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VIA ELECTRONIC FILING

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Public Utility Commission of Oregon
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 Prehearing Memorandum.

Please contact this office with any questions.

Very truly yours,

Katherine McDowell

cc: Service List

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 296

In the Matter of:
PACIFICORP, dba PACIFIC POWER
2016 Transition Adjustment Mechanism

PACIFICORP'S PREHEARING MEMORANDUM

August 17, 2015

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2016 Transition Adjustment Mechanism	

PacifiCorp d/b/a Pacific Power (PacifiCorp or the Company) submits this Prehearing Memorandum to the Public Utility Commission of Oregon (Commission) in compliance with Administrative Law Judge Sarah Rowe's ruling on May 1, 2015.

I. INTRODUCTION

PacifiCorp's Transition Adjustment Mechanism (TAM) is an annual filing to update the Company's forecast net power costs (NPC).[1] In this TAM filing, PacifiCorp's forecast NPC for 2016 are $375.2 million on an Oregon-allocated basis.[2] PacifiCorp requests an order increasing its rates by approximately $12.4 million, or 1.0 percent overall, to reflect the updated forecast.[3] To put this in context, the average shortfall between NPC in rates and actual NPC in 2013-2014 was $34.5 million;[4] the proposed increase is approximately one-third of this amount.

The Company made several modeling refinements to its NPC forecast to more accurately match the actual NPC during the test period and partially address the Company's systematic under forecasts of NPC in the TAM. The most notable change is the Company's

[1] *See In the Matter of PacifiCorp, dba Pacific Power 2009 Transition Adjustment Mechanism*, Docket No. UE 199, Order No. 09-274 at 2 (July 16, 2009).
[2] PAC/500, Dickman/1.
[3] PAC/500, Dickman/5. This forecast is subject to a final update in November 2015.
[4] PAC/500, Dickman/15.

proposal to more accurately reflect system balancing purchases and sales.[5] PacifiCorp also made improvements to the modeling of regulation reserves, forced outages, and wind generation.

The Company's 2016 TAM also reflects two major NPC reductions. First, as updated in PacifiCorp's reply testimony, the filing now includes $12.4 million in Energy Imbalance Market (EIM) cost savings on a total system basis, or approximately $3 million on an Oregon-allocated basis. Second, the filing reflects a total company cost reduction of $12.5 million from the Company's non-renewal of the Hermiston power purchase agreement (PPA), effective June 30, 2016, or approximately $3 million on an Oregon-allocated basis.[6]

Staff of the Public Utility Commission of Oregon (Staff), the Citizens' Utility Board of Oregon (CUB), the Industrial Customers of Northwest Utilities (ICNU), and Noble Americas Energy Solutions LLC (Noble Solutions) oppose or offer adjustments to the above proposals, as outlined below (all NPC amounts stated in this prehearing memorandum are Oregon-allocated, unless otherwise stated).

- Staff, CUB, and ICNU oppose the Company's system balancing proposal, which would reduce the Company's NPC by approximately $8 million. The Company provided significant evidence on the reasonableness and need for this modeling change.[7] This includes expert testimony from Frank Graves of the Brattle Group, opining that the Company's losses from short-term system balancing are systematic and warrant the modeling change proposed by the Company. Notably, the Company has utilized several years of detailed

[5] PAC/100, Dickman/22-30.
[6] PAC/500, Dickman/75.
[7] PAC/500, Dickman/14-42.

historical data to support its system balancing proposal. Staff and ICNU have proposed to increase EIM benefits in this case relying on limited historical data and speculation, but unreasonably apply a different standard when it comes to allowing the Company to recover its actual, fully substantiated costs.[8]

- ICNU proposes to replace GRID's market caps with a $0.50 per megawatt-hour (MWh) bid-ask spread. This adjustment, which seeks to reopen an issue that was fully litigated and resolved by the Commission in the 2013 TAM, would artificially increase sales volumes to illiquid market hubs and reduce the Company's NPC by $1.7 million.[9]
- In its cross-answering testimony, Staff withdrew its intra-hour EIM and reserve sharing adjustments proposed in its Opening Testimony. At the same time, Staff proposed an entirely new and procedurally improper EIM adjustment, related to dispatch benefits, which would reduce the Company's NPC by $1.1 million.[10] Staff's adjustment was filed concurrently with the Company's Reply Update, in which the Company increased EIM benefits by $800,000.[11]
- ICNU proposed $1.5 million in EIM-related adjustments, addressing issues to which the Company fully responded in its Reply Update.[12] Specifically, the

[8] PAC/600, Graves/1-11.
[9] PAC/500, Dickman/40-42.
[10] PacifiCorp reserves the right to offer live supplemental reply testimony in response to Staff's improper cross-answering testimony at hearing. PacifiCorp makes the same reservation of rights with respect to ICNU's improper cross-answering testimony, discussed below.
[11] PAC/500, Dickman/12.
[12] PAC/500, Dickman/56-73.

Company added additional inter-regional dispatch benefits and cost savings resulting from reduced reserve requirements.

- CUB raised an EIM-related issue on seasonality, suggesting that the Company defer actual EIM benefits due to a dearth of historical EIM data. The Company responded to CUB's adjustment by adding additional data in its Reply Update, adjusted for seasonality.[13]
- ICNU has proposed a regulation reserve adjustment of $2.8 million, arguing that the Company should plan for compliance with North America Electric Reliability Corporation (NERC) reliability requirements only 90 percent of the time—replacing the Company's current 100 percent compliance target, which is reflected using a 99.7 percent confidence interval in the Company's wind integration studies. This adjustment would slash the Company's regulation reserves by one-third. No other party supports this adjustment, and it is fundamentally inconsistent with ICNU's EIM adjustments, which impute benefits associated with higher reserve levels.[14]
- ICNU challenged the prudence of the Company's decision not to renew the Hermiston PPA (and the associated transmission), while also counting the $3.0 million in non-renewal benefits in its recommended NPC. No other party supports this one-sided adjustment.[15]

[13] PAC500, Dickman/72-73.
[14] PAC/500, Dickman/46-53.
[15] PAC/500, Dickman/73-77.

- ICNU challenged the Company's modeling refinements to forced outage rates[16] and wind generation,[17] even though ICNU's witness has not contested their accuracy and has proposed or accepted the same modeling approach in other cases.
- For the third time this year, Noble Solutions challenges the escalation of the Schedule 200 opt-out charge in the Company's five-year opt-out program. There is nothing new to address on this issue. Noble Solutions also seeks a credit for freed-up renewable energy certificates (RECs), even though the Commission requires the Company to bank all RECs that are compliant with the renewable portfolio standard (RPS).[18] Finally, Noble Solutions seeks a change in the five-year opt-out program to allow parties leeway to miss enrollment deadlines. While the Company opposes this proposal as presented, it has offered additional conditions to make it more workable.[19]

As detailed below, the parties' adjustment are not supported by evidence demonstrating that PacifiCorp's NPC is unreasonable or impudent, nor are they supported by compelling policy arguments. Most importantly, if adopted, the parties' adjustments would decrease the accuracy of the NPC forecast, undercutting the goal of this TAM proceeding.

