PACIFIC POWER
A DIVISION OF PACIFICORP

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August 6, 2012

***VIA ELECTRONIC FILING
AND OVERNIGHT DELIVERY***

Public Utility Commission of Oregon
550 Capitol Street NE, Suite 215
Salem, OR 97310-2551

Attn: Filing Center

Re: UE 245 – PacifiCorp's Prehearing Brief

PacifiCorp d.b.a. Pacific Power hereby submits for filing an original and five (5) copies of its Prehearing Brief.

Please direct informal correspondence and questions regarding this filing to Bryce Dalley, Director, Regulatory Affairs & Revenue Requirement, at (503) 813-6389.

Sincerely,

William R. Griffith /PBD

William R. Griffith
Vice President, Regulation

Enclosures

cc: UE 245 Service List

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 245

In the Matter of: PACIFICORP, dba PACIFIC POWER 2013 Transition Adjustment Mechanism	**PACIFICORP'S PREHEARING BRIEF**

PacifiCorp d/b/a Pacific Power (PacifiCorp or the Company) submits this Prehearing Brief to the Public Utility Commission of Oregon (Commission) in compliance with Administrative Law Judge (ALJ) Shani Pine's ruling on July 17, 2012.

I. INTRODUCTION

PacifiCorp's Transition Adjustment Mechanism (TAM) is an annual filing to update the Company's forecast net power costs to account for changes in market conditions, which allows the Company to capture costs associated with direct access and to identify the proper amount for the transition adjustment for direct access customers.[1] In this TAM filing, PacifiCorp's forecast net power costs (NPC) for 2013 are $363.7 million on an Oregon basis.[2] PacifiCorp requests an order increasing its rates by approximately $3.4 million, or 0.3 percent overall, to reflect the updated forecast. This forecast is subject to a final update in November 2012 for contracts and forward prices. PacifiCorp's new TAM rates will have a January 1, 2013 effective date.

PacifiCorp's NPC forecast is a product of generally uncontroverted market prices, fuel costs, contracts, and generation availability. PacifiCorp's 2013 TAM is straightforward because the projected cost increases for certain NPC factors are mostly offset by projected

[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/300, Duvall/2, lines 10-11.

cost decreases for other NPC factors. The small rate increase remaining is tied to a forecast decrease in Oregon loads, an issue that no party has contested.

Staff and the intervenors in this docket propose various adjustments to PacifiCorp's proposed NPC that collectively would reduce PacifiCorp's proposed NPC by approximately $7.2 million on an Oregon basis and decrease rates by approximately $3.8 million. None of these adjustments contest the core elements of NPC or assert that PacifiCorp was imprudent in managing NPC. Instead, the adjustments are technical in nature, challenging PacifiCorp's NPC modeling in the Generation and Regulation Initiative Decision (GRID) model, an hourly production dispatch model used in all of PacifiCorp's Oregon rate filings since 2002.[3]

Specifically, parties challenge short-term firm sales volumes, arguing that these sales should not be capped at any level in the GRID model, even levels that are based upon historical average sales volumes. Parties also challenge the modeling of margins on arbitrage sales and trading and hydro generation forced and planned outages. Additionally, parties seek certain policy-based adjustments to PacifiCorp's NPC, challenging recovery of third-party wind integration costs and seeking changes to the transition adjustment calculation to benefit direct access customers.

PacifiCorp respectfully requests approval of its proposed 2013 TAM increase and rejection of the adjustments proposed by Staff and the intervenors. The adjustments are not supported by compelling policy arguments or by evidence demonstrating that PacifiCorp was unreasonable or imprudent. Most importantly, Staff's and the intervenors' adjustments do not result in an accurate forecast of PacifiCorp's actual NPC. PacifiCorp's NPC in rates have been *understated* every year since the inception of the TAM, resulting in under-recovery of

[3] PAC/100, Duvall/11, lines 17-22; PAC/300, Duvall/11, lines 11-12.

over one-half billion dollars in system NPC during this period.[4] Moreover, because the transition credit or charge for direct access is based upon PacifiCorp's NPC in rates, the understatement of power costs in rates results in the over-valuation of the transition credit or the under-valuation of the transition charge for customers considering direct access.[5] Adoption of any of the NPC adjustments proposed in this case increases the risk that this under-recovery and inaccurate valuation will continue in 2013, which could impermissibly shift costs from direct access to cost-of-service customers.

II. BACKGROUND

On February 29, 2012, PacifiCorp filed its initial filing in the 2013 TAM (Initial Filing). The TAM is "an annual filing, updating the Company's forecast net power costs to account for changes in market conditions, with the final forecast update close to the direct access window to capture costs associated with direct access and to identify the proper amount for the transition adjustment."[6] The scope and procedures of the TAM are governed by Commission-approved TAM Guidelines.[7] The Company filed the 2013 TAM

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[4] PAC/300, Duvall/3, lines 7-10.

