appropriately sized. When the Company brought the contract forward for prudency review, it argued that the contract contained "broad termination rights" relating to environmental laws and regulations.[33] In Reply to our Opening Testimony, the Company agrees that there are broad termination rights in the Huntington CSA contract, but argues that current circumstances do not meet the necessary threshold for termination.

Q. How do you respond to the Company's testimony?

A. CUB and the Company agree that the contract has broad termination rights. These rights were essential to CUB's decision to deem the original contract prudent. Based on representations made at that time, CUB believes a case can be made that environmental laws and regulations are making operations at the plant

---

[32] UE 390 – CUB/100/Jenks/14.
[33] UM 1712 – PacifiCorp Application for Approval at 9-10.

uneconomical. CUB acknowledges that terminating a contract is a serious action. However, the Company has a responsibility to manage the contract prudently, including the termination clause.

It has been clear since the Company brought the contract forward that interpretation of the termination clause has broad implications. The contract was reviewed as part of the docket that closed the Deer Creek mine. There, CUB and Sierra Club both raised concerns about this CSA. Specifically, CUB said that the prudency of the contract "largely rests on the interpretation of the Environmental [termination] clause"[34] and whether it allowed termination only in the circumstance when environmental laws or regulations directly impacted operations of a coal plant or whether they allowed contract termination when environmental regulations made the operation of the plant uneconomical.

In that docket, PacifiCorp responded to our concerns by saying that because "the Company can exercise its termination rights if it becomes uneconomical to burn coal at Huntington, there is no incentive to continue burning coal when it is uneconomical to do so.[35]"

CUB believes that there is a strong argument here that the CSA is incenting operation during uneconomical times. The minimum take provisions in the contract require the plant to operate uneconomically. According to Staff, removing the

[34] UM 1712 – CUB/100/Jenks-McGovern/10.
[35] UM 1712 – PAC/500/Crane/7.

minimum take provisions would save customers (begin Confidential) [redacted] (end Confidential).[36] New environmental laws in multiple states have required utilities to increase their investment in renewables, which is making burning coal at the minimum levels in the contract uneconomical. There are several studies that demonstrate that state mandates for renewable energy add zero marginal cost resources to the grid, depress prices in wholesale markets, and lower market prices. This makes coal generation less economical. The National Renewable Energy Laboratory (NREL) found that the addition of "near zero marginal cost wind and solar generators" suppress energy prices and reduce the generation from conventional (fossil fuel) generation.[37]

Lawrence Berkeley National Lab (LBL) worked with NREL on an analysis that shows that renewable resources reduce wholesale electric prices.[38] The Regulatory Assistance Project's (RAP) new cost allocation manual states that the "addition of renewable resources depresses marginal energy costs by adding energy with zero fuel costs (or even negative costs in the case of wind energy with the production tax credit)."[39] Several studies that simulate the impact of renewables in various wholesale markets demonstrate that renewables reduce wholesale market prices.[40]

---

[36] UM 390 – PAC/400/Staples/44.

[37] Marginal Cost Pricing in a World without Perfect Competition: Implications for Electricity Markets with High Shares of Low Marginal Cost Resources, Michael Milligan, Bethany Frew, Kara Clark, and Aaron Bloom. National Renewable Energy Laboratory, December 2017, page v-vi.

[38] A Retrospective Analysis of the Benefits and Impact of U.S. Renewable Portfolio Standards, Ryan Wiser, Galen Barbose, Jenny Heeter, Trieu Mai, Lori Bird, Mark Bolinger, Alberta Carpenter, Garvin Heath, David Keyser, Jordan Macknick, Andrew Mills, and Dev Millstein, Lawrence Berkeley National Lab and National Renewable Energy Lab, January 2016.

[39] Electric Cost Allocation For a New Era, Jim Lazar, Paul Chernick and William Marcus, Regulatory Assistance Project, January 2020.

[40] For example, see Simulating the Interaction of a Renewable Portfolio Standard with Electricity and Carbon Markets, Mark C. Thurber, Trevor L. Davis and Frank A. Wolak, The Electricity Journal, 2015.

If wholesale prices were higher, the plant could operate more often and meet the minimum take provisions.

Q. Does the Company disagree with this?

In its Response Testimony in this docket, the Company states:

> While new environmental regulations have been enacted, like SB 1547, that could possibly have an effect on the economics of the plant, the Company is unaware of any environmental regulation with an indirect connection to the plant where an adverse effect upon the plant's economics could be substantiated.[41]

The Company's argument seems to be it cannot substantiate that environmental requirements, including the requirements to invest in renewables, have impacted the plant's economics. Ultimately, the interpretation of this clause and the evidence that would be required to substantiate termination is a legal issue, which CUB will appropriately address in briefing.