[16] PAC/500, Dickman/77-79.
[17] PAC/500, Dickman/79-82.
[18] *In the Matter of PacifiCorp, dba Pacific Power, Application for Sale of Renewable Energy Credits*, Docket No. UP 266, Order No. 11-512 (Dec. 20, 2011).
[19] PAC/500. Dickman/83-86.

II. ARGUMENT

A. The Commission Should Approve the Company's Proposed NPC Modeling Changes to Improve NPC Accuracy.

PacifiCorp's 2016 TAM filing made several changes to the GRID inputs and improved the accuracy of forecast NPC.[20] These proposals capture costs and benefits that went unrecognized in past NPC forecasts and they are consistent with the Commission's encouragement to improve the accuracy of NPC modeling.[21]

ICNU's cross-answering testimony improperly includes a new argument that, because GRID accurately forecasts NPC, the Company's system balancing adjustment is unnecessary.[22] While the Company agrees with ICNU that GRID is an accurate model, as Mr. Graves testifies, there are practical limitations in any power system forecasting model.[23] Ultimately, the Company's NPC variances are driven by the accuracy of the forecast inputs into the GRID model, not the model itself—a point that ICNU concedes.[24] The Company's system balancing proposal is specifically intended to improve its NPC forecast by adjusting the inputs to the GRID model to better reflect the Company's actual experience and adjusting the outputs from the GRID model to better reflect the actual power market environment in which the Company operates.[25]

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[20] PAC/100, Dickman/21-41.

[21] PAC/100, Dickman/21-22; PAC/500, Dickman/17-20. *See also In the Matter of PacifiCorp d/b/a Pacific Power 2013 Transition Adjustment Mechanism*, Docket No. UE 245, Order No. 12-409 at 7 (Oct. 29, 2012). In the 2013 TAM, the Commission directed PacifiCorp, "to refine its modeling to produce the best possible estimates of all components of net power costs."

[22] ICNU/200, Mullins/8.

[23] PAC/200, Graves/4-7.

[24] ICNU/200, Mullins/8.

[25] ICNU also contends that one of the only ways to determine the accuracy of GRID is through the use of back-casting. ICNU/200, Mullins/10-11. Because PacifiCorp is not contending that GRID model itself is inaccurate, ICNU's argument that the Company should have produced a back cast is irrelevant. To the extent that ICNU is claiming that historical information should inform the analysis of the Company's proposal, however, this supports the proposal because it is based entirely on actual historical data.

ICNU's improper cross-answering testimony also downplays the need for the Company's modeling refinements, claiming that the Company's NPC under-recovery is a function of various temporary factors, including weather extremes in 2013 and 2014.[26] ICNU is correct that NPC can be affected by factors that are difficult to forecast, which makes it all the more important to refine the Company's NPC modeling to capture systematic, measurable costs and benefits as accurately as possible. Additionally, ICNU ignores the fact that the Company has experienced 5 to 10 percent under recovery of its NPC in Oregon for many years.[27] These variances have not "washed out" over time;[28] in the past four years, the monthly forecast has underestimated NPC 42 straight times. This obviously goes beyond normal variations in weather and markets to systematic deficiencies in the forecast, deficiencies which the Company is attempting to address through its modeling proposals in this case.

B. Day-Ahead and Real-Time Balancing Transactions

1. The Company's system balancing proposal improves the accuracy of the GRID model.

As currently modeled, the Company's NPC systematically understates the Company's system balancing costs.[29] The GRID model balances loads and resources depending on whether the Company needs resources or has excess resources.[30] The balancing transactions are independently calculated for each hour and for the precise volume required by the model.[31] The purchase and sales prices are currently based on an hourly forward price curve

[26] ICNU/200, Mullins/9.
[27] PAC/200, Graves/2-3.
[28] PAC/200, Graves/3.
[29] PAC/500, Dickman/17. The Company's under recovery of Oregon-Allocated NPC increased from $33 million (or 8.81 percent) in 2013 to $36 million (or 9.56 percent) in 2014.
[30] PAC/100, Dickman/23.
[31] PAC/100, Dickman/23.

that is developed from monthly heavy-load hours (HLH) and light-load hours (LLH) prices with hourly scalars applied. Importantly, the scalars do not change based on the volume of the system balancing transactions and they are identical within a given month for all weekdays of that month.[32] Consequently, without adjustment, the weighted average price of system balancing transactions in the NPC forecast each month does not reflect the historical difference experienced with the Company's actual system balancing transactions.

PacifiCorp balances its position with monthly, daily, and hourly products, in a manner that varies significantly from what is now modeled in GRID.[33] The model does not capture price variability within a month and does not account for the fact that products available to balance the Company's position are primarily traded in 25 MW blocks.[34]

The Company must maintain a balanced system, even at the cost of becoming a price-taker subject to whatever price is available at the time.[35] The Company has historically bought more during higher-than-average price periods in each month and sold more during lower-than-average price periods. This is true not only as it relates to HLH and LLH periods during the day, but varying periods throughout a month where the Company buys during higher-than-average price periods and sells during lower-than-average price periods. As a result, the Company's purchases have been consistently higher than the average actual monthly market price, while revenues have been consistently lower than the average actual monthly market price, an outcome that is not reflected in the NPC forecast that relies on the same average market price throughout each month.[36] Additionally, the model does not

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[32] PAC/100, Dickman/23.
[33] PAC/100, Dickman/24-25; PAC/200, Graves/2-12.
[34] PAC/100, Dickman/23-24.
[35] PAC/100, Dickman/24-25; PAC/600, Graves/6-7.
[36] PAC/100, Dickman/26.

reflect actual volume of system balancing transactions because it perfectly balances the Company's load and resources to fractions of a megawatt (MW) for each hour in a single step and excludes non-physical transactions (*i.e.*, bookouts).[37]

The Company identified the deficiencies in its current modeling of actual system balancing pricing and transaction volume, and quantified the impact on NPC during 36 months ending in June 2014.[38] The impact was significant,[39] unavoidable,[40] and not properly accounted for in current NPC.[41] To address this problem and better reflect the market prices available to the Company when it transacts in the real-time market, the Company included in GRID separate prices for forecasted system balancing purchases and sales. The monthly average market prices otherwise used in GRID. [42] These are adjusted to account for the historical price differences between the Company's purchases and sales compared to the monthly average market prices. The price adjustment increases the Company's NPC by $4.3 million.[43] The Company also adjusted the model to reflect additional transaction volume to account for the use of monthly, daily, and hourly products. The additional volume component increases the Company's NPC by $3.7 million.[44]

2. The Company's use of historical data to improve the accuracy of the NPC forecast is consistent with Commission precedent.