[5] The transition adjustment is the difference between the Company's cost-of-service rate and market prices. OAR 860-038-0005(67)-(69). The Company offers a transition credit to direct access customers when the Company's cost-of-service rate is lower than market prices. In this scenario, if actual NPC are higher than NPC in rates, the Company's transition credit will be overstated (*i.e.,* the Company will pay more to direct access customers than is actually due). The Company sets a transition charge for direct access customers when the Company's cost-of-service rate is higher than market prices. In this scenario, if actual NPC are higher than NPC in rates, the transition charge will be understated (*i.e.*, the Company will collect less from direct access customers than is actually owed). In both scenarios, when actual NPC are higher than NPC in rates, the transition adjustment will shift costs from direct access customers to retail customers, contrary to Commission policy. *See In the Matter of PacifiCorp, dba Pacific Power, 2008 Transition Adjustment Mechanism*, Docket No. UE 191, Order No. 07-446 at 1-2 (October 17, 2007).

[6] Order No. 09-274 at 2.

[7] The TAM Guidelines were presented to the Commission in a stipulation filed in Docket No. UE 199 and approved in Order No. 09-274 (Appendix A at 9-19). In Docket No. UE 207, the TAM Guidelines were clarified and amended. *In the Matter of PacifiCorp, dba Pacific Power, 2010 Transition Adjustment Mechanism*, Docket No. UE 207, Order No. 09-432, Appendix A at 5 (October 30, 2009). One aspect of the Guidelines—challenges to the Final Update—was addressed in Docket No. UE 216. *In the Matter of PacifiCorp, dba Pacific Power, 2011 Transition Adjustment Mechanism*, Docket No. UE 216, Order No. 10-363, Appendix A at 5-6 (September 16, 2010).

concurrently with a request for a general rate increase, Docket UE 246 (2012 GRC), and followed the applicable TAM Guidelines.[8]

PacifiCorp's NPC are calculated based on projected data from the GRID model.[9] To forecast the 2013 TAM, the Company updated the following model inputs: system load, wholesale sales and purchase power expenses, wheeling expenses, market prices for natural gas and electricity, fuel expenses, and the characteristics and availability of the Company's generation facilities.[10]

The Initial Filing reflected total forecasted normalized system-wide NPC of approximately $1.504 billion for the 12-month test period ending December 31, 2013,[11] or approximately $370.2 million on an Oregon basis.[12] The Company's Initial Filing forecast an increase in Oregon NPC of $3.5 million for 2013.[13] Adjusted for the forecast decrease in Oregon loads in 2013 as required by the TAM Guidelines,[14] the Company proposed an increase in rates of $9.9 million, or approximately 0.8 percent.[15]

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) filed opening testimony responding to the Company's Initial Filing on June 6, 2012. Staff and the intervenors propose six adjustments, of which the following five remain contested: (1) Staff and ICNU each proposed an adjustment to remove the caps on market sales in GRID, reducing Oregon NPC by approximately $3.8 million; (2) Staff, ICNU, and CUB opposed the Company's proposed

[8] PAC/100, Duvall/26.
[9] PAC/100, Duvall/11, lines 16-18.
[10] PAC/100, Duvall/12, lines 5-8.
[11] PAC/100, Duvall/2, lines 16-17.
[12] PAC/100, Duvall/3, lines 3-4; Exhibit PAC/101.
[13] PAC/100, Duvall/3, line 13.
[14] Order No. 09-274, Appendix A at 13, § D.4.
[15] PAC/100, Duvall/3, lines 13-16.

removal of an adjustment originally imposed in Docket UE 191, imputing a revenue credit for arbitrage sales and trades allegedly not captured in the GRID model, reducing Oregon NPC by $0.6 million; (3) Staff and ICNU proposed adjustments to the Company's hydro forced outage modeling of $0.3 million and $0.5 million, respectively, and Staff proposed an adjustment of $0.7 million for hydro planned outages; (4) ICNU proposed an adjustment removing third-party wind integration charges, reducing Oregon NPC by $1.5 million; and (5) Noble Solutions proposed changes to the transition adjustment calculation, seeking a credit for Bonneville Power Administration (BPA) transmission of $1.422/MWh and a relaxation of market caps.

The Company filed reply testimony on July 11, 2012 (Reply Update). The Company made corrections and updated NPC to reflect the June 29, 2012 official forward price curve and new power, fuel, and transportation/transmission contracts and updates to existing contracts, consistent with the TAM Guidelines. In the Reply Update, the Company accepted Staff's adjustment related to dispatch modeling at the Chehalis generating facility,[16] reducing Oregon NPC by approximately $0.2 million. The Company also accepted ICNU's adjustment to remove the costs of integrating generation from the Rolling Hills wind farm from the Company's calculation of wind integration costs.[17] This adjustment reduced Oregon NPC by approximately $0.9 million.

The Reply Update reduced the Company's 2013 TAM to $1.476 billion in system NPC, a decrease from the Initial Filing of approximately $28 million.[18] On an Oregon-allocated basis, the Company's NPC decreased by $6.5 million to $363.7 million, resulting in a revised TAM proposed rate increase of $3.4 million or 0.3 percent. The Company's system

[16] Staff/100, Schue/26, lines 3-4.
[17] ICNU/100, Deen/15.
[18] PAC/300, Duvall/2, lines 5-6.