Q. Please explain why you said that terminating a contract is a serious issue?

A. Terminating a contract does create some risks. The counterparty to the contract might disagree that the termination is consistent with the contract and could challenge the termination, adding legal costs and legal uncertainty. PacifiCorp would have to negotiate a new contract with a lower minimum take requirement, but that could affect the price of the coal. And those risks have to be weighed against the value of termination, which in this case is (begin Confidential) [redacted] (end Confidential).[42]

Q. Has CUB's recommendation on this issue changed?

A. No. In Opening Testimony CUB recommended:

---

[41] UE 390 – PAC/600/Ralston/28
[42] UE 390 – PAC/400/Staples/44.

> CUB believes that the Company should conduct an analysis to determine whether the contract is leading to uneconomic dispatch of the plant, whether that is related to new environmental laws and regulations and whether it is in customers' interests to invoke the contract termination provisions.[43]

Essentially, CUB is asking that the Company prudently manage the termination clause. Today, the risks associated with contract termination may not be worth the value of such termination. But that may change. The ability of the Company to make the case that environmental laws and regulations have led to uneconomical dispatch under the contract may increase. The economic consequences of the minimum take provisions may grow. The contract termination clause was an essential element of CUB recommending that the contract was prudent and it should not be ignored. It should be evaluated regularly and managed prudently.

IV. 2023 TAM

Q. PacifiCorp opposes CUB's recommendation to file the TAM on January 15th. How do you respond?

A. CUB's concern is that next year's TAM will use AURORA to forecast power costs instead of GRID and this change will require more time for intervenors to understand the modeling. PacifiCorp argued that an earlier start date was not necessary because it was offering to conduct workshops to help parties understand, and January 15 was too early and would not allow the Company to use its December 31st forward price curve.[44]

---

[43] UE 390 –CUB/100/Jenks/16
[44] UE 390 – PAC/400/Staples/95

CUB believes that while workshops are helpful, many questions and concerns will come out of using the AURORA model and seeing the results. Workshops simply are not a substitute for an analyst immersing themselves in the filing--the Company's full modeling, including inputs, results, and workpapers. Because of the dates associated with direct access offering, there is not the option to extend the TAM proceeding if more time is necessary.

CUB does understand that a filing on January 15th would make it impossible for the Company use its most updated information. Therefore, CUB is revising its proposal:

- The Company should file its TAM on March 1, 2022, or before then if practicable. In years with General Rate Case years, the TAM is filed on March 1, so we know that the updated data is available by that date.
- To help parties move quickly in reviewing the 2023 TAM, the docket and protective order should be pre-established, and parties should have access to and training on how to use AURORA before the filing is made. The workshop should address AURORA modeling using real, rather than illustrative, figures from the Company's filing.

V. ALLOCATION OF EIM BENEFITS

Q. In Reply Testimony PacifiCorp changed the allocation factor applied to EIM benefits. Does CUB support this change?

A. No. PacifiCorp changed the allocation of EIM benefits from System Generation to System Energy because of a decision by the Wyoming Public Service

Commission. CUB believes allowing one state regulatory commission to make a decision that is then applied to all six jurisdictions is a bad precedent and it is why interstate cost allocation is normally negotiated through the Multi-State-Process (MSP). In addition, the EIM benefits should properly be allocated as System Generation, so the customers who are paying for the underlying plants that are dispatched receive the benefits from that plant.

Q. Please explain why this is a bad precedent?

A. Switching from System Generation to System Energy may well create additional benefits for Wyoming customers. Because allocation factors are allocating real costs or benefits, a change in factors inherently shifts costs or benefits from one state to another. If all states began changing allocation factors when there was a chance to reallocate costs or benefits in their favor, then PacifiCorp will find it nearly impossible to create a common agreed upon system and the Company will likely end up under recovering costs or over suppling benefits. This is why there has been work to develop a series of agreements between the states concerning the allocation of costs and benefits. That process will be undercut if Wyoming is allowed to dictate a new allocation onto other states. PacifiCorp's proposal that all other states should agree to go along with Wyoming's decision sets a terrible precedent that will only encourage states to go their own way on allocation issues.