The Company's system balancing proposal uses historical cost averages to forecast the Company's system balancing costs in 2016. It is standard ratemaking practice to use

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[37] PAC/100, Dickman/15 and 25-27.
[38] PAC/100, Dickman/26.
[39] PAC/100, Dickman/26.
[40] PAC/100, Dickman/27-28.
[41] PAC/100, Dickman/28.
[42] PAC/100, Dickman/26-27.
[43] PAC/500, Dickman/14.
[44] PAC/500, Dickman/15.

costs derived from historical averages as the basis for forecast rates.[45] This is true in the TAM, where the Commission has approved proposals using historical data to improve the accuracy of the NPC forecast.[46] For example, in 2011, the Commission approved the Company's proposal for more realistic pricing of purchase and sales transactions with hourly scalars derived from historical data. The Commission rejected ICNU's argument for the use of less granular scalars, explaining that "a key purpose of the GRID model is to determine the economic dispatch of Pacific Power's resources on an hourly basis," and the "use of hourly scalars is intended to develop results consistent with historical price data."[47]

Again in 2013, the Commission approved the Company's proposal to shape hourly wind profiles based on historical data, stating that: "We agree with Pacific Power that improving the granularity of its modeling by including actual hourly variation will represent a superior forecasting of the dispatch value of wind output than the flat blocks the company has used in previous TAM dockets."[48]

In both of these cases, parties objected to the Company's proposals because they relied on historical data and added complexity to the NPC modeling.[49] In response to the wind shaping proposal, Staff and CUB argued that consideration should be deferred to allow

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[45] *See, e.g., Re PacifiCorp*, Docket No. UE 191, Order No. 07-446 (Oct. 17, 2007) (using three-year historical average to calculate arbitrage revenue); *Re Avista*, Docket No. UG 246, Order No. 14-015 (Jan. 21, 2014) (approving stipulation using three-year historical averages to forecast uncollectible expense and rate); *Re PacifiCorp*, Docket No. UE 217, Order No. 10-473 (Dec. 14, 2010) (using historical averages to forecast insurance expense); *Investigation into Forced Outage Rates*, Docket No. UM 1355, Order No. 10-414 (Oct. 22, 2010) (using historical average to forecast outage rates); *Re Portland Gen. Elec. Co.*, Docket No. UE 197, Order No. 09-020 (Jan. 22, 2009) (using historical average to forecast employee levels); *Re Portland Gen. Elec. Co.*, Docket No. UE 266, Order No. 13-280 (Aug. 5, 2013) (approving stipulation using historical average to forecast wind generation).

[46] *See In the Matter of PacifiCorp d/b/a/ Pacific Power 2012 Transition Adjustment Mechanism*, Docket No. UE 227, Order No. 11-435 at 18-19 (Nov. 4, 2011) and *In the Matter of PacifiCorp d/b/a Pacific Power 2014 Transition Adjustment Mechanism*, Docket No. UE 264, Order No. 13-387 at 2-44 (Oct. 28, 2013).

[47] Order No. 11-435 at 19-20.

[48] Order No. 13-387 at 4.

[49] PAC/500, Dickman/18-19.

time for additional workshops and review.[50] The Commission rejected those arguments because it determined that the benefits of the improved model outweighed the concerns about complexity. The Company's proposal here is consistent with this precedent and improves the accuracy of the GRID model without adding unreasonable complexities. It is also worth noting that parties have not proposed changes to the wind shaping proposal in the two TAM filings since it was adopted.

3. PacifiCorp's proposal more accurately captures the true cost of balancing the Company's system in the short-term markets than Staff's, CUB's, or ICNU's proposals.

Staff, CUB, and ICNU oppose the Company's system balancing proposal, but do not dispute that the Company will continue to incur the same shortfall in the future or challenge how the Company calculated its historical system balancing expense (i.e., the historical difference between total purchases and sales).[51] Rejection of the Company's proposed modeling refinement would reduce NPC by approximately $8 million.[52]

a. Staff's Position

Staff agrees with the Company's rationale for both price and volume components of the proposal, as well as the need to address the fact that electricity pricing variations are not captured in the forward price curve.[53] Despite that conclusion, Staff does not want to act now.[54] While the Company appreciates that Staff agrees with the Company's rationale, PacifiCorp does not believe the complexity of the issue justifies delaying action. The model and supporting workpapers are a reflection of the Company's diverse and wide-ranging

[50] Order No. 13-387 at 3-4.
[51] PAC/500, Dickman/19-20.
[52] PAC/100, Dickman/14-15.
[53] Staff/100, Ordonez/19.
[54] Staff/100, Ordonez/23-24.

operations and the PacifiCorp took its obligation to support its proposal seriously.[55] The Company worked extensively with the parties to facilitate their understanding of the proposal and also provided a condensed version of the workpapers.[56] The Commission should act on the proposal in this proceeding.

b. CUB's Position

CUB believes PacifiCorp's proposal is a departure from weather-normalized power cost forecasting, and that the TAM is "not expected to accurately account for actual costs," so the Company's proposal should be rejected.[57] Contrary to CUB's arguments, the Company's proposal is consistent with the weather normalization of NPC and uses a multi-year rolling average, which is a common normalizing tool in preparing inputs to a NPC forecast.[58]

Furthermore, CUB's position does not address why costs that have occurred historically and are expected to occur during the forecast period should continue to be excluded.[59] As stated previously, this is contrary to the Commission precedent directing that the TAM be refined to accurately forecast actual power costs.

c. ICNU's Position

ICNU has six criticisms of the Company's proposal. As detailed below, none of these claims have merit.

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[55] PAC/500, Dickman/20-22.
[56] PAC/500, Dickman/21-22.
[57] CUB/100, Jenks-Hanhan/5-6.
[58] PAC/500, Dickman/22-23. For example, if a summer month was warmer than average, it will be reflected in an average price for that month that is higher than normal; the Company's adjustment only captures the variation of its purchase and sale prices around that higher than normal average price.
[59] PAC/500, Dickman/23.

i. The Company's proposal results in a level of sales and purchases that correspond to historical levels.

ICNU's claim that the Company's system balancing proposal would result in transaction volumes above historical levels is based on inaccurate analysis.[60] The Company's proposal includes transaction volumes to account for transactions that are equal and offsetting in terms of volume, delivery period, and locations that are "booked out" or netted together.[61] ICNU incorrectly compared these modeled results (with bookouts) to NPC actual results that exclude bookout volumes.

Contrary to ICNU's assertion, PacifiCorp's position in this proceeding is consistent with its position docket UE 245, which was that comparisons between transaction levels in actual and forecast NPC must include or exclude bookout transactions on both sides to avoid apples-to-oranges comparisons.[62] In docket UE 245, ICNU compared actual transactions with bookouts to forecast transactions without bookouts. In this case, ICNU did the opposite (i.e., it compared actual transactions without bookouts to forecast transactions with bookouts). In both cases, ICNU's analysis was misleading.

ii. The Company's proposal is not predicated on a bias between forward and spot market prices.