NPC of $1.476 billion in this case is now approximately $19 million *lower* than the $1.495 billion NPC from the 2012 TAM. This 2012 NPC was reduced by a $32 million settlement adjustment,[19] producing in-rates system NPC of $1.463 billion.[20] After applying the settlement adjustment, system NPC in this case are now approximately $13 million higher than the adjusted NPC from the 2012 TAM. These comparisons show that forecast NPC is flat to declining, with the modest increase in the 2013 TAM attributable to uncontested reductions in Oregon retail loads.

On July 12, 2012, some parties to the 2012 GRC filed a partial stipulation. The stipulating parties resolved cost of service and rate spread by agreeing to the allocation of base and net revenues by rate schedule as presented on page one of Exhibit D to the partial stipulation. The stipulating parties also agreed that the Company would use the generation allocation factors on page four of Exhibit D to determine rate spread in this case.[21] The Company requests that the Commission take official notice of the partial stipulation under OAR 860-001-0460(1)(d) and include it in the record in this case.

III. ARGUMENT

A. The Adjustments of Staff and Intervenors Understate NPC and Would Produce an Unreasonable Overall Result if Adopted.

It is important that this case produce the most accurate NPC forecast possible to meet the Commission's goals for the TAM,[22] and to set fair, just and reasonable rates.[23] There are several factors demonstrating the overall reasonableness and accuracy of the forecast NPC in

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[19] *In the Matter of PacifiCorp, dba Pacific Power, 2012 Transition Adjustment Mechanism*, Docket No. UE 227, Order No. 11-435, Appendix A at 3 (November 4, 2011).
[20] PAC/100, Duvall/2, lines 16-21.
[21] *In the Matter of PacifiCorp, dba Pacific Power, Request for a General Rate Revision*, Docket No. UE 246, Partial Stipulation, ¶ 16 (filed July 12, 2012).
[22] PAC/300, Duvall/4-5.
[23] *See* ORS 756.040.

the Company's 2013 TAM. These same factors reveal the unreasonableness of Staff's and the intervenors' proposed adjustments to Company's 2013 NPC.

First, no party has challenged any of the fundamentals of the Company's NPC forecast. The Company's direct filing detailed the cost drivers behind the 2013 TAM, explaining that declining wholesale sales and rising coal costs increased NPC, while decreasing natural gas and purchased power expense largely offset these increases.[24] The filing also outlined the reduction in Oregon retail loads of 371 GWh, and the resulting $6.4 million revenue shortfall due to the load variance between the 2012 TAM, Docket UE 227, and the 2013 TAM.[25] Staff and the intervenors do not contest these aspects of the Company's NPC forecast, nor has any party raised the major issue from the 2012 TAM—the prudence of the Company's natural gas hedges.

Second, the Company made a number of refinements to its GRID model to increase the accuracy of the NPC forecast and proactively respond to the anticipated concerns of Staff and the intervenors. Most notably, the Company included its new market caps methodology, first introduced in the 2012 TAM. The Company also modeled transactions with the California Independent System Operator (Cal ISO) in response to ICNU's Cal ISO adjustment in the 2012 TAM;[26] removed the must-run designation from Gadsby peaking units 4, 5, and 6;[27] added the DC Intertie to the GRID topology; input normalized hydro generation into GRID on a weekly rather than monthly basis;[28] and continued to model the Bear River hydro project in the manner proposed by Staff and ICNU in the 2012 TAM.[29]

[24] PAC/100, Duvall/4.
[25] PAC/100, Duvall/3, 7.
[26] PAC/100, Duvall/13, lines 9-18.
[27] PAC/100, Duvall/14, lines 1-6.
[28] PAC/100, Duvall/13, lines 1-4.
[29] PAC/300, Duvall/5, lines 18-21.

Because NPC in this case already reflect downward adjustments for many of the issues raised in the 2012 TAM, further adjustments to NPC are unreasonable.

Third, the Company has chronically under-recovered actual NPC in Oregon rates for many years.[30] Although the Company makes every effort to accurately forecast NPC for the test period, the inherent volatility of key NPC inputs results in a bias towards the under-forecast of NPC in rates.[31] Adopting Staff's and the intervenors' modeling adjustments in this case would compound the bias towards under-forecasted NPC and produce an artificially low overall level of NPC. The two largest adjustments in this case—market caps and third-party wind integration costs—eliminate costs previously recoverable in Oregon NPC. Staff and ICNU have not shown that these adjustments increase the overall accuracy the 2013 NPC forecast. All else equal, the proposed adjustments would widen the Company's recovery shortfall and decrease the accuracy of the Company's projected NPC.[32]

The Commission has previously recognized the need to look at all factors in considering NPC adjustments, including whether the dispatch model generally underestimates NPC. For example, based upon evidence of under-forecast bias in Portland General Electric Company's NPC model, the Commission rejected an NPC adjustment for unaccounted-for extrinsic value.[33]

B. The Company's Continued Use of Market Caps in GRID is Necessary to Replicate the Company's Actual Operations.

Market caps are an important input to GRID because they reflect actual wholesale power market constraints and limit GRID's default assumption of unlimited market depth for

