McDowell
Rackner &
Gibson PC

KATHERINE MCDOWELL
Direct (503) 595-3924
katherine@mcd-law.com

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PO Box 1088
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Re: UE 296– In the Matter PACIFICORP, dba PACIFIC POWER, 2016 Transition Adjustment Mechanism

Attention Filing Center:

Attached for filing in the above-captioned docket is an electronic copy of PacifiCorp's Reply Brief.

Please contact this office with any questions.

Very truly yours,

Katherine McDowell

cc: Service List

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

In the Matter of PACIFICORP, dba PACIFIC POWER 2016 Transition Adjustment Mechanism	**UE 296**

PACIFICORP'S REPLY BRIEF

October 5, 2015

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In the Matter of: PACIFICORP, dba PACIFIC POWER 2016 Transition Adjustment Mechanism	**PACIFICORP'S REPLY BRIEF**

I. INTRODUCTION

PacifiCorp d/b/a Pacific Power (PacifiCorp or Company) respectfully submits this Reply Brief to the Public Utility Commission of Oregon (Commission). The central issues in this case concern the Company's proposals to increase the accuracy of its net power costs (NPC) forecast in the Transition Adjustment Mechanism (TAM). The importance of these proposals was recently highlighted in a concurrent case, docket UM 1662, involving the NPC-related costs of compliance with Oregon's renewable portfolio standard (RPS). In opposing recovery of these costs outside of a Power Cost Adjustment Mechanism (PCAM), Staff exhorted the utilities to improve their NPC modeling to better capture their actual costs in base rates:

> Staff recommends the utilities work on developing improved generation production forecasting methodologies to address their risk to under-collect [NPC]. The PCAMs allow each company to recover in rates 100% of the utilities' forecasted costs if the forecasts are accurate and correctly reflect actual costs. It is when the forecast of power costs is in error that the company under-collects. Therefore, improving the accuracy of forecasts will limit the potential that utilities will not fully recover their power costs.[1]

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[1] *Re Portland General Electric Company and PacifiCorp Request for Generic Power Cost Adjustment Mechanism Investigation*, Docket No. UM 1662, Staff's Prehearing Brief at 8 (Sept. 16, 2015).

Precisely as Staff recommended, in this case PacifiCorp developed and presented "improved generation production forecasting methodologies to address [its] risk to under-collect [NPC]," most notably through its system balancing proposal. Unfortunately, the parties (including Staff) all oppose the Company's system balancing proposal; Staff and the Industrial Customers of Northwest Utilities (ICNU) oppose certain other NPC modeling improvements; and the Citizens' Utility Board of Oregon (CUB) goes so far as to argue that the design of the PCAM actually precludes the Company's system balancing proposal in the TAM.

As outlined below, the system balancing proposal and the Company's other modeling improvements are fully consistent with the Commission's approach toward NPC recovery in the TAM and the PCAM. The modeling changes are supported by significant analysis and evidence, most of which is substantively unrebutted. The implementation of these changes would produce a relatively modest rate increase of approximately $12.4 million, or 1.0 percent overall.[2] Delay or rejection of these proposals will perpetrate PacifiCorp's persistent under-recovery of NPC, thwarting the goal of better alignment between forecast and actual NPC.

As Staff indicated in docket UM 1662, "improving the accuracy of forecasts will limit the potential that utilities will not fully recover their power costs." And, as CUB stated in that same docket, "[i]f forecasted rates [are] based on strong analysis and modeling of power costs, then rates are fair and reasonable, and customers are not harmed by paying these rates…."[3] Adoption of PacifiCorp's proposals in this case will produce rates that are fair and

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[2] PAC/500, Dickman/5. This forecast is subject to a final update in November 2015.

[3] Docket No. UM 1662, CUB's Prehearing Brief at 14 (Sept. 16, 2015).

reasonable, while taking an important step toward mitigating PacifiCorp's decade-long under-recovery of NPC in Oregon rates.

II. ARGUMENT

A. PacifiCorp's System Balancing Proposal Should be Adopted in the 2016 TAM.

1. Contrary to CUB's Position, the Current Design of the PCAM Makes NPC Modeling Improvements like the System Balancing Proposal Imperative in the TAM.

On page 3 of its Response Brief, CUB states:

> Although this is a TAM proceeding, considering the entire context of rate recovery for net power cost (NPC) is important to the evaluation of the Company's system balancing proposal. As stated by the Company, "[t]he goal of the TAM is to forecast the actual NPC the Company expects to incur during the test period as accurately as possible."[4]

PacifiCorp agrees with this statement, which supports the Company's system balancing proposal. Under the Commission's current approach to NPC, cost recovery occurs primarily—and in most cases, exclusively—through the TAM. PacifiCorp's PCAM operates as a backstop only in extreme cases. This means that the accuracy of the TAM is of paramount importance, and the Commission's expectation is that the TAM should "produce the best possible estimates of all components of net power costs."[5] Under the current NPC recovery paradigm, material modeling improvements like the system balancing proposal are appropriate and necessary, especially upon evidence of PacifiCorp's chronic NPC under-recovery through the TAM.

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[4] CUB's Response Brief at 3.

[5] *Re PacifiCorp 2014 Transition Adjustment Mechanism*, Docket No. UE 245, Order No. 12-409 at 7 (Oct. 29, 2012).

CUB turns this around, arguing that because the PCAM disallows actual NPC recovery in most cases, PacifiCorp should not be allowed to "chip away at the PCAM design imposed by the Commission by shifting actual costs out of the PCAM and into the TAM."[6] CUB first claims (wrongly, as discussed below) that the system balancing proposal would allow PacifiCorp to recover non-normalized NPC; CUB then argues that recovery of these costs should not be allowed through the TAM because these costs are generally non-recoverable through the PCAM. The logic of CUB's argument—that the TAM and the PCAM should operate together to systematically and permanently exclude certain NPC components—is at odds with Commission precedent. Indeed, when rejecting the argument that PCAMs make annual NPC updates like the TAM irrelevant, the Commission specifically found that that PCAMs and annual updates must work in concert to ensure that utilities have the opportunity to recover all NPC and are subject to no more than normal business risk.[7] CUB's logic is also fundamentally inconsistent with general ratemaking principles allowing the Company an opportunity to recover all of its prudently incurred costs.[8]

2. CUB Wrongly Claims That the System Balancing Proposal Incorporates Non-normalized Hydro or Weather Conditions.

Based on a completely inaccurate representation of how the system balancing proposal operates, CUB argues that the proposal incorporates into the NPC forecast changes in market price and volume caused by weather or hydro conditions.[9] CUB claims that

[6] CUB's Response Brief at 4.
[7] *Re Portland Gen. Elec. Co.*, Dockets Nos. UE 181 et al., Order No. 07-015 at 18 (Jan. 12, 2007) (absent an annual update a utility "will be exposed to more than normal business risk: through application of the deadband, it will bear the net effect of both expected changes in power costs (up or down) and unpredictable variations in power costs throughout the year.").
[8] *Re Portland Gen. Elec. Co.*, Dockets Nos. DR 10, UE 88 & UM 989, Order No. 08-487 at 7 (Sept. 30, 2008) ("The Commission's ultimate goal is to set rates that provide the utility the opportunity to collect enough revenue to recover reasonable operating expenses and to earn a reasonable return on investments it has made to provide service.")
[9] CUB's Response Brief at 4-5, 13; CUB/100, Jenks-Hanhan/7.

increased market purchases due to poor hydro conditions would be reflected in future TAMs through the Company's proposed three-year average, which compares the actual prices of the Company's short-term transactions with the actual monthly average prices. CUB's arguments misrepresent the operation of the system balancing proposal in several respects.