ICNU contends that the system balancing proposal is theoretically invalid because it assumes there is bias between forward and spot market prices.[63] On the contrary, the Company's proposal does not quantify changes in price between a forward period and the spot market for the same transaction.[64] Instead, the Company's adjustment calculates the difference in realized prices for transactions during a month versus the average market price

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[60] ICNU/100, Mullins/12-15.
[61] PAC/500, Dickman/25-27.
[62] PAC/500, Dickman/28.
[63] ICNU/100, Mullins/10.
[64] PAC/500, Dickman/28-29; PAC/600, Graves/2-9.

over that same month, and applies that differential to short-term system balancing transactions in GRID. The average realized price of the Company's transactions is dependent on the timing of each transaction within the month.[65] ICNU accepts the fact that pricing varies based on timing differences, yet dismisses the fact that a forward market does not provide a product precisely shaped to the Company's purchase position and/or sales position for a month.[66]

iii. The historical transactions on which the Company's adjustment is based are not hedging transactions.

ICNU's claim that the Company's proposed system balancing costs are a result of forward hedging transactions and thus incorporate historical losses between the forward and prompt period is incorrect.[67] Hedging occurs when the Company closes a portion of its open position at a fixed price, rather than waiting and closing it a future market price.[68] PacifiCorp's proposal is based on the cost of balancing transactions done in the daily and hourly markets and accounts for the timing of these transactions as they are executed to balance the system.[69] The Company's adjustment does not determine the quantity or cost of forward hedging transactions during the test period.[70]

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[65] PAC/500, Dickman/16 and 29. If the Company's purchases occur during higher priced periods within the month, the average price of such purchases will be higher than the flat market average for that month.

[66] ICNU/100, Mullins/16.

[67] ICNU/100, Mullins/11-12.

[68] PAC/500, Dickman/30-31. ICNU's argument that it is appropriate to impute a larger volume of sales than purchases is based on its claim that the proposed system balancing adjustment relates to hedging transactions. ICNU is correct that the Company's hedging reports indicate that it generally has entered into twice the volume of hedging contracts for sales than for purchases. But this is irrelevant to the Company's proposal, which is based on balancing transactions, not hedges.

[69] PAC/600, Graves/9-10.

[70] PAC/500, Dickman/30-31.

iv. The Company's proposal does not attempt to measure or impose bid-ask spreads.[71]

The Company's adjustment measures the difference between the actual prices for hourly and daily market transactions and the historical daily market prices.[72] As ICNU concedes,[73] the weighted average price in the periods the Company was a purchaser is not the same as the weighted average price for those periods when the Company was a seller and therefore the Company's proposal is not consistent with the definition of bid-ask spread.[74]

ICNU's claim that the Company's adjustment is flawed because it results in a "negative bid-ask spread" is also misguided because PacifiCorp does not model bid-ask spreads.[75] The fact that in some months the Company was able to sell power during higher average price times and purchased power in lower average price times is merely a reflection that PacifiCorp sometimes has generation resources that the Company can dispatch to meet its load requirement and make economic sales.[76] The Company's proposal already reflects the benefits from these periods in the amount of approximately $3 million per year on a total company basis.[77]

v. Other Northwest utilities make adjustments similar to PacifiCorp's proposal.

Idaho Power Company (Idaho Power) makes a modeling adjustment to its power cost model (AURORA) results used to set rates in Oregon, adjusting the prices of purchased

[71] PAC/500, Dickman/32-33. A bid-ask spread is the difference between the highest price that a buyer is willing to pay for an asset and the lowest price for which a seller is willing to sell it. A key component of the definition is that the buyer and seller are bidding on the same asset, i.e., the buyer and seller are bidding in the same market at the same time.
[72] PAC/600, Graves/10-11.
[73] ICNU/100, Mullins/16.
[74] PAC/500, Dickman/32-33. The buyer and seller are bidding in the same market at the same time.
[75] PAC/500, Dickman/33-34.
[76] PAC/500, Dickman/33-34.
[77] PAC/500, Dickman/34.

power and wholesale sales compared to forecasted monthly market prices.[78] Like PacifiCorp's proposal, the adjustments to Idaho Power's transaction pricing are based on the assumption that Idaho Power sells its excess power during lower-priced times and purchases power during higher-priced times.[79] This adjustment was approved by the Commission in Order No. 08-238.[80] Idaho Power continues to include this adjustment in its power supply expense filings.[81]

PGE has included an assumed super-peak purchase power contract in its power cost forecasts for several years.[82] The cost of the modeled contract exceeds the monthly Mid-Columbia HLH price, which is comparable to the outcome of the Idaho Power adjustment and the Company's proposal in this docket with respect to increasing the modeled cost of short-term purchases.

vi. The Company's inter-hour wind and load integration charges do not capture the costs associated with balancing the Company's system.

ICNU incorrectly claims that the Company is already recovering system balancing costs through its inter-hour wind integration costs. The studies on which the inter-hour integration costs are based use the same hourly price forecasts now used in GRID, which are

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[78]PAC/500, Dickman/34-36.

[79] *Re Idaho Power Co. Request for General Rate Revision*, Docket No. UE 167, Order No. 05-871 at 8 (July 28, 2005). The stipulation that included the re-pricing also approved a PCAM for Idaho Power, with dead bands, sharing bands, and an earnings test similar to the Company's current mechanism. This fact suggests that the parties to that stipulation, which included Staff and CUB, did not view that the costs addressed by the re-pricing were intended to be subject to the PCAM's dead bands.

[80] *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 08-238, App. A at 3-4 (Apr. 28, 2008).

[81] PAC/500, Dickman/35. *See e.g. Re Idaho Power Co. 2015 Annual Power Cost Update*, Docket No. UE 293, Idaho Power/100 Wright/6-7 (Oct. 21, 2014).

[82] *See, e.g., Re Portland General Electric Co. 2015 Annual Power Cost Update Tariff*, Docket No. UE 208, Order No. 09-433 at 3 (Oct. 30, 2009).

uniform across each month.[83] The integration costs do not measure the costs associated with balancing the Company's system on a real-time basis and do not overlap with the system balancing costs captured by the Company's proposal.

4. ICNU's system balancing/market caps adjustments are unreasonable.

In response to the Company's system balancing proposal, ICNU proposes two adjustments related to market caps. First, ICNU proposes that if the Commission adopts the Company's system balancing proposal, the Commission should also eliminate the Company's market cap adjustment.[84] This issue was fully litigated in the 2013 TAM, where the Commission concluded that some form of market caps was required to produce a reasonable forecast.[85] ICNU does not offer any reason for the Commission to reconsider its decision. Removal of market caps would decrease the modeled costs of PacifiCorp's system balancing transactions by imputing unrealistic sales volumes in illiquid markets.[86] This is directly contrary to PacifiCorp's system balancing proposal, designed to model the true costs of system balancing in NPC, based on historical averages.

In the alternative, ICNU proposes a second adjustment that replaces the Company's proposal with a $0.50/MWh spread between purchases and sales and eliminates market caps.[87] This proposal is based on ICNU's erroneous claim that the Company's proposal

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[83] PAC/500, Dickman/37-39.

[84] ICNU/100, Mullins/19.