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[30] PAC/300, Duvall/3, lines 7-10.
[31] PAC/300, Duvall/4, lines 4-6.
[32] PAC/300, Duvall/4, lines 11-17.
[33] *In re Portland General Electric Company*, Docket Nos. UE 180/UE 181/UE 184, Order No. 07-015 at 12 (January 12, 2007).

short-term firm (STF) sales. In this case, both Staff and ICNU oppose the use of market caps in GRID and argue for their complete removal, resulting in a $15.5 million increase in imputed wholesale revenues and a concomitant imputed reduction in system NPC.[34] In the alternative, Staff presents an alternative market caps structure that changes how the caps are calculated, which would reduce system NPC by $7.7 million.[35] As detailed below, the Company has followed the Commission's directive in the 2012 TAM and provided clear and robust evidence justifying its modeling of market caps.[36] For this reason, the Commission should authorize the Company's continued use of market caps.

1. The Company's Use of Market Caps is Consistent with Historical Practice.

The Company has used market caps to model Oregon NPC since GRID was first introduced in Docket UE 134 in 2002.[37] In addition, market caps have been litigated and approved before other state commissions.[38] Neither Staff nor ICNU has demonstrated any problems associated with the historical usage of market caps in Oregon or explained why market caps should be removed now, especially after the Company refined its approach to the caps in response to ICNU's proposed market caps adjustment in the 2010 TAM (Docket UE 207).

In Docket UE 191, the Commission rejected an ICNU proposal to change the Company's approach to modeling the capacity of a plant on a similar basis: "We defer to the

[34] ICNU/100, Deen/11, lines 5-6; Staff/100, Schue/5, lines 5-8.
[35] Staff/100, Schue/16-17.
[36] Order No. 11-435 at 23.
[37] PAC/300, Duvall/11, lines 11-12
[38] PAC/300, Duvall/11, lines 15-17; *See also Re Application of PacifiCorp for a Retail Electric Utility Rate Increase*, Wyoming PSC Docket No. 20000-ER-03-198 ¶ 45(b) (Feb. 28, 2004); *Re Application of Rocky Mountain Power for Authority to Increase its Retails Utility Service Rates in Utah*, Docket No. 09-035-23, Report and Order on Revenue Requirement, Cost of Service, and Spread of Rates at 27 (Feb. 18, 2010).

Company's judgment where it has been running the model using [this approach] for several years and ICNU has not shown that the results are unreasonable."[39]

2. Market Caps Are Necessary to Accurately Reflect Actual Market Conditions.

GRID assumes unlimited market depth for STF transactions; it does not consider load requirements, all actual transmission constraints, market illiquidity, or static assumptions about market prices that would preclude sales at the forecast price.[40] Market caps are necessary to account for these actual market constraints to ensure that GRID does not model transactions and impute sales revenues that, in reality, are not available to the Company. In the 2012 TAM, the Commission directed the Company to demonstrate that the use of market caps was "reasonably representative of the company's actual operations."[41] The Company's testimony and exhibits in this case demonstrate that market caps are necessary to accurately reflect the Company's operations.[42]

Most fundamentally, the Company's market caps are reasonably representative of the company's actual operations because they are based upon the Company's actual average historical sales levels during the preceding four-year period. In other NPC contexts, the Commission has recognized that past performance over a four-year rolling average is the best predictor of future performance.[43]

Additionally, it is undisputed that GRID overestimates actual physical sales and that market caps moderate this overestimation.[44] The Company's testimony demonstrates that,

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[39] Docket No. UE 191, Order No. 07-446 at 26 (October 17, 2007).
[40] PAC/100, Duvall/18, lines 10-13.
[41] Order No. 11-435 at 23.
[42] *See, e.g.,* PAC/100, Duvall/20, Table 5.
[43] *See, e.g.,* Order 07-015 at 15 ("We continue to believe that past performance is the best predictor of a plant's outage rate. For this reason, we adhere to our long-standing practice of using actual plant outage rates to predict the future activity of a plant.")
[44] PAC/100, Duvall/20, Table 5.

even with market caps in place, GRID overestimates actual wholesale sales volumes.[45] Thus, market caps are essential if GRID is to be "reasonably representative of the company's actual operations."[46]

ICNU argues that the only reason that GRID consistently overestimates wholesale sale volumes is because the Company excludes "bookouts" in the calculation of sales volumes.[47] Bookouts are purely financial transactions that are offsetting at the same market hub, involve no physical delivery, and do not change total NPC.[48] Because GRID models only physical transactions, bookouts are not included in GRID's modeling,[49] nor included in the Company's wholesale data reported in its FERC Form 1.[50] In the 2010 TAM, ICNU's witness testified that bookouts distort transaction volumes,[51] a fact demonstrated by ICNU's calculations in this case. Removing bookouts from ICNU's calculation of historical transactions demonstrates clearly that GRID overestimates transaction volumes.[52] Staff argues that the market caps in GRID result in the exclusion of certain actual sales above the caps.[53] However, as demonstrated by the Company's analysis, if the market caps were removed in order to capture the small subset of actual sales that exceed the caps, the results would be a dramatic overestimation of sales.[54] GRID models sales on an optimized basis, so it produces more sales up to cap than occur on an actual basis. In other words, Staff's proposal would capture these excluded sales above the cap, but it would also model substantially more sales under the cap that did not actually occur. Thus, as the evidence