First, the Company's system balancing proposal does not use historical market volumes to forecast future volumes. The Company's proposal uses historical data only to quantify the variance between PacifiCorp's actual, short-term transaction prices and the average monthly price. This variance is then used to refine the forward price curve to predict the cost of future system balancing transactions—under normal weather and hydro conditions—in the TAM test period.

Second, the Company's system balancing proposal does not add forecasted volumes to compensate for unusual weather or hydro variances. All of the volume calculations are based on the normal weather and hydro in GRID. The transaction volumes added to the Company's forecast reflect the fact that GRID determines a single transaction volume for each hour, whereas the Company must balance its system with a combination of monthly, daily, and hourly products.[10]

Third, the Company's system balancing proposal does not include true-ups of any kind, including a true-up for historical hydro volumes.[11] A true-up allows a utility to recover

[10] PAC/500, Dickman/21.

[11] CUB's Response Brief at 12-13 ("With regard to adjusting the forward market prices, CUB's objections have centered on the fact that it would fundamentally mix PCAM-style true-ups with TAM-style forecasts in a way that unfairly shifts risks (and potentially costs) onto customers."); CUB's Response Brief at 6 (system balancing refinement "would add a true-up of historic hydro volumes to the TAM," which CUB argues is "not consistent with the Commission's design criteria for cost-recovery of variations . . .").

(or refund) the difference between a forecast amount included in rates and the actual amount incurred, which does not occur in any way under the Company's proposal.[12]

In summary, CUB has presented no evidence that the Company's proposal is skewed by low or high hydro or weather conditions in the historical period, nor has CUB presented evidence indicating that the Company's system balancing costs would not occur under the normalized conditions used in the Company's NPC forecast.

3. The Company's System Balancing Proposal is Properly Normalized through Use of an Historical Average, Contrary to CUB's and ICNU's Claims.

Weather and hydro conditions are always expected to vary from the precise forecast included in GRID, even if the actual conditions are perfectly normal. For instance, the Company's load forecast has a range of high and low daily peaks in each month. And normal weather and hydro vary from monthly and daily operational forecasts, creating the need for balancing transactions even under normal conditions. The use of a multi-year average in the system balancing proposal is an established method for smoothing such variations to develop a normalized forecast.

CUB and ICNU argue that the proposal's use of historical data to forecast future volumes and prices is inconsistent with normalized ratemaking.[13] But neither can dispute that the Commission regularly uses historical averages to produce normalized forecasts and that the Commission has specifically incorporated historical market data, which is influenced by weather, into normalized forecasts—*e.g.*, to calculate an arbitrage trading credit,[14] to

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[12] *See* Order No. 08-487 at 39.

[13] CUB's Response Brief at 6; ICNU's Response Brief at 13.

[14] *Re PacifiCorp 2008 Transition Adjustment Mechanism*, Docket No. UE 191, Order No. 07-446 at 10-11 (Oct. 17, 2007).

calculate hourly scalars to refine the Company's forward price curve,[15] and to calculate caps to forecast market volumes.[16]

The Company's Opening Brief provided extensive Commission precedent for the use of historical averages to normalize forecasts.[17] CUB attempts to distinguish this precedent, but in doing so confirms the reasonableness of the Company's system balancing proposal.

First, CUB argues that the Commission previously rejected a margin adjustment for system balancing transaction in the 2008 TAM[18] because system balancing is influenced by weather and hydro conditions and therefore should not be forecast using historical averages.[19] On the contrary, the Commission rejected the system balancing adjustment because there was no evidence of a systematic cost or revenue associated with those transactions, and said nothing about weather or hydro conditions.[20] Furthermore, CUB's brief fails to note that the Commission expressed a willingness to adopt a system balancing adjustment if "there is a systematic bias in the way [GRID] treats" system balancing transactions.[21]

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[15] *Re PacifiCorp 2012 Transition Adjustment Mechanism*, Docket No. UE 227, Order No. 11-435 at 18-20 (Nov. 4, 2011).

[16] Order No. 12-409 at 7-8. In 1984, Staff issued a policy statement specifically recommending the use of historical data to forecast forced outage rates because a rolling average "reflects recent plant experience, which [] tends to better portray expected operation over the coming year." Dockets Nos. UE 180 and 181, Staff/100, Galbraith/5.

[17] PacifiCorp's Opening Brief at 9-12.

[18] In the 2008 TAM, the Commission adopted Staff's proposed arbitrage credit, but rejected its proposed system balancing credit. Both credits were calculated by truing-up prior forecasts of PacifiCorp's market activity with the actual results of its market activity. Docket UE 191, Staff/100, Wordley/6-7 (June 27, 2007).

[19] CUB's Response Brief at 9. CUB claims that in the 2008 TAM the Commission "declined to adopt an adjustment wherein historical transactions, influenced by weather and hydro conditions, were meant to balance load" when it rejected Staff's proposed adjustment to impute a margin related to the Company's system balancing transactions.

[20] Order No. 07-446 at 10-11.

[21] Order No. 07-446 at 11.

CUB also claims that in the 2008 TAM, the Company argued that Staff's margin adjustment violated normalized ratemaking by using historical market data to forecast NPC.[22] But Staff calculated its credit by *truing-up* historical differences between forecasts and actuals and then recovering that difference in future rates.[23] As noted above, there is no true-up in the Company's system balancing proposal.

Second, CUB attempts to distinguish the hourly scalars adopted in the 2012 TAM, which were calculated using historical data. CUB claims that the scalars were "simply used to shape hourly prices" included in the Company's normalized forward price curve.[24] But this is exactly what the Company's proposal does here—it creates a more accurate hourly price by shaping the normalized forward price curve.[25]

Third, CUB attempts to distinguish the use of historical data to normalize the Company's market caps.[26] Market caps and the volume component of the system balancing proposal rely on historical averages of actual transaction volumes to limit volumes at illiquid markets and reflect actual historical spot market volumes, respectively. Both adjustments use actual historical data that is influenced by "non-normalized weather and hydro conditions" and both adjustments normalize that historical data through a multi-year average.