[85] Order No. 12-409 at 7. Market caps are designed to impose liquidity constraints on the GRID model to prevent GRID from artificially increasing sales, especially to illiquid and high-priced markets.

[86] PAC/500, Dickman/39-40. Removal of market caps results in a 10 percent increase in the total sales now modeled in this case (including the transactions added to NPC to better simulate total transaction levels resulting from standard blocks transactions). ICNU's approach, without market caps, is approximately seven percent over historical levels (including bookouts).

[87] ICNU/100, Mullins/19-20.

models a bid-ask spread.[88] ICNU's proposal would reduce the Company's NPC by $1.69 million.[89]

ICNU's proposal is a step backwards in terms of addressing the short-term transaction costs and market liquidity issues the Company faces in balancing its system. ICNU's adjustment would result in a huge overstatement of the Company's short-term market sales. The elimination of market caps would artificially result in a 10 percent increase in sales volumes and the bid-ask spread adjustment would then increase sales by an additional 18 percent.[90] Instead of addressing PacifiCorp's cost recovery for system balancing, ICNU's proposal dramatically overstates sales and would result in a less accurate model.

C. The Company's Modeling Accurately Reflects the EIM Benefits Expected during the Test Period.

1. Inter-regional EIM Dispatch Benefits

a. The Company properly accounted for the benefits of the EIM.

The Initial Filing reflected EIM benefits[91] from inter-regional dispatch based on actual results from December 2014 and January 2015 because this was the most recent, representative actual data available at the time NPC was prepared.[92] ICNU and CUB criticized the Company's use of two winter months as not being representative of the actual benefits that will occur from a full year of EIM participation, including concerns that the modeling did not properly account for the benefits resulting from the participation in the EIM

[88] PAC/500, Dickman/40-42.
[89] ICNU/100, Mullins/20.
[90] PAC/500, Dickman/41.
[91] PAC/500, Dickman/56. EIM benefits are comprised of export and import benefits. The export benefit is the difference between the export revenue and the expense of the Company generation assumed to be dispatched to support the transaction. The export benefit is also tied to the transmission capacity available for EIM transactions in each month of the forecast period. The import benefit is the difference between the import expense and the expense of the Company generation that would have been dispatched but for the transaction.
[92] PAC/500, Dickman/56; PAC/100, Dickman/9-10 and 13. The EIM is a real-time balancing market that optimizes generator dispatch every five and 15 minutes within and between the PacifiCorp and the California Independent System Operator Corporation (CAISO) balancing authority areas (BAAs).

of NV Energy, Puget Sound Energy (PSE), and Arizona Public Service (APS).[93] In its cross-answering testimony, Staff indicated support for these positions unless the Company updated its filing to address them.[94]

To respond to these concerns, the Company's Reply Update incorporates seven months of historical data from the EIM through June 2015.[95] Additionally, until further historical information is available, PacifiCorp provided greater weight to the June 2015 results to address the seasonality concerns (i.e., the Company based the forecasted EIM benefits for the months of June through September on the June 2015 results, and the remaining forecasted months used the average from December 2014 through May 2015).[96] The Company's proposal provides a reasonable estimate of any seasonal impact on EIM inter-regional benefits for the forecast period.

The Company also increased its EIM inter-regional dispatch benefits to account for the participation of NV Energy, PSE, and APS in the EIM in 2016.[97] Including updates to the EIM reserve benefits discussed below, the 2016 TAM now includes $12.4 million in EIM benefits on a total company basis, or approximately $3 million on an Oregon-allocated basis.[98] This increases the EIM benefits in the Initial Filing by $3.0 million on a total company basis or $800,000 on an Oregon-allocated basis.[99]

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[93] ICNU/100, Mullins/35-36; CUB/100, Jenks-Hanhan/8-10.

[94] Staff/200, Ordonez/3.

[95] PAC/500, Dickman/57-58. The Company intends to reflect results through September 2015 in its Final Update.

[96] PAC/500, Dickman/61-62. The Company's Final Update will incorporate EIM benefit results through September 2015. At that time, the Company will have actual results for all of the summer months during 2015 and ten out of twelve months in a calendar year. The Company's forecast for June through September 2016 would be based on the average results from these four summer months, while the forecast for the remaining months will be based on the average results in the six other months.

[97] PAC/500, Dickman/63-71.

[98] PAC/500, Dickman/56.

[99] PAC/500, Dickman/12.

b. ICNU's EIM inter-regional dispatch adjustments are unreasonable.

The Company's Reply Update reasonably addressed the issues of seasonality and the participation of new EIM participants. ICNU's seasonality proposal contains incorrect operational assumptions[100] and formula errors.[101] For example, ICNU assumes the EIM export volumes will be identical in each month of the forecast period, whereas the Company's proposal included volumes based on the transmission available for EIM transfers in each month of the forecast period.[102]

The Company's proposal also accurately accounts for new EIM participants, while ICNU's proposal overstates the potential benefits. The Company agrees in principle that there will be additional inter-regional dispatch benefits once NV Energy, PSE, and APS join the EIM. [103] The dispute is the proper way to accurately account for those benefits. The Company calculates benefits from the addition of NV Energy to the EIM using the same approach as used for the inter-regional exports between PacifiCorp and the CAISO, but with reduced margins to reflect diminishing returns from incremental transmission capacity.[104] The Company's calculation results in total-Company benefits of $1.5 million resulting from NV Energy's participation in the EIM.[105]

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[100] PAC/500, Dickman/59. ICNU's adjustment is based on the flawed assumption that the spread between market prices in Oregon (Mid-C) and the California-Oregon Border (COB) is representative of the benefits that will be achieved in any particular month. In fact, the export benefits in December 2014 through June 2015 were negatively correlated with the Mid-C-COB price spread; when the spread was higher, the Company's overall export benefit was lower.

[101] PAC/500, Dickman/59. ICNU's calculation of the import margin also appears to be understated by roughly 80 percent due to a formula error.

[102] PAC/500, Dickman/59.

[103] PAC/500, Dickman/63.

[104] PAC/500, Dickman/64-65. The E3 Study, which estimated inter-regional EIM benefit results, calculated benefits to existing participants that were just 21 percent more than the level achieved between the Company and the CASIO alone.

[105] PAC/500, Dickman/64.

ICNU's proposal, while similar, is flawed because it wrongly assumes the incremental benefits from exporting to new EIM participants will be essentially the same as the Company's current benefits when exporting to the CAISO,[106] and ICNU overstates the Company's transfer capability by failing to account for the Company's transmission already utilized in the forecast period.[107]

Regarding PSE and APS, the Company calculates the benefits based on the Energy and Environmental Economics (E3) studies for PSE and APS, which estimated total annual benefits to all existing participants (CAISO, PacifiCorp, and NV Energy) of $2 million per year.[108] PacifiCorp allocated these benefits among the existing participants based on the same ratios employed by ICNU with regard to the flexibility reserve diversity benefits from these participants.[109] PacifiCorp's proposal results in benefits of $83,000 over the three months that PSE and APS are in the EIM.[110]

ICNU's proposed benefits related to APS and PSE are grossly overstated. ICNU estimates benefits to PacifiCorp alone of $4.4 million per year, even though the E3 studies for APS and PSE estimated total benefits for all existing participants of only $2 million per year.[111] This significant discrepancy demonstrates that ICNU's proposed adjustment is unreasonable.

