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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 Opening Brief.

Please contact this office with any questions.

Very truly yours,

Katherine McDowell

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BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

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

PACIFICORP'S OPENING BRIEF

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UE 296

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

I. INTRODUCTION

PacifiCorp d/b/a Pacific Power (PacifiCorp or Company) respectfully submits this Opening Brief to the Public Utility Commission of Oregon (Commission). The Company has presented substantial evidence supporting its requested rate increase of approximately $12.4 million, or 1.0 percent overall.[1] Following briefing and a hearing, this case has distilled to three primary issues—the Company's net power costs (NPC) modeling of system balancing costs, regulating reserves, and Energy Imbalance Market (EIM) benefits. The Company's approach to each of these issues is reasonable and well-supported.

For the first time, the Company's modeling of system balancing costs in this case reasonably forecasts the actual costs of transacting in the day-ahead and hourly markets. Previously, the Company modeled the same hourly average prices for each weekday within a given month, even though undisputed historical evidence shows that purchase prices systematically exceed sales prices.[2] In the past, the Company also modeled purchases and sales to match the Company's exact needs, without reflecting the market's standard 25 megawatt (MW) transaction block.[3] The Company's system balancing proposal corrects these inaccuracies by including separate purchase and sale prices in the forward price curve

[1] PAC/500, Dickman/5. This forecast is subject to a final update in November 2015.
[2] PAC/100, Dickman/23, 27-28.
[3] PAC/100, Dickman/23-24.

and adding transactions and costs to account for standard block purchases and sales. These new, more granular modeling inputs are derived from a rolling, multi-year average of the Company's historical data, similar to many other costs modeled in NPC.[4]

The Company's system balancing proposal responds directly to the Commission's instructions to more accurately model NPC, while mitigating rate impacts on customers.[5] Indeed, the 2016 TAM provides an opportunity to implement this major modeling improvement with only a modest rate increase because of significant cost savings from the Company's participation in the EIM and the expiration of high cost power purchase agreements (PPAs), including the Hermiston PPA.

The second major issue in this case is whether the Company reasonably established the regulating reserves required to comply with the North American Electric Reliability Corporation's (NERC) reliability standards and ensure safe and reliable service. The Industrial Customers of Northwest Utilities (ICNU) claims that the Company carries excessive reserves and proposes to slash reserves by 44 percent—using a 90 percent confidence interval instead of the Company's current 99.7 percent confidence interval.[6] No other party supports this radical adjustment, which misleadingly relies on an outdated reliability standard (CPS2). It is undisputed that the reserves modeled in this case are those the Company actually carries to support its operations and comply with its current NERC reliability standard (BAAL). The Company's adoption of a 99.7 percent confidence interval was fully analyzed and documented in its 2012 and 2014 wind integration studies, and it is

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[4] PAC/500, Dickman/14-15, 18.

[5] PAC/500, Dickman/17-18; *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).

[6] ICNU/100, Mullins/28; PAC/500, Dickman/46-47 (ICNU recommends reserve decrease of 245 MW); PAC/500, Dickman/67 (Company modeled 560 MW of regulating margin).

aligned with other regional utilities, including the Bonneville Power Administration (BPA). ICNU's adjustment undermines reliability, a fact that warrants its rejection.[7]

The third major issue is whether the Company has reasonably modeled the benefits resulting from the Company's participation in the EIM. The Company's Reply Update responded to other parties' EIM testimony, leaving only a few outstanding issues. After the final update, the EIM benefits in this case will be based on nearly a full year of actual data and reflect both dispatch and reserve benefits from new EIM participants.

Staff acknowledged that the Company's modeling of EIM benefits was reasonable, but added a new adjustment in cross-answering testimony to impute EIM dispatch benefits from the Idaho Power Company (Idaho Power) asset exchange. Staff did not realize that the TAM already reflects benefits from the Idaho Power asset exchange (in the form of reduced wheeling costs), and the key assumption on which Staff's new adjustment is based in demonstrably wrong.[8] While ICNU continued to support certain EIM adjustments in its prehearing memorandum, at hearing ICNU's witness conceded that these adjustments were overstated.[9]

In summary, the record in this case supports approval of the one percent rate increase presented in the 2016 TAM. In particular, the Commission should approve the Company's system balancing proposal as a modeling improvement that increases the accuracy of the NPC forecast and helps address the Company's decade-long under recovery of NPC in Oregon.

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[7] PAC/500, Dickman/46-53; PAC/901 at 23.
[8] TR. 64-65, 72-73 (Ordonez); PAC/909 at 45.
[9] TR. 50-51 (Mullins).

II. ARGUMENT

A. The Commission Should Approve PacifiCorp's System Balancing Proposal to Increase the Accuracy of the NPC Forecast.

PacifiCorp's system balancing proposal improves the forecast of the costs of balancing the Company's system in short-term markets. PacifiCorp's historical data demonstrates that it incurs system balancing costs that are not reflected in the Company's forward price curve or modeled in GRID. PacifiCorp's Oregon rates have systemically under forecast NPC by 5 to 10 percent,[10] partly based on a systematic understatement of actual system balancing costs.[11]

In this case, the Company used a rolling three-year average of historical data to refine its hourly forward price curve and to model additional system balancing volumes.[12] The Company's proposal responds to the Commission's direction "to refine its modeling to produce the best possible estimates of all components of net power costs"[13] and to address systematic biases in the treatment of system balancing transactions.[14]

1. PacifiCorp's Proposed Forward Price Curve Properly Recognizes the Price Differences Between System Balancing Purchases and Sales.

Under its system balancing proposal, PacifiCorp's forward price curve now has separate prices for forecasted system balancing sales and purchases, derived from the Company's actual experience. In the past, the Company determined the market price inputs

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[10] PAC/100, Dickman/22 (Company under-recovered NPC since at least 2007); PAC/200, Graves/2-3. The Company's change to its forward price curve to reflect the price differences between the Company's purchases and sales increased NPC by $4.3 million. The Company's additional transaction volume to account for the use of standard block purchasing increased NPC by $3.7 million. PAC/500, Dickman/17.

[11] PAC/200, Graves/2-3.

[12] PAC/100, Dickman/26.

[13] Order No. 12-409 at 7.

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

for GRID by applying hourly scalars to the Company's monthly forward price curve, with no differentiation based on whether the transaction modeled in GRID is a purchase or a sale.[15]

The Company's undisputed evidence demonstrates that historical prices for system balancing purchases are greater than historical prices for system balancing sales.[16] This is the result of timing differences between when the Company is a seller and when the Company is a purchaser in day-ahead and hourly markets.[17] Additionally, the average historical purchase and sales prices differ substantially from the historical average monthly price. For example, in September 2013, the average market price was $38 per megawatt-hour (MWh), while the Company's average purchase price was $43/MWh and the average sales price was $29/MWh.[18] To account for this differential, the Company's proposal calculates separate prices for purchases and sales beginning with the hourly forward price and then scaling that price based on the Company's actual historical purchases and sales compared to the actual historical monthly average market prices.[19]

The Commission has previously recognized that system balancing purchase and sale prices will not be equal because of timing differences. In docket UE 167, Staff recommended that Idaho Power use a flat forward price curve with a single average monthly price for both purchases and sales.[20] Idaho Power presented historical data and analysis demonstrating that its purchases were typically at on-peak prices, while its sales were

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[15] PAC/100, Dickman/23.
[16] *See e.g.* PAC/500, Dickman/16; PAC/600, Graves/6, 8.
[17] 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.
[18] PAC/500, Dickman/16.
[19] PAC/500, Dickman/14; PAC/507, Dickman/1.
[20] *Re Idaho Power Co. Request for General Rate Revision*, Docket No. UE 167, Order No. 05-871 at 8 (July 28, 2005); *Re Idaho Power Co. Request for General Rate Revision*, Docket No. UE 167, Idaho Power/300, Peseau/17-19. The Company requests that the Commission take official notice of the Idaho Power testimony pursuant to OAR 860-001-0460(1)(d).

typically at off-peak prices. CUB agreed that Idaho Power's purchases should use on-peak prices and its sales should use off-peak prices.[21] The Commission found "merit in Idaho Power's argument that its power purchases and sales should not be subject to flat prices" and therefore the Commission directed Idaho Power to use a forward price curve with separate prices for purchases and sales—"on-peak prices for purchases and off-peak prices for sales."[22] The Company's proposal here is fundamentally the same adjustment that the Commission approved for Idaho Power in 2005, which Idaho Power continues to use today.