Fourth, CUB claims that the use of historical averages to shape forecasted wind generation is distinguishable because the forecasted generation levels were not based on

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[22] CUB's Response Brief at 8.
[23] Docket UE 191, Staff/100, Wordley/6-7 (June 27, 2007).
[24] CUB's Response Brief at 9.
[25] Order No. 11-435 at 19 ("we find that the company has adequately explained that its use of hourly scalars is intended to develop results consistent with historical price data.").
[26] CUB's Response Brief at 10. Strangely, CUB justifies the use of historical data for market caps because it has always been used for market caps. It is unclear why it is appropriate to use historical data to normalize as long as it has always been done that way.

historical data.[27] The Company's system balancing proposal is used to shape the normalized forward price curve just like the historical generation shape was used to refine the forecast wind generation. Moreover, the Company has proposed in this case to use historical generation levels for forecast wind generation purchased from third parties and CUB has not objected. It is also notable that in the 2014 TAM, CUB argued that the Company should use three years of historical wind data to smooth out variations and produce a normalized generation profile.[28]

Fifth, CUB's concerns about the alleged lack of hydro normalization are overblown considering that CUB has supported Idaho Power's use of non-normalized hydro generation in its annual power cost updates for many years, effectively allowing Idaho Power to recover "actual" hydro costs through its annual power cost update.[29]

4. It is Irrelevant that the System Balancing Proposal is an Input to GRID, and Not Embedded in the GRID Model.

CUB also questions the accuracy of the GRID model and argues that the Company should have included the system balancing proposal within the model.[30] But the pricing component of the proposal refines the Company's forward price curve, which is itself an input to GRID.[31] Additionally, while it may be theoretically possible to incorporate the volume component into GRID, this possibility is no basis to reject the Company's proposal

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[27] CUB's Response Brief at 11.

[28] *Re PacifiCorp 2014 Transition Adjustment Mechanism*, Docket No. UE 264, Order No. 13-387 at 3 (Oct. 28, 2013)

[29] *Re Idaho Power Co. Application for Authority to Implement a Power Cost Adjustment Mechanism for Electric Service to Customers in the State of Oregon*, Docket No. UE 195, Order No. 08-238, Appendix A, Section 11(f) (Apr. 28, 2008). Idaho Power's annual update includes a component based on normalized hydro conditions (October Update) and a component based on the actual hydro conditions expected during the test year (March Forecast).

[30] CUB's Response Brief at 13.

[31] TR. 113-115 (Dickman).

in this case. At this point, it is more transparent and easier to analyze the proposal outside of GRID. Once it is approved, the Company can explore ways to incorporate it into the GRID model.

5. The Commission Should Reject Staff's Request to Delay Approval of the Company's System Balancing Proposal in this Case.

Staff reiterates that "it fundamentally agreed with PacifiCorp's goal of improving the GRID model" to better forecast system balancing prices and volumes.[32] Yet, Staff still recommends that the Commission defer any decisions in this case and instead open a generic investigation into the Company's system balancing proposal. A generic investigation is unnecessary. The Company presented robust analysis justifying its proposal and worked diligently with the parties to explain both the rationale for and mechanics of its proposal.[33] The record supports the Company's proposal and it should be approved now.

Staff argues that there was not enough time to fully understand and verify the Company's adjustment, given the voluminous data and complex formulas.[34] As an example, Staff points to the Company's response to Staff's data request 39, which included numerous Excel spreadsheets ranging in size from 22 megabytes (MB) to 63 MB. But while the data was voluminous, the results were straightforward. Staff's request asked for a 36-month breakdown of the historical NPC increase due to the difference between the day-ahead and hourly transactions and the historical average monthly market prices.[35] The Company's response provided the monthly breakdown, which was simply the difference between the Company's day-ahead and hourly transaction costs and the costs of those same volumes at

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[32] Staff's Response Brief at 4.
[33] PAC/500, Dickman/21-22.
[34] Staff's Response Brief at 4-5.
[35] Staff/105, Ordonez/4; PAC/100, Dickman/26.

the average monthly market prices. While it is true that the data underlying the calculations were voluminous (because Staff sought 36 months of historical data related to every day-ahead and hourly transaction), the results were not.

Moreover, in response to these concerns, the Company provided a supplemental response that included simplified calculations in a much smaller spreadsheet (two files that were 7 MB and 13 MB).[36] The Company's reply testimony also provided an example demonstrating how the adjustment works, using a subset of the data and simplified presentation, and with no changes in the calculations or results.[37]

Staff also claims that they were unable to corroborate the historical purchase and sales prices with the current GRID results.[38] But the Company's filing included a GRID run without the Company's adjustment, which showed system balancing costs of just $0.5 million per year, compared to the historical costs, which were $7.1 million per year.[39]

The Commission can acknowledge Staff's interest in further study of the system balancing proposal by approving it now while monitoring its results in the coming years. The Commission has previously taken this approach when adopting refined outage rate modeling and in adopting adjustments related to the Company's wholesale market activity.[40] Now that the Company has established that unrecovered system balancing costs are a source of its persistent under-recovery of NPC in Oregon, it is important to approve the Company's system balancing proposal without delay.

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[36] PAC/500, Dickman/21.
[37] PAC/500, Dickman/21; PAC/507, Dickman/1.
[38] Staff's Response Brief at 5.
[39] PAC/100, Dickman/28.
[40] *In the Matter of the Public Utility Commission of Oregon, Investigation into Forced Outage Rates*, Docket No. UM 1355, Order No. 10-414 at 7 (Oct. 22, 2010); Order No. 07-446 at 11.

6. ICNU's Conceptual Challenge to the System Balancing Proposal is Undermined by its Recognition That Timing Differences Can Produce System Balancing Costs.

ICNU challenges the Company's system balancing proposal based on its witness' unsupported opinion that the Company purchases and sales perfectly offset each other and are therefore cost neutral for PacifiCorp.[41] ICNU's theory was thoroughly debunked by PacifiCorp's expert Frank Graves, who explained that it fails to account for the correlation between demand and prices.[42] ICNU's theory is also irreconcilable with PacifiCorp's evidence of consistent price divergence between its short-term purchases and sales,[43] and ICNU's own admission in its testimony that it is "expected" that the weighted average purchase and sale prices will differ due to timing differences between when the Company is a buyer and seller.[44] The timing difference between purchases and sales to which ICNU refers is the foundation of the Company's system balancing proposal.[45]

The Company's purchases have historically been weighted toward higher priced periods within each month and sales toward lower priced periods. ICNU acknowledges that pricing will vary based on these timing differences and provides no method by which the Company could avoid those timing differences. Those differences are not reflected in the NPC forecast absent the Company's proposal.

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[41] ICNU's Response Brief at 3-4.
[42] PAC/600, Graves/6-9.
[43] *See, e.g.,* PAC/500, Dickman/16; PAC/600, Graves/6, 8.
[44] ICNU/100, Mullins/16.
[45] PAC/500, Dickman/14-16.

7. ICNU's Claim that the System Balancing Proposal Includes Hedging Costs is False.

ICNU claims that the Company's system balancing proposal includes hedging transactions because the Company's volume adjustment includes additional "monthly, daily, and hourly transactions."[46] ICNU fails to acknowledge that while the calculation of the volume of transactions includes "monthly, daily and hourly transactions," these transactions are fundamentally priced based on the Company's Official Forward Price Curve and historical system balancing costs are only incorporated for the day-ahead and hourly markets. The system balancing proposal therefore excludes all hedging costs.[47]

8. ICNU Misrepresents the Role of Bookout Transactions in the Company's Proposal.

ICNU argues that the Company's actual bookout data demonstrates that the Company does not systematically incur a cost on the volumes added to GRID under the system balancing proposal.[48] ICNU's focus exclusively on bookouts is too narrow—the pricing of the Company's volume adjustment is based on the historical average system balancing costs that were not already included in GRID.[49] These historical system balancing costs cover all day-ahead and hourly transactions, not just transactions that were booked out. Therefore, the gains or losses on bookouts are not, by themselves, representative of the Company's total system balancing costs.