Q. Why should EIM benefits properly be allocated to generation?

A. System generation is an allocation factor that is used to allocate the investment cost of a generation asset. In essence it represents an ownership share. System Energy is how we allocate the variable costs of using the plant. In essence it represents the use of the plant. The reason these are different is that we plan and build the capacity we need to serve load and allocate that based on the capacity needs of each state. It is necessary to have enough capacity to meet winter and summer peak loads, so states with higher peak loads will be assigned a greater capacity allocation. Each state has the capacity necessary to meet its peak load. A good analogy would be if two roommates decided to buy a car to share and split the car payment 50/50. Between them one car would be enough to meet their needs and by sharing a car, they each have ½ the car payment they would otherwise have. But they each use the car differently. One roommate uses the car for semi-regular trips to Seattle and the other one just uses it to get around town. Because of these use patterns, they each pay for their own share of gas, rather than split it. Assume a friend comes along and wants to rent the car for the weekend and will pay $100 for the rental. I would argue that the rental income should be allocated based on the share of the ownership costs (car payments) not the share of usage costs (gasoline).

Q. What is your recommendation on PacifiCorp's proposal to change EIM benefit allocations?

A. It should be rejected.

VI. CONSUMER OPT-OUT CHARGE (COOC)

Q. Please summarize this issue.

A. In Opening Testimony, Calpine Energy Solutions, LLC. (Calpine) proposed to enable PacifiCorp's Consumer Opt-Out Charge (COOC) to produce a negative value, which would credit direct access (DA) customers who choose to leave the

Company's system during the November open enrollment window.[45] In response, PacifiCorp argued that the COOC is intended to prevent cost-shifting in the administration of its long-term DA program, and setting the charge as a negative number, rendering it a credit, "would fundamentally be at odds with its purpose."[46] CUB agrees with the Company's position. The COOC is an important component of the Company's DA program that serves to protect non-participating cost of service customers from unwarranted cost shifting.

Q. What does the Commission say about the COOC?

A. PacifiCorp's COOC was adopted in Commission Order 15-060 in Docket No. UE 267. There, the Commission concluded "that the [COOC] is necessary pursuant to implementation of the state's direct access laws by our rules. The inclusion of an opt-out **charge** is consistent with our request that PacifiCorp design a five-year opt-out program that would protect others from cost-shifting."[47] There, the Commission adopted the COOC "as it was presented in modified form by PacifiCorp in Reply Testimony."[48]

Q. How did PacifiCorp present the COOC in that proceeding?

A. PacifiCorp was clear that the COOC was designed to be a charge. It argued that elimination of the COOC was contrary to Oregon DA laws and regulations.[49] According to PAC, the COOC is necessary to minimize cost-shifting to nonparticipating customers.[50] The Commission agreed.

---

[45] *See* UE 390 – Calpine Solutions/100/Higgins/20, lines 10-16.
[46] UE 390 – PAC/900/Meredith/4.
[47] *In re PacifiCorp, dba Pacific Power, Transition Adjustment, Five-Year Cost of Service Opt-out,* OPUC Docket No. UE 267, Order No. 15-060 at 6 (Feb. 24, 2015) (emphasis added).
[48] *Id*.
[49] UE 267 – PAC/400/Duvall/3, lines 9-10.
[50] UE 267 – PAC/300/Steward/3, lines 5-7.

Q. Why is it important that a charge like a COOC be in place to protect nonparticipating customers from cost-shifting that may result from PAC's CA program?

A. I am not an attorney, and CUB will appropriately respond to the legal components of this issue in briefing. However, my understanding is that Oregon's DA laws, specifically ORS 757.601(1), provide that DA may not cause the unwarranted shifting of costs to other customers. Beyond the Commission's strict prohibition on unwarranted cost-shifting from implementation of the DA program, there are also unresolved policy questions that inform this issue.

Q. Please explain.

A. The Commission has opened a proceeding to investigate issues related to long term DA programs, including, but not limited to, whether their implementation is or has resulted in the unwarranted shifting of costs to nonparticipating customers. In that proceeding, UM 2024, CUB submitted comments arguing that the DA program, as currently implemented, is already resulting in the shifting of costs from DA program participants to nonparticipating cost-of-service customers.[51] For example, DA program participants purchase energy on the wholesale market at marginal values that do not capture the capital costs associated with the underlying generating plant.[52] When investor-owned utilities sell renewable energy into wholesale markets at its marginal cost, the captive customers of the utility are paying the capital costs for a resource that eventually serves—and benefits—a DA customer. This subsidization is commonplace, is cost-shifting, and is a core issue