CUB now attempts to distinguish its support for Idaho Power's separate purchase and sale pricing, arguing that Idaho Power did not refine its forward price curve based on historical market data.[23] But the underlying principle recognized by the Commission in Order No. 05-871 is that purchases and sales occur at different times and at different prices and that this systematic differential should be accounted for in forward prices. The Company's proposal reflects this principle.

CUB also implies that using historical data to refine a forecast violates normalization because in Order No. 05-871, the Commission stated that rates are set on a normalized basis.[24] But the Commission's observation was made in response to Idaho Power's request that the Commission set rates using the "specific and immediate hydro conditions" and had nothing to do with the development of a forward price curve based on historical differences between purchase and sale prices.[25] On the contrary, as described in more detail below, the

[21] Order No. 05-871 at 7.
[22] *Id.* at 8.
[23] CUB's Prehearing Memorandum at 5.
[24] *Id.*
[25] Order No. 05-871 at 7.

Commission regularly relies on historical data to develop NPC forecast inputs and doing so does not violate normalization.

The Commission has also approved a higher price for market purchases for Portland General Electric Company (PGE) through the modeling of a super-peak contract with a purchase price greater than the forecast on-peak Mid-Columbia (Mid-C) prices.[26] PGE's modeling is functionally equivalent to the Idaho Power adjustment and the Company's proposal here in that it recognizes that purchases do not always correspond to the monthly average forward price.

The Commission is not alone in recognizing a differential between short-term purchase and sale prices. The California Public Utilities Commission (CPUC) rejected an argument that a utility was imprudent because its hour-ahead sales prices were significantly lower than its hour-ahead purchase prices.[27] The CPUC found that simply comparing purchase and sale prices was unreasonable because:

> ...such a comparison inappropriately assumes that hour-ahead sales and purchases are comparable. These transactions are not comparable because they are impacted by demand, availability of product types, delivery points, volatility of minute-to-minute changes in natural gas prices, transmission conditions, and load or resource balances.[28]

ICNU contends that the Company does not incur any system balancing costs based on the assumption that purchases and sales will be perfectly offsetting—*i.e.*, every purchase made at a price greater than the monthly average price will be perfectly offset by a sale that is equal in volume and price.[29] ICNU acknowledged in discovery that its argument was based

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[26] PAC/500, Dickman/36.
[27] *Re Southern Calif. Edison Co.*, 2006 WL 151905 at * 2 (C.P.U.C. 2006).
[28] *Id.*
[29] ICNU/100, Mullins/10.

on nothing more than its witness' unsupported opinion.[30] The Company conclusively demonstrated ICNU's theory did not correlate to the Company's actual experience, and neither Staff nor CUB dispute that purchase and sales prices are divergent. ICNU never challenged the Company's historical calculations and ICNU even concedes that it is "expected" that average purchase and sale prices over the course of a month will differ from the overall monthly average price due to timing differences between purchases and sales.[31]

Moreover, as explained by PacifiCorp's expert witness, Frank Graves of the Brattle Group, ICNU's position is analytically flawed.[32] Mr. Graves explained the positive correlation between forecasting errors that require balancing and prices—meaning that when the Company is required to purchase additional volumes to balance its system, it does so when prices are higher than expected due to increased demand.[33] As PacifiCorp's data verifies, the Company tends to purchase volumes when regional demand (and therefore price) is high and it tends to sell power when regional demand (and therefore price) is low.[34] ICNU's argument that purchases and sales will be offsetting incorrectly assumes that there is no correlation between demand and prices.[35] Mr. Graves confirmed that it is reasonable for PacifiCorp to incur systemic balancing costs in the day-ahead and hourly markets.

ICNU also argues that the Commission has a "long-standing policy of rejecting adjustments designed to impute an extrinsic or marginal value on balancing transactions."[36] ICNU's only support for this sweeping generalization is Order No. 07-446, where the

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30 PAC/600, Grave/4-5 (quoting ICNU response to PacifiCorp's Data Request No. 4).
31 ICNU/100, Mullins/16.
32 PAC/600, Graves/6.
33 PAC/600, Graves/8.
34 PAC/600, Graves/6.
35 PAC/600, Graves/9.
36 ICNU Prehearing Memorandum at 3.

Commission rejected a revenue imputation after finding that there was no evidence of net margin on system balancing transactions.[37] ICNU's argument omits the Commission's specific direction in Order No. 07-446 for the parties to examine GRID to determine if there is a "systematic bias in the way it treats short-term wholesale energy transactions, both for system balancing and for arbitrage and trading."[38] Moreover, Staff's margin adjustment at issue in Order No. 07-446 imputed system balancing revenue based on a historical true-up of actual to forecast balancing transactions. This is fundamentally different than the Company's proposal here to a use rolling, multi-year average to forecast the difference between average monthly prices and actual prices in the short-term and real-time markets.

2. Commission Precedent Supports the Use of Historical Data to Forecast System Balancing Costs.

Both aspects of the Company's system balancing proposal rely on historical transactional data. First, the Company's refined forward price curve uses the historical differential between purchase and sale prices and the average monthly price to create a more accurate hourly price forecast.[39] Second, the Company's volume adjustment uses actual historical transactions to determine the test year cost of balancing transactions volumes that were not modeled in GRID.[40]

ICNU argues that the Company's pricing adjustment improperly relies on historical data that includes prices influenced by anomalous weather conditions.[41] CUB similarly claims that the Company's pricing adjustment improperly attempts to forecast the actual

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[37] Order No. 07-446 at 10-11 ("The record shows that 87 percent of Pacific Power's short-term transactions are for balancing. Pacific Power buys or sells energy to balance load and supply. At any time, Pacific Power may be a net buyer or seller of energy to balance its system. There is no evidence of a systematic tendency toward either role, or of any net margin on such transactions.").

[38] *Id.*

[39] PAC/500, Dickman/14.

[40] PAC/500, Dickman/15.

[41] ICNU Prehearing Memorandum at 5.

expected forward prices rather than weather normalized forward prices.[42] Contrary to ICNU's and CUB's arguments, the Company's proposal here fully comports with the Commission's approach to setting normalized NPC.[43] As outlined below, the Commission has frequently relied on historical averages to forecast NPC and all the parties to this case have at some point supported the use of historical data in discrete NPC adjustments.[44]

- In the 2008 TAM, the Commission adopted Staff's proposed adjustment to reflect the margin earned by the Company from its arbitrage and trading activity.[45] Staff argued that this margin was not accounted for in GRID and calculated its credit using three years of historical data.[46] In subsequent TAMs, Staff, ICNU, and CUB all supported this credit without concern that it used historical data or was inconsistent with normalized ratemaking.[47]
- In the 2012 TAM, the Commission approved the Company's proposal to improve the accuracy of the NPC forecast by using hourly scalars derived from historical data. The Commission found 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

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[42] CUB's Prehearing Memorandum at 4.

[43] *See, e.g.* Order No. 07-446 (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. 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).

[44] ICNU has also proposed adjustments in prior PacifiCorp cases outside of Oregon that used four years of historical data to forecast an arbitrage sales margin and recommended modeling power sales contracts using historical delivery patterns. *Wash. Utils. & Transp. Comm'n v. PacifiCorp*, Docket UE-100749, Order 06 at 42-43, 49-52 (Mar. 25, 2011).

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

[46] *Id.* at 9.

[47] Order No. 12-409 at 8-9.

consistent with historical price data."[48] Both Staff and CUB supported the Company's proposed scalars and ICNU did not object to the calculation of the scalars using historical data. Indeed, in that same case, ICNU argued that the Company should use purely historical forward price curves when a particular market hub lacks a publicly available forward curve.[49]

- In the 2013 TAM, the Commission affirmed the use of market caps to model market liquidity.[50] The market caps approved by the Commission included a modification recommended by Staff and ICNU. Rather than use the historical average transaction volumes, the modified caps used the highest historical monthly transaction level at each market hub modeled in GRID. No party in that case argued that the market caps violated normalization because they relied on historical data.
- In the 2014 TAM, the Commission reaffirmed the use of historical averages for forecasting when it approved the Company's proposal to shape hourly wind profiles based on historical data, stating: "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."[51]

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[48] *Re PacifiCorp 2012 Transition Adjustment Mechanism*, Docket No. UE 227, Order No. 11-435 at 18-20 (Nov. 4, 2011).
[49] *Id.* at 16.
[50] Order No. 12-409 at 7-8.
[51] *Re PacifiCorp 2014 Transition Adjustment Mechanism*, Docket No. UE 264, Order No. 13-387 at 2-4 (Oct. 28, 2013).