Moreover, while ICNU argues that between 2008 and 2014 PacifiCorp recorded a gain on its bookout transactions, the more recent data demonstrates that bookouts have

[46] ICNU at 6-7; PAC/500, Dickman/15.
[47] PAC/500, Dickman/15.
[48] ICNU's Response Brief at 8-10.
[49] PAC/500, Dickman/15.

consistently incurred losses since 2012. The net gain on bookouts between 2008 and 2014 resulted from the aberrant market conditions between 2008 and 2010, which are not representative of the last four years.[50]

ICNU also contends that historical bookouts include monthly transactions and therefore the Company's volume adjustment includes hedging transactions.[51] The Company's filing includes the costs for only a subset of bookout transactions—the day-ahead and hourly transactions.[52] Because these transactions are priced based on the historical price of these short-term transactions, the system balancing proposal includes no hedging costs.

9. ICNU's Characterization of the System Balancing Proposal as a Bid-Ask Spread Remains Unpersuasive.

ICNU persists in its claim that the different purchase and sales prices modeled for the same hour is a bid-ask spread.[53] The Company's system balancing proposal measures the difference in system balancing purchase and sale prices caused by the timing of the transactions.[54] Because a bid-ask spread refers to the difference between concurrent offers to buy and sell the same product, an adjustment designed to compensate for the non-concurrent nature of the Company's short-term purchases and sales cannot be a bid-ask spread.[55] The Company's adjustment is conceptually similar to the forward price curve adjustment used by Idaho Power, which has never been referred to as a bid-ask spread.[56]

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[50] ICNU/303 at 2.
[51] ICNU's Response Brief at 10.
[52] This is why the Company refers to its volume adjustment as simply a "proxy for bookout transactions." PAC/500, Dickman/28.
[53] ICNU's Response Brief at 11.
[54] PAC/500, Dickman/15.
[55] PAC/600, Graves/10-11.
[56] *Re Idaho Power Co. Request for General Rate Revision*, Docket No. UE 167, Order No. 05-871 at 7-8 (July 28, 2005).

Based on ICNU's incorrect bid-ask theory, it argues for removal of current market caps and use of a $0.50 bid/ask spread in its place. The Commission reaffirmed the use of market caps in the 2013 TAM as necessary to avoid artificially shifting sales to illiquid, high-priced markets.[57] ICNU's bid-ask spread would allow far more sales into such markets than the Company's current market caps, in direct contravention of the Commission's order. ICNU has attempted to hide this fact by presenting its proposal without any evidence demonstrating how it would impact illiquid markets.

10. ICNU's Portland General Electric Company (PGE) Balancing Adjustment Undermines its Opposition to the System Balancing Proposal in this Case.

ICNU unsuccessfully attempts to distinguish its own system balancing adjustment in PGE's concurrent rate case. ICNU claims its PGE adjustment was not a system balancing adjustment even though it affected the modeling of transactions made to "balance the Company's overall load and resource position" after determining the dispatch of PGE's own resources.[58] ICNU's PGE adjustment was also calculated using hourly prices.[59]

ICNU further claims that its PGE adjustment was not intended to be an outside-the-model adjustment because ICNU wanted PGE to adjust its model.[60] Whether the adjustment is internal or external to the power cost model is immaterial because both adjustments are designed to account for market transactions that are not currently included either in or out of each utility's model.[61] ICNU also asserts that it was appropriate to rely on historical data for

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[57] *Re PacifiCorp 2013 Transition Adjustment Mechanism*, Docket No. UE 245, Order No. 12-409 at 7-8 (Oct. 29, 2012).
[58] ICNU's Response Brief at 14; PAC/905 at 2.
[59] PAC/905 at 7.
[60] ICNU's Response Brief at 14.
[61] PAC/905 at 2.

PGE because the data was intended to "produce a more normative result than the exclusion of such data would produce."[62] This logic supports PacifiCorp's system balancing proposal, which uses historical data to produce a more normative and accurate NPC result.

11. The Company's Wind Integration Costs Do Not Measure the Cost of Balancing the Company's System.

ICNU contends that PacifiCorp's Integrated Resource Plan (IRP) states that the system balancing costs the Company is proposing to recover here are already considered as part of the inter-hour wind and load integration charges.[63] To be clear, the IRP analysis that determines the inter-hour integration costs uses the same hourly price forecast now used in GRID, which is uniform across each month.[64] Therefore, the costs of the Company's more refined forward price curve reflected in the system balancing proposal are not captured in the inter-hour integration studies.

B. ICNU's Recommended Reserve Reduction is Unreasonable.

1. The Control Performance Standard 2 (CPS2) Metric is Irrelevant to Calculating the Company's Reserves.

While ICNU concedes that the CPS2 standard no longer applies to the Company,[65] ICNU still argues that the CPS2 standard should set the Company's reserve levels because the Company reports its CPS2 performance.[66] To accurately forecast NPC, however, the Company's reserve levels must be based on the reliability standard that actually governs its operations—the BAL-001-2 (BAAL) standard.[67] There is no evidence supporting ICNU's

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[62] ICNU's Response Brief at 14.
[63] ICNU's Response Brief at 15-16.
[64] PAC/500, Dickman/37-39.
[65] ICNU's Response Brief at 20.
[66] ICNU's Response Brief at 20.
[67] PAC/901 at 23.

claim that reducing reserves by 44 percent is a "very conservative" adjustment that will have no impact whatsoever on reliability.[68]

Despite clear language to the contrary,[69] ICNU claims the Company's wind integration studies are still based on the CPS2 standard because they include the L_{10} threshold and 10-minute intervals.[70] The L_{10} requirement is part of the BAAL standard and the Company's use of ten-minute intervals is a simplifying assumption, comparable to the use of hourly intervals to model NPC. In reality, BAAL requirements are triggered by one minute intervals, while the Company has 30 minutes to return its system to within the BAAL limits.

2. The Company's Lower CPS2 Scores Do Not Support Drastically Lower Reserves.

ICNU continues to argue that the Company's lower CPS2 scores demonstrate that it can carry far fewer reserves and still maintain system reliability.[71] ICNU's argument would have merit only if the Company had actually been carrying these lower reserves in the historical period when its CPS2 scores were declined. But there is no evidence that this is the case. On the contrary, the undisputed evidence is that the Company's actual reserves match the levels modeled in its wind integration studies and in this case.[72] The Company has had a lower CPS2 score not because it lowered capacity held in reserve on its system, but because it deployed that capacity consistent with the new BAAL standard. Thus, even if ICNU's premise was sound that the Company's reserves should be matched to its CPS2 score, there is

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[68] ICNU's Response Brief at 18.
[69] *See, e.g.,* PAC/901 at 44; PAC/902 at 19.
[70] ICNU's Response Brief at 21.
[71] ICNU's Response Brief at 19.
[72] PAC/902 at 24.

no evidence that the Company could reduce its reserves by 44 percent and maintain the CPS2 scores ICNU claims are reliable.