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[45] PAC/300, Duvall/18, Figures 1 and 2; 19, lines 1-4.
[46] Order No. 11-435 at 23.
[47] ICNU/100, Deen/7, Table 2; ICNU/100, Deen/8, lines 2-3.
[48] PAC/300, Duvall/15, lines 2-5.
[49] PAC/300, Duvall/15, lines 2-4.
[50] PAC/300, Duvall/15, lines 4-5.
[51] Docket No. UE 207, ICNU/100, Falkenberg/8, lines 15-16.
[52] PAC/300, Duvall/16, Table 2.
[53] Staff/100, Schue/12, Graph 4.
[54] PAC/300, Duvall/19, lines 5-11.

demonstrates, Staff's proposal to remove market caps would introduce substantially more error into the model than it would correct.

3. Market Caps Are Necessary to Capture Actual Market Illiquidity.

One of the fundamental purposes of market caps is to ensure that GRID accounts for actual market illiquidity demonstrated by the Company's actual historical sales levels. The only evidence in the record disputing the Company's position on market illiquidity is ICNU's exhibit purporting to show PacifiCorp's market share at the six market hubs modeled in GRID.[55] ICNU claims that the Company's limited market share means that these markets are liquid at all times and should therefore be modeled as such in GRID.[56] However, PacifiCorp's market share in ICNU's exhibit varies widely by hub and by quarter. Without additional information on market participants and other dynamics, it is difficult to draw any conclusions on actual market liquidity from the exhibit.[57]

Further cutting against ICNU's argument are ICNU's previous admissions regarding market liquidity problems at several of the Company's market hubs. For instance, in the 2012 TAM, ICNU discussed development of a new forward price curve using data from IntercontinentalExchange, Inc. (ICE), and testified that ICE did not provide forward price curves for the Company's "less liquid hubs:" California-Oregon Border (COB), Four Corners, Mead, and Mona.[58] Similarly, in the 2010 TAM, ICNU accepted the market cap for the Mona hub because of the small size of the market;[59] ICNU also expressly relied on

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[55] Confidential ICNU/103.
[56] ICNU/100, Deen/9-10.
[57] PAC/300, Duvall/20, lines10-12.
[58] Docket No. UE 227, Highly Confidential ICNU/100, Schoenbeck/18. ICNU's testimony in the 2012 TAM designated as confidential the identity of the four market hubs for which ICE does not provide forward price curves. The Company's rebuttal testimony in that case, however, clarified that this information was not confidential. *See* Docket No. UE 227, PPL/500, Link/6-7.
[59] Docket No. UE 207, ICNU/100, Falkenberg/11-14, citing Direct Testimony of Mark Widmer in Wyoming Docket No. 2000-341-EP-09.

testimony from another case conceding that a market cap at Mona was necessary due to the illiquidity of that market.[60]

The Company has produced evidence showing how the removal of market caps affects sales in each market hubs.[61] Not surprisingly, the greatest impact is at the hubs with the least liquidity: COB, Four Corners, Mead and Mona. The historical data that the Company used to determine market depth shows that the Company's ability to sell in these markets is constrained, and the Company's market caps appropriately reflect this fact.[62]

4. The Refined Market Caps Included in the 2013 TAM are Consistent with ICNU's Past Recommendations.

The market caps in this case are modeled using the Company's new approach—setting market caps in all hours based on a four-year average of historical sales transactions. This general design for market caps was recommended by ICNU witness Randall Falkenberg in the 2010 TAM. The Company's new approach results in a more accurate and comprehensive model of the power markets in which the Company transacts.

Before the 2012 TAM, the Company capped sales during graveyard hours at four major wholesale markets—Mid C, COB, Four Corners, and PV.[63] The Company has historically capped the Mona market in all hours.[64] The caps were based upon average spot market sales. In the 2010 TAM, ICNU challenged the Company's market caps methodology, arguing that a "more proper analysis is to compare the total STF and balancing sales in GRID to recent actual results."[65] ICNU argued that the previous methodology was too limited because the caps were based on only spot market transactions and not on all STF

[60] Docket No. UE 207, ICNU/100, Falkenberg/11-14, citing Direct Testimony of Mark Widmer in Wyoming Docket No. 2000-341-EP-09.
[61] PAC/304.
[62] PAC/300, Duvall 21, lines 5-10.
[63] PAC/100, Duvall/19, lines 7-10.
[64] PAC/100, Duvall/19, line 10.
[65] Docket No. UE 207, ICNU/100, Falkenberg/13.

transactions.[66] ICNU also claimed that for market caps to be consistent, they should be applied during all hours, not just during graveyard hours.[67]

In response to these two criticisms, in the 2012 TAM the Company adopted ICNU's proposals, applying caps to all hours and calculating the caps based on a four-year average of total short-term wholesale sales.[68] Under the new approach, the Company continues to cap sales at the Mid C, COB, Four Corners, and PV hubs while also adding consistent market caps at the Mona and Mead hubs.[69] For these six markets, the Company specified market depth in all hours, segregated by heavy load hours (HLH) and light load hours (LLH), and based the cap on a four-year historical average of STF, balancing, and spot sales.[70] The Company's new market caps design reduced NPC in the 2012 TAM filing by $10 million, as compared to the Company's prior market caps model.[71]