The Company's system balancing proposal is entirely consistent with this precedent and improves the accuracy of the GRID model.[52] ICNU's and CUB's criticisms lack credibility given the Commission's use of historical data to forecast market transactions and their own past support for such an approach. Moreover, CUB's contention that the TAM is "not expected to accurately account for actual costs"[53] cannot be reconciled with the Commission's direction that the TAM be refined to accurately forecast actual power costs.[54]

3. ICNU's Similar Adjustment for Short-Term Transactions in PGE's Current NPC Filing Undermines its Criticism of the Company's Proposal.

Of all the parties, ICNU raised the most objections to the Company's system balancing proposal. But ICNU's criticism is undermined by its own adjustment to use historical market prices to forecast future system balancing margins in PGE's current NPC filing. ICNU's PGE adjustment is intended to capture the alleged margins PGE earns at the California-Oregon Border (COB) by comparing the historical transaction price at COB to the actual hourly Mid-C market price.[55] ICNU's PGE adjustment is conceptually and mechanically identical to the Company's proposal in this case.

First, in this case, ICNU argues that the Company's adjustment is improper because it is made outside GRID and other Northwest utilities do not track system balancing transactions and costs outside of their NPC models.[56] But ICNU's PGE proposal is a system balancing adjustment made outside PGE's power cost model. ICNU's PGE adjustment relates to transactions made to "balance the Company's overall load and resource position"

[52] 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.

[53] CUB/100, Jenks-Hanhan/5-6 and *see also* Prehearing Memorandum of CUB of Oregon 4-5.

[54] Order No. 12-409 at 7.

[55] PAC/905 at 2.

[56] ICNU/100, Mullins/9.

through market purchases and sales.[57] Mr. Mullins specifically justifies his PGE adjustment, "[b]ecause the MONET model does not account for transactions at the COB market . . ."[58] Moreover, both adjustments are based on spot market transactions and rely on hourly pricing data for their calculation.[59]

Second, ICNU argues in this case that it is improper for PacifiCorp to use three years of historical data for its adjustment, particularly because the Company's historical data set includes "anomalous" data from February 2014.[60] But ICNU's PGE adjustment also relies on three years of historical market data that includes the exact same "anomalous" data from February 2014.[61]

Third, in this case, ICNU claims that the Company used historical market data to forecast future system balancing costs, which is improper because historical prices have no bearing on future prices.[62] ICNU's PGE adjustment is explicitly premised on Mr. Mullins' claim that the historical market spreads between Mid-C and COB will be representative of future market spreads and indicative of the future system balancing margin PGE will earn.[63]

Fourth, ICNU claims that the Company's historical NPC under-forecasting is no basis to conclude that it is incurring system balancing costs that are not captured in its forecast.[64] ICNU made the exact opposite claim in PGE's case, where ICNU justified its proposal because PGE had exhibited a "pattern of over-forecasting" its NPC and ICNU reasoned that

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[57] PAC/905 at 2.
[58] PAC/905 at 9.
[59] PAC/905 at 7 (calculates margins using the "actual hourly Mid-C market price to determine the economic margin actually earned on each COB transaction.").
[60] ICNU/100, Mullins/18; ICNU/200, Mullins/7; ICNU/200, Mullins/11.
[61] PAC/905 at 7. The specific data that ICNU claims is anomalous is Mid-C prices from February 2014, which ICNU then used to quantify its PGE adjustment.
[62] ICNU/100, Mullins/15-16.
[63] PAC/905 at 8-9.
[64] ICNU/200, Mullins/7-11.

the failure of MONET to capture PGE's system balancing margins contributed to this pattern.[65] Importantly, the "pattern of over-forecasting" identified by ICNU consisted of PGE over-forecasting its NPC in three of the last four years.[66] Given that PacifiCorp has under-recovered its NPC in Oregon for at least a decade, ICNU's reasoning in the PGE case supports the Company's proposal in this case.[67]

4. ICNU Falsely Characterizes the Company's Proposal as a Bid-Ask Spread.

ICNU primarily criticizes the Company's refined forward price curve as an excessive bid-ask spread.[68] But this argument and ICNU's related proposal to eliminate market caps are fundamentally flawed because PacifiCorp has not modeled a bid-ask spread in its proposal.

A bid-ask spread measures the difference in price at any point in time between buying and selling the same security concurrently.[69] ICNU is the only party that claims the Company's differentiated purchase and sale prices in its forward price curve represent a bid-ask spread. But ICNU's witness reaches this conclusion only after testifying that the Company's proposal makes no sense as a bid-ask spread, was not calculated correctly as a bid-ask spread, and the results bear no resemblance to a bid-ask spread.[70] ICNU's own testimony persuasively undermines its conclusion that the Company was modeling a bid-ask spread and effectively refutes all of ICNU's critiques based on this conclusion.

Instead of modeling a bid-ask spread, the Company's proposal measures the difference between the actual prices for hourly and daily market transactions and the

[65] PAC/905 at 9.
[66] PAC/905 at 8.
[67] PAC/100, Dickman/22.
[68] ICNU's Prehearing Memorandum at 5-6.
[69] *Id.* at 6; *see also* PAC/600, Graves/10.
[70] ICNU/100, Mullins/16-18.

historical monthly market prices.[71] This accounts for the variances that tend to arise when the Company sells unplanned excess power into the spot market, or purchases supplemental power, for different volumes and under new expectations of market prices than prevailed previously.[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.[74]

Despite this concession and PacifiCorp's testimony explaining bid-ask spreads, ICNU continues to insist the Company's proposal is a bid-ask spread and repeats the definition of a bid-ask spread to make its point.[75] As explained by Mr. Graves, the sale of unplanned excess power and the purchase of needed supplemental power will not be concurrent transactions and will not be subject to the same market conditions.[76] Therefore, the Company's proposal does not reflect a bid-ask spread.

For the reasons stated above, ICNU's alternative proposal to replace PacifiCorp's adjustment with a $0.50/MWh spread lacks any theoretical foundation.[77] In addition, ICNU has presented no analysis supporting the reasonableness its proposed bid-ask spread, which it derived from an appendix to PacifiCorp's 2008 wind integration study.[78] ICNU concedes that there is generally little empirical data to calculate a bid-ask spread for any particular

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[71] PAC/600, Graves/10-11.
[72] PAC/600, Graves/10-11.
[73] ICNU/100, Mullins/16.
[74] PAC/500, Dickman/32-34.
[75] ICNU's Prehearing Memorandum at 6.
[76] PAC/600, Graves/10-11.
[77] ICNU's Prehearing Memorandum at 6-7.
[78] ICNU/100, Mullins/17.

market.[79] Yet ICNU contends that the bid-ask spread in 2016 for all six of PacifiCorp's markets will be equal to $0.50/MWh—without any analysis whatsoever.

ICNU also argues that if PacifiCorp's proposal or ICNU's $0.50/MWh spread is adopted, the Commission should eliminate the Company's market cap adjustment.[80] ICNU reasons that market caps already model market liquidity, so if the Commission adopts a bid-ask spread, which is also used to model market liquidity, market caps must be eliminated to avoid double counting the market liquidity impact in the GRID model. The most basic problem with this reasoning is that PacifiCorp did not model a bid-ask spread, [81] so there is no possibility that the GRID model would double count market liquidity restraints if PacifiCorp's proposal was approved.[82]

PacifiCorp's proposal to more accurately capture the costs of its system balancing transactions does not provide a replacement to market caps.[83] In 2013, the Commission decided that some form of market caps are required to produce a reasonable forecast.[84] ICNU has not provided a reason, other than its faulty bid-ask spread argument, for the Commission to reconsider this fully-ligated issue [85] Removal of market caps would decrease the modeled costs of PacifiCorp's system balancing transactions by imputing unrealistic sales volumes in illiquid markets.[86]

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[79] ICNU/100, Mullins/18.
[80] ICNU/100, Mullins/19; *see also* ICNU's Prehearing Memorandum at 6-7. Removal of market caps from the Company's proposal reduces NPC by approximately $1.69 million. ICNU's adjustment for removal of market caps and the $0.50/MWh bid-ask spread reduces NPC by $9.4 million. PAC/500, Dickman/19
[81] PAC/500, Dickman/32; PAC/600, Graves/10-11.
[82] PAC/500, Dickman/40-42. *See also* ICNU's Prehearing Memorandum at 6.
[83] PAC/500, Dickman/39.
[84] Order No. 12-409 at 7.
[85] PAC/500, Dickman/39.
[86] PAC/500, Dickman/39-40.