3. PacifiCorp's 2014 TRC Confirmed the Reasonableness of its Reserve Calculations.

The independent Technical Review Committee (TRC) from the Company's 2014 wind integration study specifically found that the Company was reasonable in using a 99.7 percent confidence level for reserve modeling—which is the same confidence level used by the Bonneville Power Administration (BPA) under the BAAL standard.[73] The TRC is comprised of independent industry experts.

ICNU claims that the 2014 TRC's acceptance of the Company's reserve modeling was "inexplicable and unsupported,"[74] and that the TRC "crucially failed to address or explain material deficiencies spotted by its predecessor and never rectified by the Company."[75] ICNU even claims conspiratorially that the TRC was "reconstituted" by the retirement of former ICNU expert Randy Falkenberg.

The record demonstrates the complete falsity of all of ICNU's accusations. The 2012 TRC requested that PacifiCorp provide a better explanation for how its 99.7 percent exceedance level tied to actual operations.[76] In response to this request, the Company used its 2014 wind integration study to explain in detail the basis for the 99.7 percent exceedance level.[77] Based on this explanation, the 2014 TRC recommended that the Company be "acknowledged for the diligent efforts made in implementing the recommendation by the

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[73] PAC/902 at 36-38.
[74] ICNU's Response Brief at 22.
[75] ICNU's Response Brief at 23.
[76] PAC/902 at 2.
[77] PAC/902 at 37.

TRC from the 2012 wind integration study," including an explanation of the reserve exceedance level, and the TRC found that Company's reserve calculations were reasonable.[78] Because five of the six members of the 2012 TRC, which ICNU champions, remained on the 2014 TRC, ICNU's negative insinuations about the 2014 TRC are not credible.

C. The Commission Should Reject Staff's and ICNU's Additional Energy Imbalance Market (EIM) Benefit Adjustments.

1. The Company Modeled Benefits from the Idaho Power Asset Exchange and the Additional Staff and ICNU Adjustments are Unsupported.

The TAM includes $0.6 million in benefits related to reduced wheeling expenses resulting from the Idaho Power Asset Exchange.[79] In addition, the GRID model in this case includes all of the transmission capability resulting from the Idaho Power Asset Exchange. The TAM also reflects EIM intra-regional dispatch benefits resulting from the Company's ability to use the increased dynamic transfer capability to more efficiently balance its system.[80] Discounting the benefits already reflected in this case, both Staff and ICNU attempt to impute additional EIM benefits from the increased dynamic transfer capability. Staff proposes to add inter-regional EIM dispatch benefits (on top of the intra-regional EIM benefits) and ICNU proposes to add additional flexibility reserve savings.

a. Staff's Assumption that Increased Dynamic Transfer Between Balancing Area Authorities (BAAs) Supports EIM Exports Lacks Any Evidentiary Support.

At hearing, Staff admitted that it failed to consider a greenhouse gas (GHG) adder that, if accounted for, undermines its underlying assumption that the Company's east-side

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[78] PAC/902 at 36-37.

[79] TR. 64-65 (Ordonez).

[80] PAC/100, Dickman/10-11; Staff/100, Ordonez/14 ("The intra-regional dispatch benefits are the benefits of PacifiCorp optimizing its economic dispatch within the Company's BAAs."); Staff/201, Ordonez/4.

coal plants support nearly all of the California Independent System Operator (CAISO) exports.[81] In its Response Brief, Staff argues that its use of only 50 percent of the additional dynamic transfer capability in its adjustment "more than accounts for whatever impact the GHG adder may have to the calculation of the average variable cost of the coal plants."[82] But inclusion of the GHG adder demonstrates that the Company's east-side coal plants were not the marginal resources used for exports to the CAISO—meaning that the dynamic transfer between BAAs was not always used for exports to the CAISO. The fundamental assumption underlying Staff's adjustment is wrong. Staff cannot "account" for this error simply by proposing a smaller adjustment when there is no evidence to support the adjustment in the first place.

Staff also claims that the Company's discovery responses were inconsistent because one response stated that the Company used its increased dynamic transfer for the EIM while another response stated that the increased dynamic transfer would not correspond to increased inter-regional EIM dispatch benefits.[83] The confusion stems from the fact that the Company also uses the increased dynamic transfer capability for the EIM on an intra-regional basis, not only on an inter-regional basis to support additional exports to the CAISO. The Company's data request response correctly stated that the limitation on inter-regional exports is the transmission capacity on the California-Oregon Intertie (COI), not the dynamic transfer capability between BAAs.[84] The only reason that Staff perceived an inconsistency is

[81] TR. 71-73 (Ordonez); PAC/909 at 45; Staff/200, Ordonez/9.
[82] Staff's Response Brief at 8.
[83] Staff's Response Brief at 6-7.
[84] Staff's Response Brief at 6-7.

because Staff assumed, without support or verification, that the increased dynamic transfer capability supported only exports to the CAISO and not intra-regional EIM benefits.[85]

b. The Company Cannot Dynamically Transfer Flexibility Reserves Between BAAs.

ICNU argues that the Company's increased dynamic transfer capability will allow it to transfer flexibility reserves between its BAAs.[86] ICNU's only support for this adjustment is the Company's prior testimony that the increased dynamic transfer capability will allow for future EIM transfers.[87] As just discussed, the Company's GRID model is currently using the increased dynamic transfer capability for intra-regional EIM transfers. Notably absent from the Company's testimony is any statement that the future EIM transfers would include flexibility reserves. In fact, the Company's testimony, the Energy and Environmental Economics, Inc. (E3) studies, and the Company's wind integration studies all demonstrate that the Company cannot transfer flexibility reserves as ICNU assumes.[88] Staff acknowledged this reality in dropping its own adjustment for EIM reserve savings from the Idaho Power Asset Exchange.

ICNU also claims that its flexibility reserve adjustment does not overlap with its regulating reserve adjustment because flexibility reserves and regulating reserves are two separate and distinct reserve categories.[89] But ICNU also testified that the EIM's sub-hourly transfers will allow only regulating reserves savings, not flexibility reserve savings.[90]

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[85] PAC/100, Dickman/10-11.
[86] ICNU's Response Brief at 24.
[87] ICNU's Response Brief at 24.
[88] PAC/500, Dickman/54-55; PAC/902 at 30; PAC/909 at 18.
[89] ICNU's Response Brief at 25.
[90] PAC/900 at 1 (only basis for transfer of flexibility services is "ability to effectuate sub-hourly transfers between balancing areas. . ."); ICNU/100, Mullins/29 ("The flexibility reserves savings represent the load following reserve savings associated with 'aggregating the two systems' load, wind, and solar variability and

Therefore, ICNU's own testimony undermines its adjustment because ICNU testified that there can be no flexibility reserve savings due to sub-hourly transfers under the EIM.

2. ICNU Concedes that its Seasonality Adjustment Relies on Anomalous Data.

ICNU claims that its seasonality adjustment is based on "nothing but actual data."[91] But it is not based exclusively on *actual EIM data*. ICNU's proposal still relies on only two months of EIM data and then uses an untested extrapolation methodology that ICNU's own witness disregarded in testimony filed in Wyoming.[92] ICNU has never rebutted the fact that its extrapolation methodology does not correlate to actual EIM experience and is inconsistent with its recommendation for additional EIM benefits due to new participants.[93]

ICNU faults the Company for using only actual EIM results to forecast test period benefits, claiming that the initial EIM results included anomalies that are not expected to occur in 2016.[94] But ICNU's entire adjustment is based on the first two months of EIM data that they now claim contain anomalies that pose a "significant concern."[95] The Company's use of ten months of data smooths any anomalies that may have occurred in the early operation of the EIM.