Both Staff and ICNU objected to the Company's refined market caps methodology in the 2012 TAM because, among other reasons, the new approach represented a change in methodology that was improperly introduced in a stand-alone TAM proceeding. In the order in that docket, the Commission approved the Company's approach to market caps on a non-precedential basis, directed Staff to hold workshops to attempt to resolve the market caps issue, and, if no agreement was reached, directed Staff and the Company to provide additional analysis and evidence on the issue of market caps in the next TAM.[72]

In the 2013 TAM, the Company re-introduced its refined market caps methodology. As compared to PacifiCorp's prior market caps, the new approach represents a compromise

[66] *Id.* at 10.
[67] *Id.* at 10-11.
[68] PAC/300, Duvall/12, lines 2-5.
[69] PAC/100, Duvall/19, lines 16-17.
[70] PAC/100, Duvall/19, lines 18-21.
[71] PAC/300, Duvall/12, lines 5-6.
[72] Order No. 11-435 at 23.

position that responds to ICNU's past criticisms and reduces the system NPC impact of market caps by $4 million.[73]

5. The Use of Monthly HLH and LLH Averages are Proper.

The Company calculates the market caps based upon a four-year historical average of short-term wholesales sales levels.[74] Both Staff and ICNU argue that market caps should be based on hourly sales levels instead of monthly heavy load and light load averages.[75] However, neither Staff nor ICNU provide evidence that such an approach more accurately reflects the Company's actual sales. In fact, the Company modeled market caps on an hourly basis, and the results show that GRID overestimates total actual wholesale sales volume.[76] Although the Company's hourly modeling shows GRID underestimating a small number of sales transactions at very high volumes, overall results of hourly modeling still show that elimination of market caps would result in a significant overestimation of sales in GRID.

6. Removal of Market Caps Will Result in Dramatic Overstatement of Short-Term Sales.

Removal of market caps from GRID would result in a 23 percent increase in the number of short-term sales.[77] Coupled with the fact that GRID already overestimates actual sales, this increase will further distort the Company's modeling and unreasonably reduce NPC.

Staff claims that removal of market caps would not dramatically increase the number of sales. Staff acknowledges that the increase in sales would be 2,500 GWh on an Oregon basis, but suggests this is a small amount in comparison with the Company's total six-state

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[73] PAC/300, Duvall/12, lines 21-23.
[74] PAC/100, Duvall/19, lines 18-21.
[75] ICNU/100, Deen/8, lines 6-8.
[76] PAC/300, Duvall/18, Figures 1 & 2.
[77] PAC/300, Duvall/16, lines 8-9.

system load.[78] Instead of comparing to total load, a more apt comparison is to the total Oregon industrial sales forecast for 2013—2,300 GWh. Removal of market caps adds new sales in GRID in excess of Oregon's total industrial load, an increase that is clearly substantial.[79]

7. Removal of Market Caps will Result in GRID Overstating Coal Generation.

Contrary to ICNU's claims,[80] removing market caps from GRID will also produce an unreasonable increase in coal generation. ICNU's own analysis[81] shows that even with market caps in place, GRID already produces more coal generation than the historical actual generation in both the most recent 12-month period and in the 48-month average.[82] The complete removal of market caps from GRID will result in an even greater increase in coal generation over historical actual levels, further decreasing the accuracy of the NPC forecast.

8. Generation and Transmission Constraints Modeled in GRID do not Adequately Restrain Market Transactions in the Absence of Market Caps.

ICNU argues that sales levels are naturally constrained by the energy generated from the Company's resources and wheeling limitations, making market caps unnecessary.[83] ICNU's argument, however, is undercut by ICNU's conclusion that the vast majority of the additional sales in GRID when market caps are removed are supplied from market purchases, not from the Company's generation facilities.[84] Limitations on the Company's generation capacity and associated transmission do not restrict these incremental market purchases.

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[78] Staff/100, Schue/6, lines 19-22.
[79] PAC/300, Duvall/16, lines 12-15.
[80] ICNU/100, Deen/10, lines 17-18.
[81] ICNU/104.
[82] Id. *See also* PAC/300, Duvall/21, lines 14-20.
[83] ICNU/100, Deen/10, lines 1-12.
[84] ICNU/100, Deen/10, lines 19-21.

9. Removal of Market Caps will Reduce NPC to Unreasonable Levels.

If market caps are completely removed from GRID as Staff and ICNU advocate, the total number of over-estimated sales will increase and the accuracy of the NPC forecast will decrease. The TAM is designed to set NPC in the most accurate and up-to-date manner possible to enable the calculation of transition adjustments that do not shift costs between cost-of-service and direct access customers. It is unreasonable to eliminate a feature of GRID that results in NPC forecasts that more closely align with actual operations. Moreover, neither Staff nor ICNU have presented any evidence that overall NPC is overstated as the result of market caps.