In particular, ICNU's recommendation to remove market caps from the Company's proposal would artificially inflate the Company's sales volume by 10 percent, which is approximately seven percent over historical levels (including bookouts).[87] The elimination of market caps plus ICNU's $0.50/MWh bid-ask spread proposal would increase sales volume by an additional 18 percent.[88] 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.[89]

5. PacifiCorp's Proposal Accurately Reflects the Historical Level of Sales and Purchases.

ICNU claims that PacifiCorp's current position is inconsistent with its position in docket UE 245 and that the Company overstates the level of sales and purchases in this case.[90] ICNU's argument focuses on the treatment of bookouts, which are transactions that are equal and offsetting in terms of volume, delivery period, and location.[91] Both here and in docket UE 245, however, the Company made the same argument—comparisons between transaction levels in actual and forecast NPC must include or exclude bookout transactions on both sides to avoid apples-to-oranges comparisons.[92] Here, the Company demonstrated that its modeled volumes, including the additional system balancing transactions that are proxies for bookouts, correspond to historical transaction volumes including bookouts.[93]

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[87] PAC/500, Dickman/40.
[88] PAC/500, Dickman/41.
[89] *See e.g.* Order No. 12-409 at 7.
[90] ICNU's Prehearing Memorandum at 4-5.
[91] PAC/500, Dickman/25-27.
[92] PAC/500, Dickman/28.
[93] PAC/500, Dickman/27.

ICNU's argument that the Company overstates transaction volumes is solely a function of ICNU omitting bookout transaction volumes from historical levels.[94]

In docket UE 245, ICNU and CUB argued that all transactions, even bookouts, must be accounted for when modeling NPC transaction levels.[95] The Company's proposal here does just that by including additional system balancing transactions, *i.e.*, proxies for bookouts, that are systematically incurring costs.

6. ICNU's Additional Arguments Offer No Basis for Denying PacifiCorp's Proposal.

ICNU offers several additional criticisms of the Company's proposal. First, in cross-answering testimony, ICNU argued that the Company's system balancing adjustment is unnecessary because GRID accurately forecasts NPC.[96] ICNU discounts the Company's claims of under-forecasting, arguing that the only way to demonstrate that the GRID model is flawed is through a backcast analysis, which the Company has not performed.

At hearing, PacifiCorp's witness explained that the Company's modeling refinement here is not premised on a flaw in GRID.[97] Rather, the Company's proposal refines the forward price curve that is a GRID input. As ICNU concedes, the accuracy of forecast inputs determines the Company's NPC variances, not the model itself.[98] Thus, PacifiCorp has proposed to improve the inputs and outputs of the GRID model to better reflect reality.

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[94] PAC/500, Dickman/28.

[95] *Re PacifiCorp's 2013 Transition Adjustment Mechanism*, Docket No. UE 245, Joint ICNU-CUB Posthearing Brief at 11-12 (Sept. 14, 2012) ("There is no reason why power sales transactions that are settled financially as a scheduling convenience should not be fully accounted for when estimating the Company's net power costs."). The Company requests that the Commission take official notice of this brief pursuant to OAR 860-001-0460(1)(d).

[96] ICNU/200, Mullins/8.

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

[98] ICNU/200, Mullins/8.

GRID is an accurate model, but there are practical limitations in any power system forecasting model.[99]

Second, ICNU incorrectly claims 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.[100] 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.[101] 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.[102] The Company's adjustment does not determine the quantity or cost of forward hedging transactions during the test period.[103]

Third, ICNU argues that the Company is already recovering system balancing costs through its inter-hour wind integration costs. But the inter-hour integration cost studies use the same hourly price forecast now used in GRID, which is uniform across each month.[104] 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.

Fourth, ICNU argues the Company does not incur any system balancing costs because system balancing consists of nothing more than the Company making spot market

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[99] PAC/200, Graves/4-7.
[100] ICNU/100, Mullins/11-12.
[101] 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.
[102] PAC/600, Graves/9-10.
[103] PAC/500, Dickman/30-31.
[104] PAC/500, Dickman/37-39.

purchases to close forward positions.[105] ICNU claims that there is no bias between forward and spot prices and therefore PacifiCorp will incur no additional cost when it transacts on the spot market to balance its system.[106] Thus, ICNU claims that the Company's system balancing proposal is really trying to recover a risk premium implied in forward prices.

ICNU's reasoning fails because system balancing transactions are not simply the Company closing forward positions in the spot market. As explained by Mr. Graves, balancing costs are distinct from the costs arising from the difference between forward and realized spot prices.[107] Balancing occurs when system conditions change in many ways (*e.g.*, changes in loads or changes in resource dispatch), not simply because spot prices differ from forward prices.[108] Moreover, spot market prices are affected by the same changing market conditions that cause PacifiCorp to engage in system balancing transactions. ICNU's conflation of system balancing with closing forward positions is analytically incorrect, as is ICNU's conclusion that the Company's proposal seeks recovery of a risk premium associated with spot transactions.

7. The Commission Should not Delay Approval of the Company's Proposal.

Staff recommends that the Commission delay implementing the proposal, despite agreeing with the Company's rationale for both price and volume components of the proposal.[109] Staff recommends that the Commission open a generic investigation to examine a multitude of issues related to wholesale market activity, most of which have little to do

[105] ICNU/100, Mullins/9-10.
[106] ICNU/100, Mullins/9-10.
[107] PAC/600, Graves/5-6.
[108] PAC/600, Graves/5-6.
[109] Staff/100, Ordonez/19.

with the merits of the Company's system balancing proposal, such as hedging strategies, market liquidity, and arbitrage pricing theory.[110]

Additional delay is unwarranted. The Commission now has a fully developed record in this case, including unchallenged evidence that: (1) the Company is systematically incurring substantial system balancing costs; and (2) these costs will remain uncovered in NPC absent adoption of the Company's proposal.

In the 2014 TAM, Staff and CUB also asked for more time for additional workshops and review of the Company's proposal for hourly wind shaping.[111] The Commission correctly found that the benefits of the improved model outweighed concerns about complexity and refused to delay approval. The fact that the Company's proposal in this case is supported by extensive historical data and analysis supports approval of the proposal, not delay or initiation of a generic investigation to examine unrelated issues.[112]

B. ICNU's Regulating Reserve Adjustment Applies the Wrong Standard and Jeopardizes System Reliability.

1. The Company's Reserve Modeling Reasonably Balances the Costs of Holding Reserves with the Need for System Reliability.

The Company is required to carry additional generating capacity in reserve so that it has adequate capacity at all times to adjust to fluctuations in generation and load and maintain system frequency.[113] The Company's reserves ensure that it is able to provide safe and reliable service to customers and help maintain the reliability of the electricity grid.

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[110] Staff/200, Ordonez/13-14.
[111] Order No. 13-387 at 3-4.
[112] PAC/500, Dickman/20-22.
[113] PAC/901 at 11.

As described in the Company's wind integration studies, the Company must hold two types of reserves—contingency reserves and regulating margin.[114] Regulating margin is also referred to as "flexibility reserves" in the Company's Energy and Environmental Economics, Inc. (E3) study.[115] Regulating margin is the additional capacity that the Company holds to ensure it has adequate reserves at all times to meet NERC's reliability standards for system operation.[116] ICNU has proposed a drastic reduction to the Company's regulating margin in this case.

The Company's wind integration studies determine the level of regulating margin necessary to ensure system reliability and comply with applicable reliability standards. The Company uses the regulating margin calculated in the wind integration studies in actual operations.[117] In 2010, the applicable reliability standard changed from the CPS2 standard to the BAAL standard. The BAAL standard requires the Company to maintain or correct 100 percent of all frequency deviations that may occur on its system.[118]

Using the BAAL standard, PacifiCorp's 2012 and 2014 wind integration studies documented the need for reserve levels using a 99.7 percent confidence interval to ensure that the Company can respond to as many reliability deviations as possible, maintain reliable service to customers, and support the integrity of the regional grid.[119] The Company's confidence interval is the same or similar to what BPA and BC Hydro derived from their

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[114] PAC/901 at 11.
[115] PAC/909 at 17.
[116] PAC/902 at 9.
[117] PAC/902 at 24.
[118] PAC/902 at 24 ("In operations, scheduling system resources to meet regulating margin requirements ensures that PacifiCorp can meet the BAAL reliability standard. This standard is tied to real-time system frequency, and as this frequency fluctuates, real-time operators use regulating margin reserves to maintain or correct frequency deviations within the allowed 30-minute period, 100% of the time.").
[119] PAC/901 at 23.