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forecast errors.' These reserves savings, which are representative of having a more diverse set of resources upon which to hold reserves, are distinct from the regulation reserve savings that will accrue to the Company as a result of moving to a sub-hourly market and scheduling paradigm."); PAC/903 at 10.

[91] ICNU's Response Brief at 25.

[92] ICNU/104, Mullins/1; ICNU/200, Mullins/4.

[93] PAC/500, Dickman/59-61; ICNU/100, Mullins/36-39.

[94] ICNU's Response Brief at 26.

[95] *Id.*; ICNU/104, Mullins/1.

3. ICNU Still Cannot Defend its Inflated Calculations of New Participant Benefits.

ICNU devised its own methodology for determining the inter-regional EIM dispatch benefits that will accrue to PacifiCorp as a result of Puget Sound Energy (PSE) and Arizona Public Service (APS) joining the EIM. ICNU's methodology produces results for PacifiCorp that are substantially greater than the benefits estimated in each utility's E3 study for all EIM participants.[96] When confronted with these facts at hearing, ICNU's witness admitted that this was a "fair criticism"[97] and that he "agree[d] with the overall criticism that using [his] simplistic method, it calculates a level above or nearly at the top of the range of numbers" that E3 calculated for *all participants*.[98] While ICNU's witness challenged the application of his own allocation factor to E3's estimated total benefits, he acknowledged that his estimated PacifiCorp benefits were more than double E3's primary scenarios for all participants.[99]

ICNU now suggests that its methodology should be compared to the average of the range of benefits forecast by E3, rather than E3's primary scenario, and without applying ICNU's allocation factor.[100] Using this metric, the APS E3 study has average benefits of $1.62 million per year for *all* participants, which compares to ICNU's calculation of $2.9 million for PacifiCorp alone.[101] The PSE E3 study has average benefits of $0.9 million per year for *all* participants, which compares to ICNU's calculation of $1.4 million for

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[96] TR. 51, 53, 55 (Mullins); PAC/906 at 45; PAC/907 at 49.
[97] TR. 50-51 (Mullins) ("But I think the criticism that our simplistic method attributed a large amount of the subhourly dispatch savings relative to these numbers [in the E3 studies] is probably a fair criticism.").
[98] TR. 53-54 (Mullins).
[99] TR. 53-55 (Mullins).
[100] ICNU's Response Brief at 27.
[101] TR. 51 (Mullins); PAC/906 at 45.

PacifiCorp alone.[102] No matter the comparison, ICNU's methodology produces wildly inflated benefits, despite ICNU referring to it as a "conservative" adjustment.[103]

D. ICNU's Criticisms of the Company's Decisions Related to the Hermiston Power Purchase Agreement (PPA) and Transmission Contract are Meritless.

ICNU claims that the Company's IRP modeling does not properly account for the west-side winter peak and the Company was imprudent for failing to analyze the winter peaking benefits of the Hermiston PPA before terminating the contract.[104] In response to this claim, the Company's reply testimony explained how its IRP modeling correctly accounted for the west-side winter peak and had never been criticized on this basis.[105]

ICNU now argues that the Commission should ignore the Company's reply testimony because it is a "post hoc rationalization" and that the only relevant evidence is "documentation prepared in advance of this proceeding."[106] But the Company's testimony described the IRP analysis that pre-dated the decision to terminate the Hermiston PPA and specifically refuted ICNU's claims.[107] ICNU can choose to ignore the record in this case, but the Commission should not.

Further, ICNU claims that the Company's own analysis demonstrates that the BPA transmission rights are unnecessary.[108] But the modeling in this case is undisputed that, even without the Hermiston PPA, the full transmission capacity is still utilized during the test period.[109]

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[102] TR. 55 (Mullins); PAC/907 at 49.
[103] ICNU/100, Mullins/39.
[104] ICNU's Response Brief at 28; ICNU/100, Mullins/40.
[105] PAC/500, Dickman/74-76.
[106] ICNU's Response Brief at 28.
[107] PAC/500, Dickman/74-76 (describing what the Company knew when it made its decision).
[108] ICNU's Response Brief at 30.
[109] PAC/500, Dickman/77.

E. The Company's De-Rate Modeling is Superior to the Docket UM 1355 Modeling.

ICNU criticizes the Company's de-rate modeling without ever acknowledging or responding to the fact that its witness explicitly supports the Company's proposal in a Wyoming rate case.[110] Indeed, in Wyoming Mr. Mullins testified that "[t]here is no basis for the Company to use one methodology in Oregon and a different, less reasonable and less favorable to ratepayers, in Wyoming."[111]

ICNU also claims that modeling a pattern of more frequent, shorter outages results in greater costs.[112] While this may be true in actual operations, it is not true in GRID where the model perfectly forecasts around outages.[113] ICNU also contends that more frequent, short outages are not representative of outage patterns in actual operations.[114] But ICNU's proposal to continue to use the docket UM 1355 methodology produces entirely unrealistic results because it assumes every single plant is partially unavailable every single hour.[115] PacifiCorp's evidence demonstrates clearly that its modeling is more accurate than the existing docket UM 1355 methodology.[116]

Staff and ICNU also both recommend that any changes in de-rate modeling must occur in a generic proceeding.[117] Neither party squares this recommendation with the fact that the de-rate modeling at issue here applies to only PacifiCorp, making a generic proceeding overbroad and unnecessary.[118]

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110 PAC/904 at 2.
111 PAC/904 at 7.
112 ICNU's Response Brief at 31.
113 PAC/500, Dickman/78-79.
114 ICNU's Response Brief at 31.
115 PAC/500, Dickman/78.
116 PAC/100, Dickman/35.
117 Staff's Response Brief at 11; ICNU/100, Mullins/44-45.
118 Order No. 10-414 at 6-7.

F. The Company's Wind Modeling is Consistent with Precedent and Uses the Most Reliable Data.

ICNU claims that modeling wind generation with the same planning assumptions originally used to justify the wind facilities is consistent with Order No. 08-548.[119] To support this statement, ICNU claims that the Company's new modeling responds to court orders mandating curtailment and therefore the reduced capacity factor results from the Company's "own failings."[120] First, ICNU's argument that the Company's compliance with federal environmental regulations is somehow a "failure" on the Company's part is iniquitous. The fact that the curtailment is the result of compliance with federal law makes its modeling more compelling, not less.[121]

Second, nothing in Order No. 08-548 suggests that compliance with federal law is a basis to reject the use of the "most reliable data" in favor of planning assumptions. On the contrary, the Commission was clear that the planning assumptions are "not dispositive for purposes of forecasting resource availability for ratemaking purposes."[122]

ICNU cannot point to any precedent for its recommendation to use planning assumptions when compliance with federal law requires curtailment. Indeed, ICNU cannot even reconcile its recommendation here with its opposite position in prior cases where it has explicitly rejected the use of planning assumptions in favor of the most up-to-date data.[123]

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[119] ICNU's Response Brief at 31.