10. Staff's Alternative Market Caps Proposal is Unreasonable.

Staff proposes an alternative market caps adjustment based on a compromise market caps structure discussed at the January 11, 2012, workshop.[85] The alternative proposal sets market caps based on the highest transaction level for a particular month contained in the four-year average, as compared to the Company's current proposal which sets the caps based on the average of monthly results.[86]

Staff's testimony notes that its alternative proposal represents "a sort of middle ground" that "results in a 2013 NPC forecast approximately half way between the results the approaches advocated by the Company and by Staff."[87] While this may be true in terms of impact on NPC, Staff's proposal does not represent a compromise in terms of designing market caps that accurately represent the Company's operations. This proposal would allow

[85] Staff/100, Schue/16, lines 19-20.
[86] Staff/100, Schue/16-17.
[87] Staff/100, Schue/18, lines 6-9. This alternative proposal reduces NPC by $7.7 million. Staff also qualifies its market caps adjustment by agreeing to support elimination of the arbitrage and trading revenue credit if Staff's primary market cap adjustment—complete removal of market caps—is adopted. Staff/100, Schue/20, lines 1-6. Including Staff's request to maintain the arbitrage and trading credit increases the amount of Staff's alternative market cap adjustment by $2.3 million, reflecting the value of the arbitrage and trading revenue credit, for a total $10 million system NPC reduction.

GRID to unreasonably inflate sales volume up to the maximum transaction level for a particular month over four years. This approach will overestimate transaction volumes and is inconsistent with basic principles of normalized ratemaking. Staff's alternative proposal should be rejected as an attempt to make market caps less restrictive without regard to whether the redesigned caps replicate actual market conditions.

11. ICNU's Alternative Proposal is Indistinguishable from its Proposal to Remove Market Caps Altogether.

If market caps are included in GRID, ICNU proposes that the caps be based on the maximum historical hourly transactional volumes at each hub.[88] This proposal is completely meritless as an alternative because, as a practical matter, it results in the same outcome as eliminating the caps altogether.[89] If the cap is set at the highest level transacted, then by definition it will never act as a constraint on GRID's ability to model unlimited sales. Thus, ICNU's "compromise" proposal goes against the basic purpose of the market caps and compromises nothing.

C. The Arbitrage and Trading and Revenue Credit is Obsolete and Unreasonable.

As the result of improvements in how the Company models STF transactions in GRID, the Company proposes calculating NPC without a revenue credit for actual arbitrage and trading transactions within a 48-month historical period. ICNU and CUB both oppose the Company's proposal.[90] Staff supports the Company's proposal to remove the arbitrage and trading revenue credit only if market caps are removed from GRID.[91] Including the arbitrage and trading revenue credit lowers system NPC by approximately $2.5 million,[92]

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[88] ICNU/100, Dean/12, lines 5-9.
[89] PAC/300, Duvall/13, lines 11-19.
[90] ICNU/100, Deen/5, lines 20-22; CUB/100, Jenks-Feighner/3.
[91] Staff/100, Schue/20, lines 1-3.
[92] The intervenors' adjustment in this case is based upon the Company's response to ICNU 2.14, which is referenced in ICNU/102, Deen/2. The original response to ICNU 2.14 calculated a $2.3 million adjustment.

largely due to transactions dating back to 2007.[93] As discussed below, the Commission should approve the Company's proposal to remove the revenue credit because the conditions underlying the imposition of the revenue credit no longer exist.

In the Company's 2008 TAM, the Commission adopted an adjustment to impute a profit margin on certain STF transactions not modeled in GRID.[94] The Commission's decision was based on two findings: (1) GRID systematically understates wholesale sales volumes as compared to historical actual volumes; and (2) arbitrage transactions were not included in GRID.[95] The conditions justifying an arbitrage adjustment no longer exist. Since the 2008 TAM, the Company has added both STF transmission and non-firm transmission to GRID's topology. GRID no longer underestimates wholesale sales volumes[96] and, in fact, overestimates these sales volumes. The transactions covered by this adjustment have been steadily declining, along with the associated revenue credit, suggesting that this revenue credit will soon become de minimus.[97]

ICNU's argument to the contrary relies on ICNU's erroneous calculation of actual sales volumes.[98] As it did with market caps, ICNU improperly includes bookouts in its calculation of actual sales volumes, resulting in an over-statement of actual sales.[99] In addition, GRID reflects equivalent arbitrage and trading revenues; including an arbitrage adjustment would improperly inflate the level of sales and revenue credit included in

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The Company served a revised response to ICNU 2.14 that provided a corrected calculation of $2.5 million for this adjustment.

[93] PAC/300, Duvall/22, lines 16-17.

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

[95] *Id.*

[96] PAC/100, Duvall/20, Table 5; Pac/100, Duvall/22, lines 19-22.

[97] Confidential ICNU/102, Deen/3.

[98] ICNU/100, Deen/5, lines 3-4.

[99] ICNU/100, Deen 5, lines 7-8.