reserve studies under the BAAL standard.[120] The Technical Review Committee (TRC) that evaluated the Company's 2014 wind integration study concluded that the study, including the use of a 99.7 percent confidence interval, was reasonable and the findings and conclusions were sound.[121]

2. ICNU's Adjustment Results in Reserves that Fail to Satisfy NERC's Standards.

Relying only on an analysis of the Company's CPS2 scores (which the Company continues to report for informational purposes only),[122] ICNU argues that the Company should reduce its regulating margin by 44 percent so that the Company operates at a much lower reliability metric.[123] Although ICNU admits that the CPS2 standard has not applied to the Company since 2010 and will not apply in the test year in this case, ICNU argues that the Company's reserves should be calculated using this outdated and inapplicable standard.[124] ICNU also proposes using a 90 percent confidence interval under the CPS2 standard, even though the Company has historically used a 97 percent confidence interval under the CPS2 standard.[125]

To support its recommendation, ICNU contends that the Company's wind integration studies continue to rely on the CPS2 standard.[126] ICNU's claim is clearly refuted by the

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[120] PAC/901 at 23.
[121] PAC/902 at 37-38.
[122] ICNU/100, Mullins/25.
[123] ICNU/100, Mullins/28; PAC/500, Dickman/46-47 (ICNU recommends reserve decrease of 245 MW); PAC/500, Dickman/67 (Company modeled 560 MW of regulating margin).
[124] ICNU/100, Mullins/28 (90 percent confidence interval consistent with lower bound of CPS2 standard and recommendation intended to "move the Company toward its actual CPS2 performance."); ICNU Prehearing Memorandum at 8; TR. 14-15 (Mullins).
[125] ICNU/100, Mullins/24 (describing the use of a 97 percent confidence interval in 2010 wind integration study, which was based on CPS2 standard).
[126] ICNU/100, Mullins/23; TR. 18 (Mullins).

studies themselves. For example, the 2012 wind integration study explains that the new BAAL standard:

> ...modified reserves planning from considering CPS2 to an avoidance of using contingency reserve for anything other than specified contingency events, as that is not allowed. Therefore, the regulating margin requirement evaluated in each time interval of the Wind Integration Study is intended to cover all anticipated uncertainties in short term load and wind behavior, consistent with the requirement of the Company to meet its firm load obligations and not deploy contingency reserve to cover what it should manage with regulating margin.[127]

Both studies completed after the imposition of the BAAL standard used the same 99.7 percent confidence interval—making clear that the Company was no longer relying on the CPS2 standard that had previously supported a 97 percent confidence interval.[128]

At hearing, ICNU argued that the Company could hold fewer reserves because both Idaho Power and the E3 studies rely on lower confidence intervals of 90 percent and 95 percent, respectively.[129] But both Idaho Power and the E3 studies were modeling reserves using a CPS2 standard, which is not applicable to the Company.[130]

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[127] PAC/901 at 44; *see also* PAC/901 at 11-12 ("Since the Company's 2010 Wind Integration Study, the performance standards have evolved from a calculated Control Performance Standard 2 (CPS2) mandated by NERC BAL-001-0 11 to a more dynamic regime mandated by NERC BAL-007-1, called Balancing Authority ACE Limit (BAAL), in which the Company's performance standard can be affected by the frequency of the interconnection."); PAC/901 at 44 ("In the past, the Company managed its balancing areas to a target called [CPS2], which specified a limited number of excursions from a net system interchange target. Since March 1, 2010, [] PacifiCorp has been participating in a regional field test of the Reliability Based Control standard, which replaces the system interchange requirements with a regional frequency-based requirement."); PAC/902 at 9.

[128] PAC/901 at 23; PAC/902 at 19.

[129] TR. 21 (Mullins).

[130] PAC/909 at 46 ("E3 chose to model a CPS2 compliance target which requires BAAs to secure load following reserves to meet 97% of forecasted load following demand . . ."); PAC/906 at 29; PAC/907 at 33; *Idaho Power Company's Wind Integration Study Report* at 39 (explaining that the study did not account for the BAAL standard, but that "while RBC may allow balancing reserves-carrying generators to not respond to changes in load or wind in real-time operations, the scheduling of these generators must still include appropriate amounts of balancing reserves because it is not known at the time of scheduling to what extent an imbalance between generation and load will be permitted."). The Company requests that the Commission take official notice of the Idaho Power study pursuant to OAR 860-001-0460(1)(d). The study was filed with the

ICNU also argues that the BAAL standard requires fewer reserves because it allows the Company to correct deviations within 30 minutes, rather than the 10 minute correction window required by CPS2.[131] This argument oversimplifies the Company's obligation under the new standard. Under the CPS2 standard, the Company was required to maintain 90 percent compliance.[132] Because the new BAAL standard requires 100 percent compliance, however, the longer window under BAAL for restoring system balance does not lower the Company's reserve obligation.[133]

Mr. Mullins' previous testimony undermines ICNU's recommendation here. In the Company's 2014 Washington rate case, Mr. Mullins recommended a reduction in the Company's regulating reserves based on the same 2012 wind integration study that he now faults for calculating excessive reserves.[134] At hearing, Mr. Mullins admitted that he never expressed any concern over how 2012 study calculated reserves when he previously relied on that study in Washington.[135]

Staff's analysis in this case further undermines ICNU's recommendation. ICNU testified that Staff's proposal regarding EIM within-hour dispatch benefits "largely overlaps" with ICNU's CPS2 adjustment.[136] But in cross-answering testimony, Staff withdrew its

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Commission as part of Idaho Power's 2011 Integrated Resource Plan Update, which was filed in Docket No. LC 53 on February 14, 2013.

[131] ICNU Prehearing Memorandum at 8.

[132] PAC/500, Dickman/47.

[133] PAC/500, Dickman/49; PAC/902 at 24 ("In operations, scheduling system resources to meet regulating margin requirements ensures that PacifiCorp can been the BAAL reliability standard. This standard is tied to real-time system frequency, and as this frequency fluctuates, real-time operators use regulating margin reserves to maintain or correct frequency deviations within the allowed 30-minute period, 100% of the time.").

[134] PAC/903 at 12-13; TR. 23 (Mullins). The Washington commission rejected Mr. Mullins' adjustment. TR. 43-44 (Mullins).

[135] TR. 23 (Mullins).

[136] ICNU/200, Mullins/5.

adjustment after concluding that the EIM does not allow the reserve benefit Staff assumed.[137] Staff specifically recommended rejecting ICNU's adjustment because "the historical CPS2 values are not relevant for establishing compliance with reliability standards."[138]

C. The Company has Reasonably Modeled EIM Benefits and Further Adjustments are Unwarranted.

The Company has reasonably accounted for EIM benefits in 2016. The Company will model EIM inter-regional dispatch benefits using ten months of actual historical data to account for the seasonal changes in benefits.[139] The Company included additional EIM inter-regional dispatch and flexibility reserve benefits resulting from the participation of NV Energy, Arizona Public Service (APS), and Puget Sound Energy (PSE) in the EIM in 2016.[140] In total, the Company's filing reflects benefits of $12.4 million, or approximately $3 million on an Oregon-allocated basis, resulting from its participation in the EIM.[141] The $12.4 million in EIM benefits in the filing are in addition to the optimized dispatch of the Company's generation within its balancing authority areas (BAAs) (*i.e.*, intra-regional dispatch), which can now be achieved in actual operation and which has always been reflected in the GRID model.[142]

1. ICNU's Flexibility Reserve Adjustment based on Increased Dynamic Transfer Capability has no Basis in Fact.

ICNU contends that the Company's increased dynamic transfer capability resulting from the Idaho Power asset exchange, coupled with its ability to engage in sub-hourly transfers under the EIM, will allow the Company to transfer flexibility reserves between its

[137] Staff/200, Ordonez/2.
[138] Staff/200, Ordonez/20.
[139] PAC/500, Dickman/61-62. The Company will use actual EIM data through September 2015 in the final update.
[140] PAC/500, Dickman/12-13.
[141] PAC/500, Dickman/12-13.
[142] PAC/100, Dickman/11; Staff/100, Ordonez/14-15.

east and west BAAs.[143] Based on this premise, ICNU recommends an adjustment that assumes 50 MW of flexibility reserves are transferred between BAAs, lowering the Company's overall reserve requirement.[144]

ICNU's adjustment lacks foundation because the EIM does not allow the Company to transfer flexibility reserves between its BAAs.[145] This fact is made clear in the Company's 2014 wind integration study and in the Company's E3 study.[146]