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[106] PAC/500, Dickman/64-70. ICNU incorrectly applied the historical margin per available transmission capacity to the assumed volume of energy exports rather than the volume to transmission available. Correcting this error would have tripled ICNU's proposal to $6.3 million per year in benefits associated with NV Energy, and to $3.3 million for PSE and APS, while previous studies indicated far less of an impact. The magnitude of these results demonstrates that ICNU's approach produces entirely unreasonable results when it is correctly applied.
[107] PAC/500, Dickman/65-66 and 70-72.
[108] PAC/500, Dickman/63.
[109] PAC/500, Dickman/63. Flexibility reserve diversity benefits are detailed in a later section.
[110] PAC/500, Dickman/63-64.
[111] PAC/500, Dickman/63.

c. CUB's proposal to defer EIM benefits is unnecessary and unworkable.

Because of the dearth of historical EIM data in the Company's Initial Filing, CUB proposed to defer EIM benefits rather than attempt to forecast them.[112] The Company's inclusion of additional EIM data and benefits in its Reply Update directly addresses CUB's underlying concern. In any event, it is not clear that EIM benefits could be carved out and addressed in the later docket as CUB proposes because the total Company EIM benefit includes inter-regional benefits, as well as reserve diversity benefits. These benefits are not specifically identified in actual NPC results and could be difficult to quantify for later true up.[113]

d. Staff's new EIM adjustment is untimely and unsupported.

In cross-answering testimony, Staff proposed a new adjustment to capture EIM inter-regional dispatch benefits allegedly resulting from the Company's increased dynamic transfer capability between its Balancing Area Authorities (BAAs). This proposal results in an additional $4.2 million in system-wide inter-regional EIM benefits, or $1.07 million in Oregon-allocated benefits.[114]

Staff's adjustment is procedurally improper. In cross-answering testimony, Staff should not be permitted to substitute an entirely new adjustment for EIM inter-regional benefits simply because Staff decided to withdraw its adjustments related to intra-hour EIM

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[112] CUB/100, Jenks-Hanhan/9-10.

[113] PAC/500, Dickman/72-73.

[114] Staff/200, Ordonez/2 and 5-10. Staff learned that its reliance on a 30-minute balancing market for its adjustment was not yet operational and therefore Staff withdrew its EIM within-hour benefits adjustment. Staff also withdrew its reserve adjustment associated with the increase in dynamic transfer capability.

benefits and dynamic transfer capability reserve savings raised in Opening Testimony.[115] Allowing a new adjustment at this stage of the case is prejudicial to PacifiCorp.

Staff's new adjustment is also based on unproven assumptions that are contrary to historical evidence. Staff contends that the Company's inter-regional EIM dispatch benefits will increase by 50 percent because the Company's dynamic transfer capability between its BAAs has doubled (increasing from 200 MW to 400 MW).[116] Staff reasons that the Company's EIM export benefits rely on its dynamic transfer capability between its BAAs because the Company's marginal resources are located in the east balancing area and must therefore be dynamically transferred to the west balancing area before being exported to CAISO. Without the limitation of 200 MW of dynamic transfer capability, Staff claims that the Company will realize a significant increase in export benefits, resulting in greater inter-regional dispatch benefits.

Staff's adjustment incorrectly assumes that additional dynamic transfer capability between balancing areas will be used for EIM exports, ignoring the fact that the Company also uses its dynamic transfer capability for intra-regional transfers (i.e., the least cost balancing of the Company's own resources). These intra-regional transfers are already modeled in GRID because GRID optimizes the balance of all of the Company's resources and market transactions across its entire system without regard for intra-hour limitations.

Based only on current coal prices, Staff's adjustment also assumes that the marginal resources being exported to CAISO are the Company's coal plants in the east balancing

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[115] Staff/200, Ordonez/5-10.

[116] Staff appears to claim that the benefits could double if the entire 200 MW of dynamic transfer capability were used for inter-regional EIM transfers. Staff's adjustment is based on its assumption that only 50 percent of the increased capacity will be used to produce exports to CAISO. Staff/200, Ordonez/6 and 10.

authority area.[117] This assumption is questionable because the marginal energy cost of the Company's coal and natural gas units are similar. Additionally, Staff fails to consider that all exports to the CAISO incur a greenhouse gas (GHG) cost, which makes the Company's natural gas plants less expensive than its coal plants for EIM dispatch purposes. Historical EIM results show that transfers from PacifiCorp's east-side have only supplied about one-half of the EIM exports to CAISO, further undermining Staff's assumption that east-side coal plants comprise the entirety of EIM exports.

Staff's adjustment also incorrectly assumes a linear relationship between additional transmission capacity and additional EIM benefits. As the Company testified in response to ICNU's adjustment for new participants, all E3 studies on the EIM and the Company's own historical EIM experience show diminishing returns on EIM export benefits associated with increased transmission capacity.[118] This is true for several reasons. First, because additional dynamic transfers represent an increased volume over current EIM exports, these additional exports will necessarily come from higher cost generators on the Company's system than the existing exports, with lower realized margins. Second, increased transmission capacity does not necessarily mean the new capacity will be used because CAISO may frequently be able to meet its demand with the Company's existing exports. Third, the incremental export volume will result in displacement of the CAISO resources with lower marginal costs, reducing the market clearing price and the revenues associated with the Company's existing exports. Fourth, the Company's forecast already reflects benefits from EIM exports to NV

[117] Staff/200, Ordonez/9.
[118] PAC/500, Dickman/64-72.

Energy and these exports will reduce the resources available to support additional transfers across the dynamic transfer capability for export to the CAISO.[119]

2. Regulation Reserves

a. PacifiCorp's adjustments to regulation reserves improve the accuracy of the GRID model.

In its Initial Filing, the Company improved its NPC modeling by making two adjustments to regulation reserves. First, the Company included flexibility reserve benefits resulting from the Company's participation in the EIM.[120] Second, the Company recommended modeling regulation reserve requirements on an hourly basis, rather than using flat monthly amounts.[121] In its Reply Update, the Company reflected additional reserve savings from NV Energy's participation in the EIM and accepted ICNU's adjustment to increase the flexibility reserve benefits associated with the future participation of PSE and APS in the EIM. [122]

b. ICNU's regulation reserve adjustments are unreasonable.