[120] ICNU's Response Brief at 32.

[121] PAC/500, Dickman/81.

[122] *Re PacifiCorp 2009 Renewable Adjustment Clause Schedule 202*, Docket No. UE 200, Order No. 08-548 at 21 (Nov. 14, 2008) ("Although the estimated capacity factor at the time of project approval is dispositive for purposes of prudency review, it is not dispositive for purposes of forecasting resource availability for ratemaking purposes. The most recent reliable data should be used to set rates for the test period, recognizing that such data necessarily will be uncertain, particularly at start-up.").

[123] PAC/500, Dickman/80-81.

ICNU further claims that its prior stipulation with PGE agreeing to use a five-year rolling average of actual wind generation to forecast test period generation is non-precedential because ICNU never specifically agreed that five-years was reasonable in the stipulation.[124] ICNU fails to mention that PGE has continued to use a five-year rolling average in subsequent cases, without objection from ICNU.[125]

G. The Commission Should Reject Noble Solutions' Direct Access Proposals.

1. Noble Solutions' Renewable Energy Credit (REC) Arguments are Unpersuasive and Based on Speculation.

Noble Americas Energy Solutions LLC (Noble Solutions) asserts that direct access customers pay twice for RPS compliance, so the transition adjustment should include a credit for direct access customers.[126] Noble Solutions failed to establish the existence of incremental RPS compliance costs, however, or any means by which these costs could be fairly carved out and credited to direct access customers.[127]

Noble Solutions turns to a California Public Utility Commission (CPUC) decision to buttress its claim.[128] There are a multitude of distinctions between a CPUC decision designed to address state and CPUC-specific laws and administrative rules and the case at hand. For example, PacifiCorp's RPS compliant renewable resources were cost effective at the time they were acquired and thus did not represent incremental costs above alternative

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[124] ICNU's Response Brief at 32-33.

[125] *See, e.g.*, *Re Portland Gen. Elec. Co.*, Docket No. UE 283, PGE/500, Niman – Peschka – Hager/28, PGE/300, Tooman – Macfarlane/18 (Feb. 13, 2014).

[126] Noble Solutions' Response Brief at 3-5.

[127] TR. 83:18-84:5 (Dickman).

[128] *Rulemaking regarding whether, or subject to what Conditions, the suspension of Direct Access may be lifted consistent with Assembly Bill 1X and Decision 01-09-060*, CPUC Decision 11-12-018, 2011 Westlaw 627827 (Dec. 1, 2011).

non-RPS resources available at the time.[129] Because PacifiCorp has sufficient RPS compliant resources for the near-term, it will not be adding new compliance costs for several years. This is a notable distinction from the CPUC's decision, which claimed that, "Renewable resources are more costly than traditional gas-fired generation, and thus have a higher market price as compared to the embedded cost of the utilities' portfolios."[130]

Noble Solutions plucks out a quote from the CPUC Order to support its assertion that, "[e]ven if the [utilities] cannot sell the renewable attributes, they still benefit from them."[131] The quote is taken out of context and highlights the inapplicability of this California decision. In the California case, there was a dispute over what to do with pre-2004 renewable resources. The CPUC decided that because a utility's "requirement to procure additional RPS-complaint renewable resources is reduced one for one, for every MWh of pre 2004 renewable resources generated in the IOUs portfolio" that the utilities and bundled customers, even if they could not sell the renewable resources, still benefited from the pre-2004 renewable resources.[132] The CPUC did not issue an absolute statement that renewable resources always benefit utilities even if they are not sold, but instead the CPUC made a limited decision for a particular question in California regarding the benefits of pre and post-2004 renewable resources. The citation is not only irrelevant, it is misleading.

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[129] *See In the Matter of PacifiCorp, dba Pacific Power, 2012 Renewable Portfolio Standard Compliance Report*, Docket No. UM 1660, Order No. 13-420, Appendix A at 1 (Nov. 12, 2013) ("The Report indicates that PacifiCorp complied with Oregon's RPS…[i]n its report PacifiCorp states that its cost of compliance for 2012 was negative 0.82 percent of revenue requirement… . PacifiCorp also reported a negative compliance cost in its 2011 compliance report."). *See also In the Matter of PacifiCorp, dba Pacific Power, 2013 Renewable Portfolio Standard Compliance Report,* Docket No. UM 1700, Order No. 14-371, Appendix A at 1 (Oct. 28, 2014) ("In its report PacifiCorp states that its cost of compliance was 0.02 percent of annual revenue requirement…").
[130] CPUC Decision 11-12-018 at 10.
[131] Noble Solutions' Response Brief at 9.
[132] CPUC Decision 11-12-018 at 24.

Finally, Noble Solutions wrongly claims that there is no need to track credits paid to returning direct access customers because RPS compliance is an annual cost. Any RPS compliance value paid to direct access customers for RECs, which are then banked for the use of Oregon customers, needs to be recovered from returning customers before that REC is used on behalf direct access customers.[133] Otherwise, direct access customers will receive a double benefit.

2. Noble Solutions' Consumer Opt-Out Charge Proposal Was Fully Considered and Twice Rejected by the Commission Earlier this Year.

a. Contrary to Noble Solutions' Misrepresentations, the Consumer Opt-Out Charge does not Include Generation Assets Added in Years Six through 10.

Noble Solutions asks the Commission to reconsider the consumer opt-out charge approved and affirmed just four months ago and substantially decrease the charge during years six through 10. Noble Solutions justifies its recommendation on the basis that direct access customers should not pay for additional generation investments occurring during years six through 10.[134] For example, Noble Solutions claims that the consumer opt-out charge is contrary to Oregon's direct access statutes because the law "does not allow recovery for utility acquisitions made six years or more after the customer opted out."[135] Noble Solutions also points to a CPUC decision precluding a stranded cost calculation from considering resources acquired after the customer departs.[136]

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[133] Noble Solutions' Response Brief at 11.

[134] *See, e.g.*, Noble Solutions' Response Brief at 12 ("the Commission did not suggest that the direct access customers electing to enter the five-year program should be responsible for any *additional* fixed-generation costs PacifiCorp adds to its rate base in years six through 10 *after* the customer stops using PacifiCorp's generation resources.").

[135] Noble Solutions' Response Brief at 13-14.

[136] Noble Solutions' Response Brief at 14.

Noble Solutions' premise—that the consumer opt-out charge currently requires direct access customers to pay for resources acquired after their departure—is untrue. Indeed, despite Noble Solutions' attempt to obfuscate, Noble Solutions concedes this fact in its response brief when it states that the Commission-approved charge "escalate[s] the costs of the set of resources existing at the time of departure from the system."[137] To be clear, in years six through 10, the fixed generation costs at the end of year five are held constant in real terms and inflation is applied only to allow the Company to reduce the charge to a present value.[138]

b. Noble Solutions Cannot Distinguish its Recommendation for Calculation of the Opt-Out Charge in Years Six through 10 with its Support for An Inflation Adjustment in Years One through Five.