To bolster its adjustment, ICNU incorrectly relies on similar adjustments proposed by Staff. ICNU originally argued in cross-answering testimony that Staff's reserve adjustment related to the Company's increased dynamic transfer capability was "similar in concept" to this adjustment.[147] But Staff withdrew this adjustment after learning that the Company could not share reserves between its BAAs.[148] At hearing, Mr. Mullins acknowledged that he had not even reviewed the data response that caused Staff to change its position.[149]

Recognizing that Staff concedes that the Company may not share reserves between BAAs, ICNU's prehearing memorandum now claims that Staff's new dynamic transfer adjustment supports ICNU's adjustment.[150] But Staff's new adjustment claims that the dynamic transfer capability increases EIM inter-regional dispatch benefits, not reserve savings.[151] Staff's adjustment and ICNU's adjustment are mutually exclusive to the extent

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[143] ICNU/100, Mullins/31-32.
[144] ICNU/100, Mullins/32-33.
[145] PAC/500, Dickman/54-55.
[146] PAC/902 at 30; PAC/909 at 18.
[147] ICNU/200, Mullins/5.
[148] Staff/200, Ordonez/6-7.
[149] TR. 29-30 (Mullins)
[150] ICNU Prehearing Memorandum at 10.
[151] Staff/200, Ordonez/7.

that they assume different uses for the same dynamic transfer capability. And, as discussed below, Staff's adjustment is premised on demonstrably incorrect assumptions.

ICNU's prehearing memorandum also argues that the Company's admission that it can transfer contingency reserves between BAAs means that the Company can also transfer flexibility reserves.[152] At hearing, however, ICNU's witness conceded that this argument is erroneous because the ability to transfer contingency reserves has no bearing on the ability to transfer flexibility reserves.[153]

Finally, even if ICNU's adjustment was reasonable, it overlaps with the reserve savings ICNU claims under its regulating reserve adjustment. ICNU testified that adopting a lower confidence interval will result in reserve levels that are "more representative" of the EIM benefits that will result from sub-hourly transfers.[154] Because ICNU's BAA flexibility reserve adjustment also purports to model reserve savings resulting from sub-hourly transfers, this adjustment double counts the reserve savings ICNU already claims under its regulating reserve adjustment.[155]

2. Staff's Dynamic Transfer EIM Adjustment Relies on Unsupported and Fundamentally Flawed Assumptions.

Staff's analysis found that the Company's EIM modeling was reasonable, concluding that the Company "made notable and creative efforts to estimate the EIM benefits."[156] Despite this acknowledgement, in cross-answering testimony, Staff presented a new $1.07 million EIM adjustment for benefits associated with the Idaho Power asset exchange. Specifically, Staff claimed that the Company could use the additional 200 MW of dynamic

[152] ICNU Prehearing Memorandum at 10.
[153] TR. 31-32 (Mullins).
[154] ICNU/100, Mullins/27.
[155] PAC/900 at 1 (ICNU's only basis for asserting that flexibility reserves could be transferred is the Company's "ability to effectuate sub-hourly transfers between balancing areas. . .").
[156] Staff/100, Ordonez/12.

transfer capability from the asset exchange to facilitate substantially more EIM exports from the Company's east BAA to the California Independent System Operator (CAISO).[157]

Staff argues the TAM should reflect the claimed benefits of the Idaho Power asset exchange.[158] But the TAM already reflects $0.6 million in benefits related to reduced wheeling expenses, a fact that Staff did not realize in proposing its adjustment.[159] Importantly, the benefits PacifiCorp included in this case are the efficiency savings Staff identified in its public meeting memorandum recommending approval of the asset exchange.[160] That memorandum did not identify benefits resulting from increased dynamic transfer capability or the EIM.

In addition, Staff's adjustment relies on a series of assumptions that Staff did not, and cannot, substantiate. Staff first assumes "that the resources on the margin are located in the PacifiCorp east BAA."[161] Staff then assumes that the Company's dynamic transfer capability "<u>might</u> be critical for transmitting power to the west BAA and then to CAISO" and that the inter-regional EIM benefits "<u>might</u> be dependent on the [dynamic transfer capability] between PacifiCorp's BAA."[162] Staff's reliance on benefits that "might" occur is insufficient to meet "established Oregon ratemaking principles," requiring reasonably known and measurable costs and benefits in the future test year.[163]

Staff's foundational assumption is based on the fact that the average cost of the marginal resources in December 2014 and January 2015 "approximates" the average variable

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[157] Staff/200, Ordonez/8-10.
[158] Staff/100, Ordonez/9.
[159] TR. 64-65 (Ordonez).
[160] *Re PacifiCorp and Idaho Power Co. Request for Approval to Exchange Certain Transmission Assets Associated with the Jim Bridger Generation Plant*, Docket No. UP 315, Order No. 15-184 at App. A at 5 (June 9, 2015).
[161] Staff/200, Ordonez/9.
[162] Staff/200, Ordonez/9 (emphasis added).
[163] *Re Portland Gen. Elec. Co.*, Docket No. UE 115, Order No. 01-777 at 9 (Aug. 31, 2001).

cost of PacifiCorp's coal plants, most of which are in the east BAA.[164] But Staff admitted at hearing that its analysis had not accounted for the greenhouse gas (GHG) adders imposed by the CAISO on imported generation.[165] Staff also admitted that it did not know the magnitude of the GHG adders or how they would impact the comparison that underlies Staff's entire adjustment.[166] In fact, PacifiCorp's E3 study estimated a GHG adder equal to $10.76/MWh.[167] When the GHG adder is added into Staff's comparison, the variable cost of PacifiCorp's coal plants becomes substantially higher than the marginal export resource—undermining Staff's assumption that the Company's coal plants support nearly all of the EIM exports.[168] Without this assumption, there is no basis for Staff's adjustment.

Staff's adjustment also incorrectly assumes that the Company's dynamic transfer capability will be dedicated exclusively to EIM exports to the CAISO. The only basis for this assumption is a Company data response indicating that "in general" the Company's existing 200 MW of dynamic transfer capability in December 2014 and January 2015 was "made available for use within" the EIM.[169] Staff interpreted this response to mean that the Company devoted its entire dynamic transfer capability to EIM exports.[170] But the EIM also allows the Company to more efficiently balance its own system.[171] At hearing, Staff's witness testified that he did not know that the EIM allowed the Company to balance its own system[172] even though his own prefiled testimony recognizes this fact.[173]

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[164] Staff/200, Ordonez/9.
[165] TR. 72-73 (Ordonez).
[166] TR. 72-73 (Ordonez).
[167] PAC/909 at 45.
[168] TR. 71 (Ordonez); Staff/200, Ordonez/9.
[169] Staff/201, Ordonez/4.
[170] TR. 75-78 (Ordonez).
[171] PAC/100, Dickman/10-11.
[172] TR. 75-78 (Ordonez).

3. The Company's Use of Actual Data to Calculate EIM Inter-Regional Dispatch Benefits is Superior to ICNU's Speculative Modeling.

The Company's EIM inter-regional dispatch benefits will vary over the course of a year and may be greatest during the summer months.[174] To capture the seasonal differences in inter-regional benefits in the annual forecast for 2016, the Company proposes to incorporate into its Final Update actual EIM benefit results through September 2015.[175] This ensures that EIM benefits will be based on 10 months of actual data, including all summer months for 2015. Under the Company's proposal, the forecasted benefits 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.[176] In its prehearing memorandum, ICNU incorrectly stated that the Company's proposal would be based on only seven months of actual data.[177] Upon learning of its error at hearing, ICNU's witness acknowledged that the Company's proposal partially addresses its concerns by relying on actual results from 10 months, including all summer months.[178]

In contrast, ICNU calculated the inter-regional dispatch benefits using only two months of actual EIM data extrapolated to a full year based on the price spread between Mid-C and COB markets.[179] ICNU contends that this spread reasonably approximates the export benefits the Company can expect to receive and is therefore a more reasonable

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[173] Staff/100, Ordonez/14 ("The intra-regional dispatch benefits are the benefits of PacifiCorp optimizing its economic dispatch within the Company's BAAs.").
[174] PAC/500, Dickman/61.
[175] PAC/500, Dickman/61-62.
[176] PAC/500, Dickman/61-62.
[177] ICNU Prehearing Memorandum at 11.
[178] TR. 57 (Mullins).
[179] ICNU Prehearing Memorandum at 11.

approximation of expected benefits than actual results.[180] But ICNU's methodology does not correlate to actual EIM experience, where export benefits are negatively correlated to ICNU's price spread.[181] ICNU's proposal is also inconsistent with its EIM adjustment for new participants, which does not rely on market spreads to approximate inter-regional dispatch benefits.[182]