Both of ICNU's adjustments to regulation reserve are inappropriate.[123] The larger proposal, based on the Company's Critical Performance Standards 2 (CPS2) score, cuts regulation reserve by more than one-third and reduces NPC by $2.8 million.[124] ICNU claims that the Company calculates its regulation reserve requirement assuming 99.7 percent

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[119] PAC/500, Dickman/64.
[120] PAC/500, Dickman/43.
[121] PAC/500, Dickman/43.
[122] PAC/500, Dickman/43.
[123] ICNU/200, Mullins/1. In cross-answering testimony ICNU withdrew its third regulation reserve adjustment regarding interruptible loads.
[124] PAC/500, Dickman/47. CPS2 is a measure of how often the Company remains within the specific reliability standard adopted by NERC. CPS2 states that a balancing authority shall operate such that its average area control error is within its L_{10} limit (a threshold determined by NERC) for at least 90 percent of clock-ten-minute periods (six non-overlapping periods per hour) during a calendar month.

reliability, while in actual operations the Company has a much lower reliability percentage, as reflected in the Company's lower CPS2 score.[125]

The Company is no longer required to meet the CPS2 requirement and its CPS2 score is irrelevant to its current regulation reserve requirement.[126] The Company now operates under the Reliability-Based Control (RBC) Proof-of-Concept Field Trial under Project 2007-18 for the Western Electricity Coordinating Council.[127] The change in the Company's reliability regulation has resulted in a lower CPS2 score not because the RBC requirements demand less total reserves, but because RBC accounts for deviations in a different manner.[128]

The Company's reliability studies indicate that the Company may need to consider more regulation reserves, not less, to maintain compliance with the RBC standard in the future.[129] ICNU's proposal to reduce regulation reserves fails to accurately capture the costs of compliance with the RBC standard and undermines the Company's important reliability compliance efforts.

ICNU's other adjustment to regulation reserves is related to dynamic transfers between BAAs and reduces NPC by $0.3 million.[130] This proposal is based on the inaccurate assumption that the Company's increased dynamic transfer capability and participation in the EIM results in greater ability to transfer flexibility reserve requirements between its BAAs.[131] There is no mechanism by which flexibility reserves can be transferred between the

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[125] ICNU/100, Mullins/23.
[126] PAC/500, Dickman/50.
[127] PAC/500, Dickman/48.
[128] PAC/500, Dickman/50.
[129] PAC/500, Dickman/52.
[130] ICNU/100, Mullins/31-33.
[131] PAC/500, Dickman/54.

Company's BAAs under the EIM.[132] Staff implicitly recognized this fact in dropping its reserve sharing adjustment.[133] ICNU's reserve benefits are highly speculative and do not take into account costs for potential reserve shortages or transmission limitations.[134] ICNU's adjustment is also mutually exclusive with Staff's new EIM adjustment, which assumes a different (but equally implausible) use of additional dynamic transfer capability.

D. Hermiston PPA Expiration

The Company opted not to renew the Hermiston PPA for an additional ten year term based on the forecasted costs and benefits at the time PacifiCorp made its decision. In particular, the PPA is very expensive,[135] and is not needed to meet load on either the east or west side of PacifiCorp's system for several years.[136] Staff addressed this issue in cross-answering testimony and concluded that renewal of the PPA would have been onerous to the Company and ratepayers, increasing NPC in this case by approximately $3 million.[137]

While ICNU contends that the Company was imprudent in terminating the PPA, it nevertheless includes the termination benefit of $3 million in its recommended NPC.[138] ICNU's imprudence argument lacks any evidentiary foundation, and ICNU's criticism of the Company's integrated resource plan (IRP) analysis is simply wrong.[139]

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[132] PAC/500, Dickman/54-55. The Company can transfer contingency reserves from one BAA to the other, however, such transfers must be scheduled in advance across a path with dynamic transfer capability, which is then no longer available for use within the EIM.
[133] Staff/200, Ordonez/2.
[134] PAC/500, Dickman/55-56.
[135] PAC/500, Dickman/75. Inclusion of the PPA for the last six months of 2016 in this TAM filing would increase NPC by approximately $3.0 million.
[136] PAC/500, Dickman/74-75.
[137] Staff/200, Ordonez/22.
[138] PAC/500, Dickman/76.
[139] PAC/500, Dickman/74-76.

ICNU also seeks a disallowance of the costs of point-to-point transmission previously used for the Hermiston PPA.[140] ICNU's adjustment is inappropriate because, even with the expiration of the Hermiston PPA, the transmission contract still provides a useful transmission path for resources other than the Hermiston PPA. Additionally, the Company was contractually required to terminate or enter into the transmission contract nine months before the renewal deadline of the Hermiston PPA.[141] The Company was required to enter into a contract with a five-year term to maintain its roll-over rights, which provide the Company the valuable option of renewing the contract at the end of the five-year term.

E. Outage Rate Modeling

In this case, the Company modeled thermal plant forced outages and unit de-rates as discrete events, rather than applying a uniform de-rate to the plant operating characteristics across all hours.[142] In addition, because outages are no longer modeled as de-rates, the Company removed the corresponding adjustments to heat rates and minimum operating levels.[143] ICNU rejected this refinement and instead recommends that the Company continue to use the methodology adopted by the Commission in docket UM 1355, which would reduce NPC by $0.2 million.[144]

Staff supported ICNU's position in cross-answering testimony based on concerns about deviating from the Commission's order in docket UM 1355.[145] But the Commission expressly acknowledged in that order that its approved methodology was imperfect and

[140] ICNU/100, Mullins/42-43.
[141] PAC/500, Dickman/77.
[142] PAC/100, Dickman/30-31.
[143] PAC/500, Dickman/77.
[144] ICNU/100, Mullins/43-45.
[145] Staff/200, Ordonez/4.

parties should explore refinements in future NPC cases.[146] It is impractical to limit changes in outage rate modeling to major generic investigations and it is contrary to the Commission's express statements in docket UM 1355.

While ICNU contests the outage modeling refinement in this case, its witness has proposed use of the identical methodology in the Company's currently pending Wyoming rate case. As Mr. Mullins implicitly acknowledges in supporting this approach in Wyoming, the Company's proposed pattern of outages is a much better simulation of the Company's actual outage patterns than the existing methodology, which assumes every single plant will be partially available in every single hour.[147] PacifiCorp's proposal eliminates outages that are less than two hours long and shortens the length of outages, which eliminated 12 percent of the short outage events in the historical period.[148] In the GRID model, unlike the real world, more frequent outages are not necessarily more costly.[149]

F. Wind Generation

The Company made two refinements to its modeling of wind generation. First, the Company reduced generation output at its Glenrock and Seven Mile Hill wind sites to reflect expected energy lost from compliance curtailment for avian protection.[150] Second, the Company modeled generation from the Company's wind PPAs to match the levels in the 48-month historical period.[151] ICNU opposes both of these refinements and argues that the Company should be required to use the modeling assumptions that were originally used to

[146] Order No. 10-414 at 7.
[147] PAC/500, Dickman/78.
[148] PAC/500, Dickman/79.
[149] PAC/500, Dickman/79.
[150] PAC/100, Dickman/39-40.
[151] PAC/500, Dickman/79. For those projects with less than 48 months of history, the project owner's forecast was used for the period when actual results were not available.