Noble Solutions agrees that escalation during the first five years is appropriate because fixed costs are updated as new resources are added.[139] For years six through 10, however, Noble Solutions argues there should be no escalation because direct access customers should not pay for additional resources. This argument again relies on the misrepresentation that the inflation adjustment in years six through 10 actually accounts for incremental generation investments.[140] In fact, the exact same inflation adjustment is made to the fixed costs in years one through five as in years six through 10 because costs from both periods must be reduced to a present value to calculate the charge.[141] The only difference between the two periods is that years six through 10 do not include costs of new investments. If it is appropriate to include an inflation adjustment in years one through five, as Noble

[137] Noble Solutions' Response Brief at 15.
[138] PAC/500, Dickman/84-85.
[139] Noble Solutions' Response Brief at 16-17
[140] Noble Solutions' Response Brief at 17.
[141] TR. 105 (Dickman).

Solutions concedes, then it is equally appropriate to have the same adjustment in years six through 10.

c. Noble Solutions Presented No New Evidence Here that It Could Not Have Produced in Docket UE 267.

Noble Solutions complains that it had "no opportunity in UE 267 to present detailed testimony regarding appropriate refinements to make to a 10-year charge."[142] This claim is not true. Noble Solutions had multiple opportunities to submit testimony and cross-examine witnesses in docket UE 267 and choose not to do so.

Noble Solutions' claims that it was preoccupied with larger issues and could not "pick around the edges" of the consumer opt-out charge is equally disingenuous.[143] Noble Solutions raised this exact same issue in post-hearing briefs and on reconsideration in docket UE 267.[144] The escalation of fixed costs during years six through 10 was squarely an issue in docket UE 267 because it was addressed by PacifiCorp in both its original filing and its opening testimony.[145] In its opening testimony, Staff specifically endorsed the escalation of fixed costs just as PacifiCorp proposed.[146] PGE's five-year program, which preceded

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142 Noble Solutions' Response Brief at 19.
143 Noble Solutions' Response Brief at 19.
144 PAC/500, Dickman/85-86.
145 *Re PacifiCorp's Transition Adjustment, Transition Adjustment, Five-Year Cost of Service Opt-Out*, Docket No. UE 267, PacifiCorp Advice No. 13-004 (Feb. 28, 2013); Docket No. UE 267, PAC/200, Duvall/5-6 (June 14, 2013).
146 Staff/100, Compton/6 ("**Q. Do you support PacifiCorp's projected escalation of its fixed generation costs in the construction of the Schedule 200 base supply portion of the direct access?** A. Yes. The desired escalation can be achieved by using two approaches. The first is to forecast escalation in fixed generation costs as PacifiCorp has done (aside from the staff recommendation of limiting those charges to a five-year period forecast). The second is to update the applicable fixed generation rates as PacifiCorp has those rates changed through general rate cases. The latter approach was supported in the Docket UE 262 settlement. Staff is fine with either approach."). *In the Matter of Portland General Electric Company, Request for General Rate Revision*, Docket No. UE 262 (Feb. 15, 2013). The Company requests that the Commission take official notice of this testimony under OAR 860-001-0460(1)(d).

PacifiCorp's, also includes the same methodology as here, which Staff described as resulting in "inclining fixed-cost transition fees."[147]

d. Contrary to Noble Solutions' Claims, PacifiCorp Presented Evidence Contradicting its Adjustment and Noble Solutions is Not Correcting An Error.

Noble Solutions claims that the "record is devoid of evidence" contradicting its adjustment.[148] In fact, PacifiCorp testified that that Noble Solutions' claim that generation costs decline over time is overly simplistic and ignores offsetting factors and the Company's inflation adjustment reasonably keeps generation costs constant in real terms.[149]

Noble Solutions also argues that its proposed changes to the consumer opt-out charge "corrects an error."[150] Noble Solutions did not use the word "error" in its prefiled testimony or pre-hearing brief.[151] Instead, for the first time in cross-examination, Noble Solutions attempted to equate its significant change to the consumer opt-out charge to correcting a mathematical error.[152] But the testimony of PacifiCorp's witness Mr. Brian Dickman at hearing completely undercuts this new argument.

Noble Solutions' counsel asked Mr. Dickman whether the Company would change the consumer opt-out charge calculation if it found an error that benefited direct access customers to PacifiCorp's detriment. Mr. Dickman responded that, "If PacifiCorp finds an

[147] *See* Docket No. UE 262, Staff/300, Compton/10-11. The Company requests that the Commission take official notice of this testimony under OAR 860-001-0460(1)(d).
[148] Noble Solutions' Response Brief at 15.
[149] PAC/500, Dickman/84-85; TR. 105 (Dickman).
[150] Noble Solutions' Response Brief at 13.
[151] *See* Noble Solutions' Pre-Hearing Brief (Aug. 17, 2015) and Noble Solutions/100, Higgins/1.
[152] TR. 105-106 (Dickman).

error, in general, it will propose to change it, yes. But I don't believe that we've made an error in our calculation of the consumer opt-out charge."[153]

Mr. Dickman testified that the Company escalated the consumer opt-out charge in years six through 10 at the average rate of inflation to hold its fixed generation costs constant in real terms, even though some components of the consumer opt-out charge would increase at a rate greater than inflation.[154] This testimony is consistent with the Company's position in docket UE 267, which the Commission approved in its original order and on reconsideration.[155] After this history, Noble Solutions' current claim that it is simply seeking to correct an error or oversight is not credible.

3. There is No Reason to Change the Company's Treatment of Late Direct Access Service Requests Before Commencement of the Five-Year Program.

Noble Solutions also requests reconsideration of the Commission's decision in docket UE 267 regarding the treatment of late Direct Access Service Requests (DASRs).[156] Noble Solutions mostly presents scenarios that could result in DASRs being submitted by an Electricity Service Supplier (ESS) after the deadline set forth in the Commission's rules and the Company's tariff.[157] While there are undoubtedly numerous scenarios in which a deadline can pass without the proper action, this does not explain why an established deadline is inappropriate or burdensome. The Company has yet to hold a single enrollment

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[153] TR. 106 (Dickman; emphasis added).
[154] TR. 105.
[155] *Re PacifiCorp's Transition Adjustment, Five-Year Cost of Service Opt-Out*, Docket No. UE 267, Order No. 15-060 at 6-7 (Feb. 24, 2015); *affirmed on reconsideration*, Order No. 15-195 (June 16, 2015).
[156] *Re PacifiCorp's Transition Adjustment, Five-Year Cost of Service Opt-Out*, Docket No. UE 267, Order No. 15-195 at 2-3 (June 16, 2015) (changes to the five-year program will be adopted if there is "new evidence or arguments demonstrating that the consumer opt-out charge is unjust or unreasonable.").
[157] Noble Solutions Response Brief at 20-29.

window for the five-year program and there is no evidence that the current treatment of late DASRs is an unreasonable impediment to program participation.

III. CONCLUSION

The Commission should approve the Company's NPC forecast in this case. The Company's proposals result in a more accurate NPC forecast, especially by including system balancing costs that were previously omitted and by accurately and fully reflecting the benefits resulting from the Company's participation in the EIM. In this way, the Company's modeling is consistent with the underlying purpose of the TAM.

Respectfully submitted this 5th day of October, 2015.

Katherine A. McDowell
McDowell Rackner & Gibson PC

Matthew McVee
Assistant General Counsel
PacifiCorp d/b/a/ Pacific Power

Attorneys for PacifiCorp