ICNU's prehearing memorandum appears to acknowledge that using actual EIM data is superior, but ICNU still supports its adjustment because Mr. Mullins' adjustment here is smaller than his concurrent adjustment in Wyoming.[183] ICNU cannot support the reasonableness of its proposal by claiming that its witness concocted a larger adjustment in another case.[184]

CUB recognizes that the Company's proposal to use 10 months of actual operational data will improve the accuracy of the forecasted EIM benefits for 2016.[185] Despite this acknowledgment, CUB still recommends that the Commission carve-out EIM inter-regional dispatch benefits from the Company's NPC and require a single-issue deferral of these benefits.[186] CUB's deferral is now unnecessary in light of the Company's proposal to model EIM inter-regional dispatch benefits based on 10 months of actual data. In addition, CUB's recommendation is undermined by its position in other cases where it has steadfastly opposed single-issue NPC deferrals.[187]

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[180] ICNU/100, Mullins/35-36.
[181] PAC/500, Dickman/59-61.
[182] ICNU/100, Mullins/36-39 (ICNU's new participants adjustment does not derive benefits based on market spreads between Mid-C and the market nearest the new participant).
[183] ICNU Prehearing Memorandum at 11.
[184] Notably, the record in this case does not contain a detailed description of Mr. Mullins' Wyoming adjustment or any of the underlying analysis.
[185] CUB's Prehearing Memorandum at 7.
[186] CUB's Prehearing Memorandum at 7.
[187] PAC/500, Dickman/72-73.

4. ICNU Acknowledged that its Inter-Regional Benefits from New EIM Participants are Grossly Overstated.

The Company's reply testimony included inter-regional dispatch benefits resulting from the addition of NV Energy, PSE, and APS to the EIM.[188] For PSE and APS, the Company allocated the new participant inter-regional dispatch benefits identified in each utility's E3 study using the same allocation percentages proposed by ICNU for new participant flexibility reserve benefits.[189] For NV Energy, the Company calculated the inter-regional benefits in the same way that it calculated the benefits for PacifiCorp and the CAISO, but with reduced margins to reflect diminishing returns from incremental transmission capacity.[190]

ICNU developed its own methodology to calculate EIM inter-regional dispatch benefits from new participants. Instead of allocating the benefits identified in the E3 reports, ICNU developed a model that produced benefits so inflated that its witness could not defend them at hearing—even though his testimony originally claimed that his model was "conservative."[191]

For APS, ICNU's methodology resulted in annual benefits to PacifiCorp of $2.9 million.[192] By comparison, APS's E3 study estimated annual benefits to *all* current EIM participants of just $1.4 million.[193] Applying ICNU's allocation factors, results in annual benefits for PacifiCorp of $238,000—less than 10 percent of ICNU's estimate.[194]

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[188] PAC/500, Dickman/62-72.
[189] PAC/500, Dickman/63-64.
[190] PAC/500, Dickman/64.
[191] TR. 51, 53-54 (Mullins).
[192] TR. 53 (Mullins).
[193] TR. 51 (Mullins); PAC/906 at 45.
[194] TR. 53 (Mullins).

The results for PSE are the same. ICNU's methodology results in PacifiCorp benefits that are more than twice the total benefits estimated by E3 and more than ten times greater than PacifiCorp's benefits using ICNU's allocation factors.[195]

One of the reasons that ICNU's methodology produces such unreasonable results is its assumption that increased transmission capacity is directly proportional to increased benefits. Contrary to this assumption, the E3 studies that have examined this issue are clear that there will be diminishing benefits as transmission capacity increases.[196] This logical conclusion is confirmed by PacifiCorp's actual operational experience.[197] The Company's resources that can support additional exports will necessarily be higher cost resources, which reduce both margins and volumes.[198] Margins will decrease because the higher cost resources will be closer in cost to the displaced resource elsewhere in the EIM.[199] Volumes will decrease because the higher cost of PacifiCorp's resource makes it less likely that it will displace a resource elsewhere in the EIM.[200]

ICNU contends that its assumption is not flawed because its assumptions are "patterned after the Company's own transfer volume experience with CAISO."[201] But the Company's actual transfer volume exhibits diminishing returns.[202] Contrary to actual

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[195] TR. 55 (Mullins); PAC/907 at 49.

[196] PAC/500, Dickman/68-70; PAC/909 at 51; PAC/907 at 51 ("The results presented above highlight that the overwhelming majority of potential sub-hourly dispatch benefits are captured with only 300 MW of real- time transfer capability between PSE and PacifiCorp. A threefold increase in this capability only results in a 15% increase in sub-hourly dispatch benefits. This suggests that there are very few intervals throughout the simulation year where it would be economic for PSE to either increase or decrease its generation dispatch and net exchange with other EIM participants by more than 300 MW.").

[197] PAC/500, Dickman/64-69.

[198] PAC/500, Dickman/66-67.

[199] PAC/500, Dickman/66-67.

[200] PAC/500, Dickman/66-67.

[201] ICNU Prehearing Memorandum at 12.

[202] PAC/500, Dickman/68-69.

experience, ICNU's analysis simply assumes that every additional MW of transmission capacity translates directly into an additional MW export.

D. The Company's Refined Unit De-Rate Modeling is Reasonable and Should be Approved in this TAM.

In docket UM 1355, the Commission adopted a new methodology for forecasting thermal plant forced outage rates that included a methodology for de-rating a generating unit's capacity to account for forced outages.[203] The Commission noted, however, that the de-rating methodology it adopted was "outdated and that there are more sophisticated methods of representing forced outages in production cost models."[204] Thus, the Commission encouraged the parties to "explore these modeling alternatives in future rate cases involving net variable power costs."[205]

In this case, the Company followed the Commission's direction and developed a discrete refinement to de-rate modeling that treats forced outages and de-rates as discrete events, rather than simply applying a uniform de-rate to the plant across all hours.[206] This is a limited adjustment to the overall methodology adopted in docket UM 1355 that produces results that more accurately reflect actual operations.[207]

ICNU and Staff oppose this proposal based largely on their argument that any changes to outage rate modeling must occur in a generic investigation like docket UM 1355.[208] This argument cannot be squared with the Commission's explicit direction to the parties to explore modeling refinements in power cost rate cases, like the TAM.[209] In

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[203] Order No. 10-414.
[204] *Id.* at 7.
[205] *Id.*
[206] PAC/100, Dickman/30-31.
[207] PAC/100, Dickman/30-35.
[208] *See e.g.*, Staff/200, Ordonez/23-24.
[209] Order No. 10-414 at 7.

addition, the de-rate issue in docket UM 1355 was applicable only to PacifiCorp, so it makes little sense to claim that it must be modified in a generic docket.[210] Finally, in the 2013 TAM, Staff supported a refinement to outage rate modeling that was ultimately approved by the Commission without any procedural objections.[211]

There is little dispute that the Company's modeling is superior to the status quo. Indeed, ICNU is the only party to substantively criticize the Company's modeling.[212] But ICNU's criticism lacks credibility given that Mr. Mullins recently recommended that the Wyoming commission "require the Company to use the same methodology that the Company has recently proposed in Oregon."[213]

E. The Company's Decisions to Terminate the Hermiston PPA and Extend the Related Transmission Contract were Reasonable.

ICNU argues that the Company's decision to terminate the Hermiston PPA was imprudent because the Company only evaluated the PPA as a summer peaking resource.[214] ICNU's characterization misstates the Company's reply testimony describing how the Company's Integrated Resource Plan (IRP) modeling and analysis of the Hermiston PPA properly accounted for the west-side winter peak.[215] ICNU's claim of imprudence is also undermined by Mr. Mullins' position in the Company's current Wyoming rate case, where he did not claim that the Company's decision to terminate the Hermiston PPA was imprudent.[216]

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[210] *Id.* at 6-7.
[211] Order No. 12-409 at 12-14.
[212] ICNU/100, Mullins/43-45.
[213] PAC/904 at 2.
[214] ICNU Prehearing Memorandum at 13.
[215] PAC/500, Dickman/73-76.
[216] PAC/904 at 2-5.

ICNU also argues that the Company was imprudent for renewing its BPA transmission contract because the Company did not renew the Hermiston PPA.[217] In testimony both here and in Wyoming, ICNU reasoned that the Company was imprudent because it renewed the transmission contract <u>after</u> deciding not to renew the Hermiston PPA.[218] But this claim is untrue, a fact that ICNU apparently recognizes because ICNU now claims it was imprudent to renew the transmission contract <u>before</u> deciding whether to renew the PPA.[219] ICNU's complete reversal of position betrays the superficiality of its argument.