[51] UM 2024 – CUB's Opening Comments at 5-9 (Mar. 16, 2020).
[52] *Id.* at 5-6.

that must be addressed in UM 2024. Other examples include the shifting of costs associated with state and federal mandates, net metering and community solar, coal plant closure and decommissioning, demand response, energy efficiency, and PURPA development.[53]

Q. Why is that relevant here?

A. If the COOC is allowed to go negative, as Calpine is proposing, it would exacerbate an existing issue. CUB believes there is already cost-shifting occurring in the operation of PacifiCorp's DA program. Again, while I am not a lawyer, this appears to be in contravention of Oregon's DA laws that prohibit the unwarranted shifting of costs to nonparticipating customers.[54] Oregon's DA program was designed to enable a subset of customers to choose to procure their energy needs through the market. It is imperative that the choices of the customers that are able to pursue different avenues to meet their needs not negatively impact the utility's captive customers that have no choice.

Q. Calpine argues that the COOC should be allowed to swing negative and become a credit if market conditions allow for it. How do you respond?

A. CUB disagrees with Calpine. While Calpine would prefer to narrow the scope of the calculation of the COOC to its applicability in this proceeding, potentially allowing the COOC to swing negative implicates a broader, unresolved policy dispute. Cost-shifting is already occurring as a result of Oregon's DA program. Enabling the COOC to swing negative would result in further subsidization of DA

[53] *Id*. at 5-9.
[54] ORS 757.601(1).

customers from captive customers.[55] Further, CUB, Calpine, and other parties have previously agreed to address similar policy issues related to cost-shifting and the DA program in the UM 2024 proceeding.

Q. Please explain.

A. In UE 374, PacifiCorp's last general rate case, CUB proposed to make coal plant closure and decommissioning costs non-bypassable so that DA customers would also be liable for the costs of transitioning the Company's system off coal. Although CUB knew this was only one policy issue in a larger debate about DA and cost-shifting, CUB felt it was appropriate because coal plant decommissioning was a live issue in UE 374.

Q. How was this issue resolved?

A. CUB, Calpine, and other parties all agreed to address the issue in the UM 2024 long term DA investigation.[56] According to Calpine, the issue was most appropriately addressed in that proceeding "because it implicates significant direct access policy issues that should be addressed in a wholistic manner."[57]

Q. Does enabling the COOC to go negative implicate significant DA policy issues?

A. Yes. As discussed, there is already cost-shifting occurring as a result of PacifiCorp's DA program. Before enabling PacifiCorp's COOC to go negative, exacerbating this issue, it is essential for the Commission to determine the extent of the cost-shifting that is occurring. That investigation is occurring within the bounds of UM 2024. Enabling the COOC to go negative during such uncertainty is

---

[55] *See* UE 390 – PAC/900/Meredith/4-5.
[56] *See* UE 374 – CUB's Prehearing Brief at 19 and UE 374 – Calpine's Post-Hearing Opening Brief at 3.
[57] UE 374 – Calpine's Post-Hearing Opening Brief at 3.

poor policy. Calpine attacks the Company's rationale for maintaining the COOC as a charge and says the Company "cannot have it both ways."[58] Calpine cannot have it both ways either—it cannot reasonably argue that one issue related to cost-shifting is a broad policy issue that must be addressed in UM 2024 while another must be resolved in this proceeding.

Q. What is CUB's recommendation?

A. CUB recommends that the Commission reject Calpine's proposal to enable the COOC to become a credit for DA customers. The Commission should adopt PacifiCorp's proposal to set the COOC to zero if its value becomes negative. Then, broader policy issues related to cost-shifting within Oregon's DA program can be addressed in UM 2024. Once Oregon's DA program captures the full suite of costs that are currently being shifted from DA customers to captive customers, changes to the calculation of the COOC may be considered. Until that time, it is inappropriate for cost-of-service customers to further subsidize DA customers.

VII. CONCLUSION

Q. Can you summarize CUB's recommendations?

A. Yes. CUB makes the following recommendations:

- **Market Caps**. The limitation of market capacity should be established by setting a market cap at the mid-point between the restrictive (average of averages) approach and the expansive (maximum of averages) approach.

[58] UE 390 – Calpine Solutions/Higgins/17, lines 15-16.

- **Jim Bridger, Unit 1**. CUB recommends that PacifiCorp allow GRID to economically cycle Jim Bridger, Unit 1 and that the Company should produce a GRID run with (begin Confidential) [redacted] (begin Confidential).