justify the wind facilities, claiming that the modeling adjustment results in an immaterial amount.[152]

The Commission previously rejected ICNU's proposal in docket UE 200:

> 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.[153]

ICNU has not acknowledged this precedent, nor has it provided any legitimate reason why the Commission should deviate from it in this case. ICNU also contradicts its own position in other proceedings where ICNU has argued for the most up-to-date information when establishing a capacity factor for a wind project,[154] and supported use of a five-year rolling average to forecast wind generation previously.[155]

G. Direct Access

Noble Solutions makes three recommendations regarding direct access issues in this case.[156] Noble Solutions' first recommendation is that the Schedule 294, 295, and 296 transition adjustments be adjusted to reflect the value of freed-up RECs resulting from the departure of the direct access load. This position is based on the mistaken assumption the Company sells RECs that are freed up once its load decreases due to departing direct access

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[152] PAC/500, Dickman/80. The adjustment results in a $52,000 decrease to NPC.
[153] *Re PacifiCorp 2009 Renewable Adjustment Clause Schedule 202*, Docket No. UE 200, Order No. 08-548 at 21 (Nov. 14, 2008).
[154] PAC/500, Dickman/80-81 and *see also In the Matter of Portland General Electric Company's Net Variable Power Costs and Annual Power Cost Update*, Docket No. UE 286, ICNU/100, Mullins/15-18 (May 27, 2014).
[155] PAC/500, Dickman/82. *See also In the Matter of Portland General Electric Company's Net Variable Power Costs and Annual Power Cost Update*, Docket No. UE 266, Order No. 13-280 (Aug. 5, 2013).
[156] PAC/500, Dickman/83-86.

customers.[157] In reality, the Commission requires the Company to bank unused RECs and use them for future RPS compliance.[158]

The Commission has rejected similar adjustments proposed by Noble Solutions purporting to capture the value of freed-up assets.[159] Most recently, in docket UE 267, the Commission again "rejected potential transition adjustment credits for the resale of BPA transmission," finding "no compelling evidence of PacifiCorp's actual ability to sell BPA transmission rights when direct access loads depart and then repurchase such rights when direct access loads returns."[160] Here, Noble Solutions has likewise failed to produce compelling evidence that the Company will actually be able to sell RECs freed-up by departing direct access load. Finally, if a benefit did occur from the sale of freed up RECs, it is unnecessary to include that revenue as a transition credit because those revenues are passed back to all customers through the property sales balancing account.[161]

The Commission has also previously rejected Noble Solutions' second recommendation, proposing that the Consumer Opt-Out Charge included in the Company's Five-Year Transition Adjustment should decrease, rather than increase, in years six through 10.[162] Like the Company's filing in docket UE 267, the proposed Consumer Opt-Out Charge properly escalates the Company's fixed generation costs at the average rate of inflation—meaning that, in real terms, the fixed generation costs are held constant through year 10.[163]

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[157] Noble Solutions/100, Higgins/16-17.

[158] *See In the Matter of PacifiCorp, dba Pacific Power, Application for Sale of Renewable Energy Credits*, Docket No. UP 266, Order No. 11-512 (Dec. 20, 2011).

[159] PAC/500, Dickman 83-84. Order No. 12-409 at 17; Order No. 13-387 at 13-14; *Re PacifiCorp Transition Adjustment, Five-Year Cost of Service Opt-Out*, Docket No. UE 267, Order No. 15-060 at 9 (Feb. 24, 2015), reconsideration denied, Order No. 15-195 (June 16, 2015).

[160] PAC/500, Dickman/83-84. BPA stands for Bonneville Power Administration.

[161] PAC/500, Dickman/84.

[162] Noble Solutions/100, Higgins/24.

[163] PAC/500, Dickman/84-86.

Noble Solutions requested that the Commission reconsider its decision in docket UE 267 rejecting the recommendation to decrease the Consumer Opt-Out Charge in years six through 10, and the Commission denied the request.[164] The Commission made it clear that if a party wanted to challenge how the Consumer Opt-Out Charge was calculated in the future, they must have new evidence or arguments to do so.[165] Noble Solutions has failed to meet this standard.

Noble Solutions' final recommendation addresses the treatment of electric service suppliers (ESS) that submit a Direct Access Service Request (DASR) after the deadline, which is 13 days before January 1.[166] The tariff sets the deadline,[167] but Noble Solutions is concerned that it results in different treatment under the five-year opt-out program compared to PacifiCorp's other direct access programs and that there is ambiguity as to how a customer will receive service if the ESS submits a late DASR.[168]

There is no ambiguity as to how a five-year opt-out customer will be served if a DASR is received after the cut-off date for service beginning January 1.[169] The Company's testimony in docket UE 267 expressly addressed this issue.[170] If a customer opts out, but the Company does not receive a DASR by the appropriate time to allow the ESS to provide service beginning on January 1, the customer's opt-out election reverts to the one-year program, Schedule 294.

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[164] PAC/500, Dickman/84-86. *See also Re PacifiCorp's Transition Adjustment, Five-Year Cost of Service Opt-Out*, Docket No. UE 267, Order No. 15-195 at 2 (June 16, 2015).
[165] PAC/500, Dickman/84-86. *See also* Order No. 15-195 at 3.
[166] Noble Solutions/100, Higgins/26.
[167] *See* Advice No. 11-002, Original Sheet No. R21-7 (effective Mar. 22, 2011).
[168] PAC/800, Ridenour/2-3.
[169] Advice No. 13-004, Original Sheet No. 296-3 (Feb. 28, 2013).
[170] PAC/800, Ridenour/2-3 and *see also* Docket No. UE 267, PAC/300, Steward/11-12 (Mar. 27, 2014).

The Company's five-year opt-out program is treated differently than the one- and three-year programs because customers pay transition adjustments for the five-year period but are then no longer subject to transition adjustments and would pay less than the full five years of transition adjustments commencing after January 1, including the customer opt-out charge.[171] The five-year opt out program is also treated differently because it is limited to a total of 175 aMW, so it is important to monitor the program.[172]

If the Commission does decide to allow direct access customers and ESSs leeway to miss the enrollment deadline, it should only do so subject to the following conditions: (1) the customer pays the difference between the transition adjustments paid under Schedule 220/294 and the transition adjustment plus the consumer opt-out charge under Schedule 296; (2) service from the ESS begins no later than February 1; and (3) the Company receives the completed DASR from the ESS no later than 13 days before the commencement of service from the ESS.[173]

III. CONCLUSION

For the reasons set forth above, PacifiCorp respectfully requests that the Commission approve PacifiCorp's 2016 TAM and allow a rate increase of $12.4 million, subject to the TAM Final Update on November 15, 2015. The purpose of this filing is to forecast the Company's 2016 NPC as accurately as possible. The Commission can accomplish this by

[171] PAC/800, Ridenour/3-4.
[172] PAC/800, Ridenour/4.
[173] PAC/800, Ridenour/5-6.

approving the Company's overall NPC forecast as reasonable and rejecting the parties' proposed adjustments.

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