To keep its options open to renew or terminate the Hermiston PPA, the Company had to renew its transmission contract in advance of the final decision on the PPA.[220] ICNU has not rebutted this fact or any of the Company's evidence that the transmission remains used and useful, both because it is fully utilized at times during the test period and because it provides a long-term benefit that the Company may not have been able to acquire otherwise.[221]

F. The Company's Wind Modeling more Accurately Forecasts Expected Wind Generation.

The Company has proposed two adjustments related to wind generation modeling. First, the Company adjusted the generation level at its Glenrock and Seven Mile Hill wind sites to reflect expected energy lost from curtailment mandated by federal law for avian

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[217] ICNU Prehearing Memorandum at 13.
[218] PAC/904 at 5 ("the Company appears to have renewed the full amount of capacity from this contract <u>after</u> the decision had been made not to extend the Hermiston Purchase contract. . . ") (emphasis in original); ICNU/100, Mullins/43.
[219] ICNU Prehearing Memorandum at 13. ICNU's memorandum contains an error—it states that the Company renewed the transmission contract in September 2014. The Company's testimony states that it renewed the contract in 2013.
[220] PAC/500, Dickman/77.
[221] PAC/500, Dickman/77.

protection.[222] ICNU argues that the Company's wind modeling should be based on the assumptions made when the resources were acquired,[223] even though the Commission has specifically rejected this argument.[224] In addition, ICNU's position here is the exact opposite of its position in other cases, where ICNU proposed a capacity factor "based on the most up-to-date information known at this time."[225] ICNU's prehearing memorandum failed to reconcile its position here with applicable Commission precedent and ICNU's prior inconsistent positions.

Second, the Company modeled generation from the Company's wind PPAs to match actual levels in the 48-month historical period.[226] ICNU criticizes this refinement, but it has supported a five-year rolling average to forecast PGE's wind generation and the Commission has approved this approach.[227] There is no principled basis for ICNU's objection to the Company's wind modeling proposal in this case, which improves the accuracy of the NPC forecast.

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

1. Paying a Credit to Direct Access Customers for Freed-Up RECs Shifts Costs.

Noble Americas Energy Solutions LLC (Noble Solutions) recommends that direct access customers receive a credit reflecting the value of the RECs that are freed-up if a

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[222] PAC/100, Dickman/39-40.

[223] ICNU Prehearing Memorandum at 14.

[224] *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.").

[225] PAC/500, Dickman/80-81 (quoting *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).

[226] 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.

[227] 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).

customer elects direct access.[228] Similar to the Noble Solutions' past, unsuccessful claim for a credit for freed-up transmission, this proposal shifts costs to other customers because the Company cannot reliably realize any net value from the RECs freed-up by direct access.[229]

To credit direct access customers for the value of freed-up RECs, that value must be quantified by selling the RECs.[230] But the Company is required to bank all Oregon RECs not used for RPS compliance,[231] so there is no actual sale from which to measure a benefit.[232]

Noble Solutions recommends that REC prices from 2014 be used to impute a value for RECs that would be freed-up in 2016.[233] Implicit in Noble Solutions' recommendation is an assumption that the Company could realize the same sales price in 2016 that it could realize in 2014. At hearing, however, the Company's witness testified that this assumption is unfounded. The REC market is volatile and illiquid and there is no basis to assume that market conditions in 2014 will be reflective of market conditions in 2016.[234]

Moreover, the Company is not able to sell all of the RECs that it markets and therefore it is pure speculation to assume that Company could actually realize value by selling the freed-up RECs.[235] At hearing, the Company testified that it was able to sell only one-third of its marketed RECs.[236] Therefore, any credit paid must be discounted to reflect the price received per marketed REC, not sold REC—a calculation that Noble Solutions has not attempted in its proposal.

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[228] Pre-Hearing Memorandum of Noble Americas Energy Solutions LLC at 9.
[229] TR. 88-89 (Dickman); TR. 93-94 (Dickman).
[230] TR. 88-89 (Dickman).
[231] *Re PacifiCorp Application for Policy Determination for Sale of Renewable Energy Credits*, Docket No. UP 266, Order No. 11-512 (Dec. 20, 2011).
[232] PAC/500, Dickman/83.
[233] Pre-Hearing Memorandum of Noble Americas Energy Solutions LLC at 10.
[234] TR. 86 (Dickman).
[235] TR. 87 (Dickman).
[236] TR. 91 (Dickman).

Finally, any potential credit that could be realized would be small and is likely outweighed by incremental administrative costs.[237] To provide a credit to direct access customers, remaining customers would have to be surcharged.[238] In addition, the RECs that are hypothetically sold will need to be separately tracked to ensure that if a direct access customer returns to cost-of-service rates, the customer does not receive any benefit from those RECs.[239] Thus, the Company will be required to create multiple REC banks reflecting RECs that are "sold" by each departing direct access customer to remaining customers.

2. The Commission Should Affirm its Decisions in Docket UE 267 Related to the Calculation of the Consumer Opt-Out Charge and the Treatment of Late Direct Access Service Requests.

Noble Solutions asks the Commission to reconsider two aspects of its decision in docket UE 267—the calculation of the consumer opt-out charge and the treatment of late Direct Access Service Requests (DASRs). Noble Solutions' testimony and briefing, however, do not identify any new evidence or arguments since the Commission affirmed its decision in docket UE 267 just three months ago.[240]

Noble Solutions asks the Commission to reconsider its finding 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.[241] To be clear, the Company escalates its fixed generation costs at the average rate of inflation only and, in real terms, holds its fixed generation costs constant through year 10.[242] This treatment is necessary to allow the fixed

[237] TR. 109-110 (Dickman).
[238] TR. 109 (Dickman).
[239] TR. 109-110 (Dickman).
[240] *Re PacifiCorp's Transition Adjustment, Five-Year Cost of Service Opt-Out*, Docket No. UE 267, Order No. 15-195 (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.").
[241] Noble Solutions/100, Higgins/24.
[242] PAC/500, Dickman/84-85.

generation costs to be reduced to a present value for purposes of calculating the consumer opt-out charge.[243] This treatment is also consistent with how the consumer opt-out charge is calculated for years one through five and Noble Solutions has put forth no compelling reason to treat the later years differently.[244]

Noble Solutions' adjustment also unreasonably decreases the consumer opt-out charge even though its witness concedes that only the return on the generation assets should decrease.[245] Noble Solutions' simplistic adjustment ignores the numerous components of the consumer opt-out charge that will increase at a rate greater than inflation in years six through 10.[246]

Noble Solutions also requests that the Commission reconsider its treatment of DASRs that are submitted by an ESS after the deadline set forth in the Commission's rules and the Company's tariff. Noble Solutions claims that there is a "significant risk" that an ESS, like itself, will be unable to comply with the Company's tariff.[247] Yet, Noble Solutions has failed to provide any reasonable explanation why it would be unable to submit a timely DASR. The DASR is electronically submitted and contains information that is readily available to the ESS from the customer.[248]

The Commission's approved treatment of late DASRs ensures that participants in the five-year opt-out program pay the full consumer opt-out charge and reasonably limits the

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[243] TR. 105 (Dickman).
[244] *Re PacifiCorp's Transition Adjustment, Five-Year Cost of Service Opt-Out*, Docket No. UE 267, Staff/100, Compton/6 (Sept. 13, 2013). The Company requests that the Commission take official notice of this testimony under OAR 860-001-0460(1)(d).
[245] Noble Solutions/100, Higgins/24.
[246] TR. 105 (Dickman).
[247] Pre-Hearing Memorandum of Noble Americas Energy Solutions LLC at 15.
[248] Noble Solutions/207; TR. 127 (Ridenour).

administrative costs of the program[249] while still allowing the customer to take service from the ESS through the one-year program[250]. Given that the Company has not held even one enrollment window for the five-year program, there is no evidence that the current treatment of late DASRs is an unreasonable impediment to program participation.

III. CONCLUSION

The Commission should approve PacifiCorp's proposed rate increase of approximately $12.4 million, or one percent overall. The Company's NPC forecast is based on reasonable and conservative modeling that appropriately captures the costs the Company incurs to balance its system in real time and the benefits the Company receives through the EIM. The Commission has directed the Company to continue to refine its NPC modeling and the Company's case here complies with that direction.

Respectfully submitted this 14th day of September, 2015.

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[249] PAC/800, Ridenour/3-4.
[250] PAC/800, Ridenour/3; TR 133 (Ridenour).