- **Huntington CSA.** |CUB is not recommending a disallowance for Huntington coal costs. However, CUB is recommending that the Company prudently manage the Contract Termination Provisions.

- **2023 TAM.** CUB is recommending that the Company be required to file its 2023 TAM by March 1, 2022; that the docket and protective order should be preestablished; that parties should have access to the AURORA before the filing is made; that workshops should address AURORA using real, rather than illustrative figures.

- **Allocation of EIM Benefits**. CUB is recommending that the Commission reject the Company's proposal to change the allocation of EIM benefits from System Generation to System Energy.

- **Consumer Opt-Out Charge.** CUB recommends that the Commission reject the proposal to allow the COOC to become a credit for direct access customers.

Q. Does this conclude your testimony?

A. Yes.

UE 390– CERTIFICATE OF SERVICE

I hereby certify that, on this 30th day of June, 2021, I served the **Confidential Rebuttal and Cross-Answering Testimony Comments of the Oregon Citizens' Utility Board** in docket UE 390 upon the Commission and each party designated to receive confidential information pursuant to Order 16-128 through a secure, encrypted attachment to an e-mail.

AWEC	
BRENT COLEMAN **(C)** **(HC)** DAVISON VAN CLEVE, PC	1750 SW HARBOR WAY, SUITE 450 PORTLAND OR 97201 blc@dvclaw.com
JESSE O GORSUCH **(C)** **(HC)** DAVISON VAN CLEVE	1750 SW HARBOR WAY STE 450 PORTLAND OR 97201 jog@dvclaw.com
TYLER C PEPPLE **(C)** **(HC)** DAVISON VAN CLEVE, PC	1750 SW HARBOR WAY STE 450 PORTLAND OR 97201 tcp@dvclaw.com
CALPINE SOLUTIONS	
GREGORY M. ADAMS **(C)** RICHARDSON ADAMS, PLLC	PO BOX 7218 BOISE ID 83702 greg@richardsonadams.com
KEVIN HIGGINS **(C)** ENERGY STRATEGIES LLC	215 STATE ST - STE 200 SALT LAKE CITY UT 84111-2322 khiggins@energystrat.com
OREGON CITIZENS UTILITY BOARD	
MICHAEL GOETZ **(C)** **(HC)** OREGON CITIZENS' UTILITY BOARD	610 SW BROADWAY STE 400 PORTLAND OR 97205 mike@oregoncub.org
ROBERT JENKS **(C)** **(HC)** OREGON CITIZENS' UTILITY BOARD	610 SW BROADWAY, STE 400 PORTLAND OR 97205 bob@oregoncub.org
PACIFICORP	
AJAY KUMAR **(C)** **(HC)** PACIFIC POWER	825 NE MULTNOMAH STE 800 PORTLAND OR 97232 ajay.kumar@pacificorp.com
SBUA	

DIANE HENKELS **(C)** SMALL BUSINESS UTILITY ADVOCATES	621 SW MORRISON ST. STE 1025 PORTLAND OR 97205 diane@utilityadvocates.org
DARREN WERTZ **(C)** SMALL BUSINESS UTILITY ADVOCATES	wertzds@gmail.com
SIERRA CLUB	
ANA BOYD **(C)** **(HC)** SIERRA CLUB	2101 WEBSTER ST STE 1300 OAKLAND CA 94612 ana.boyd@sierraclub.org
THIEN CHAU **(C)** **(HC)** SIERRA CLUB	thien.chau@sierraclub.org
ROSE MONAHAN **(C)** **(HC)** SIERRA LCU	2101 WEBSTER ST STE 1300 OAKLAND CA 94612 rose.monahan@sierraclub.org
STAFF	
MOYA ENRIGHT **(C)** **(HC)** PUBLIC UTILITY COMMISSION OF OREGON	PO BOX 1088 SALEM OR 97308 moya.enright@state.or.us
SCOTT GIBBENS **(C)** **(HC)** PUBLIC UTILITY COMMISSION OF OREGON	201 HIGH ST SE SALEM OR 97301 scott.gibbens@puc.oregon.gov
SOMMER MOSER **(C)** **(HC)** PUC STAFF - DEPARTMENT OF JUSTICE	1162 COURT ST NE SALEM OR 97301 sommer.moser@doj.state.or.us

Thomas Jerin
Legal Assistant / Office Manager
Oregon Citizens' Utility Board
610 SW Broadway, Ste. 400
Portland, OR 97205
503.227.1984
dockets@oregoncub.org