GRID.[100] ICNU argues that the arbitrage sales are not modeled in GRID, but fails to account for transactions that serve as proxies for future STF transactions—system balancing sales and purchases.[101]

CUB argues that the arbitrage adjustment acts as a safeguard for customers.[102] CUB acknowledges that GRID currently "greatly overestimates" wholesale sales volumes compared to actual sales volumes,[103] but ignores the safeguard this overestimation already builds into GRID—significant overestimation of sales compared to actual sales ensures that the actual volume of arbitrage sales is captured in GRID. An additional safeguard is therefore unnecessary.

As noted by Staff, the revenue credit is controversial and introduces volatility into the results of NPC.[104] These factors support the Company's proposal to eliminate the revenue credit.

D. Inclusion of Third-Party Wind Integration Costs is Appropriate.

The Company includes approximately $3.87/MWh in NPC costs for integrating wind generation in the Company's balancing authority areas. ICNU proposes removing costs associated with integration of third-party wind generation.[105] The impact of ICNU's adjustment reduces system NPC by approximately $6.1 million.

As discussed above, a partial stipulation has been filed in the Company's 2012 GRC, and the Company has requested official notice of the stipulation in this case.[106] The partial stipulation requires PacifiCorp to file an application for deferred accounting for the Oregon-

[100] PAC/300, Duvall/23, lines 14-16.
[101] ICNU/100, Deen/5, lines 14-22.
[102] CUB/100, Jenks-Feighner/2, lines 19-22.
[103] CUB/100, Jenks/Feighner/2, lines 14-15.
[104] Staff/100, Schue/19, lines 7-10.
[105] ICNU/100, Deen/15, lines 14-16.
[106] Docket No. 246, Partial Stipulation at 5-6.

allocated share of the incremental Open Access Transmission Tariff (OATT) revenues associated with PacifiCorp's pending rate case at the Federal Energy Regulatory Commission (FERC), Docket No. ER11-3643-000. PacifiCorp will file the deferred accounting application upon approval of the partial stipulation; the application will request that the deferral begin on January 1, 2013, and continue until the revenues are included in base rates.[107]

Under the partial stipulation, customers will be credited for incremental revenues from ancillary services charges approved by FERC, including the fixed costs associated with third-party wind integration. Thus, to the extent PacifiCorp is allowed to recover charges for these services under its OATT, these revenues will flow through to Oregon retail customers.

ICNU argues that costs associated with integration of third-party wind generation should be removed from NPC because retail customers receive no benefit associated with these costs.[108] If the partial stipulation is approved, customers will receive benefits in the form of incremental revenues for third-party wind integration charges approved by FERC.

In addition, third-party integration costs are incurred because of the Company's status as a balancing area authority, and customers benefit from the Company being a balancing authority. The Company's transmission network spans 10 states and is connected to over 83 generating units and 12 adjacent control areas at 153 interconnection points.[109] Because of the Company's expansive system and status as a balancing area authority, the Company avoids incurring additional wheeling and expenses from third-party transmission providers—savings that constitute a direct benefit to retail customers.

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[107] Docket No. UE 246, Partial Stipulation, ¶ 13 (filed July 12, 2012).
[108] ICNU/100, Deen/15, lines 15-16.
[109] PAC/300, Duvall/29, lines 14-17.

ICNU also claims that the Company should be recovering these costs from transmission customers under the Company's OATT. ICNU makes this claim without citing a single instance where a utility was able to fully recover these types of charges under its OATT. As noted above, the Company has sought recovery of the fixed portion of these charges in its currently pending FERC rate case.

ICNU claims that PacifiCorp "voluntarily" chose to not seek recovery of the variable portion of these charges.[110] This claim is untrue. The most recent FERC decision on this issue, FERC Order No. 764 in Docket No. RM10-11-000 issued on June 22, 2012, confirms that the Company's FERC rate case filing was as broad as currently allowed by FERC, absent the adoption of operational system enhancements.[111] The limitations on the scope and span of PacifiCorp's OATT charges and revenues are a result of FERC requirements and not a lack of due diligence on the part of the Company.

While ICNU attempts to show that other jurisdictions—specifically Washington and Idaho—have resolved this issue by disallowing recovery of third-party wind integration costs,[112] these decisions are inapposite. The decisions of the Washington and Idaho commissions were issued before the Company filed its FERC rate case or implemented a means (the deferred account discussed above) to include incremental OATT revenues from the FERC rate case in retail rates. In addition, ICNU ignores favorable precedent from the Utah commission allowing third-party wind integration charges.[113]

[110] ICNU/100, Deen/16, lines 15-17.
[111] PAC/300, Duvall/31-32.
[112] ICNU/100, Deen/16, lines 1-5 (citing *Re Rocky Mountain Power 2010 General Rate Case*, Idaho Public Utility Commission, Case No. PAC-E-10-07, Order No. 32196 at 30 (Feb. 28, 2011); *Washington Util. & Transp. Comm'n v. PacifiCorp*, Docket No. UE-100749, Order No. 06, ¶ 125 (Mar. 25, 2011)).
[113] Docket No. 09-035-23, Report and Order on Revenue Requirement, Cost of Service, and Spread of Rates at 27 (Feb. 18, 2010).

ICNU's adjustment also violates the Supremacy Clause of the United States Constitution and the filed rate doctrine. FERC has exclusive authority over the transmission and sale of electricity in interstate commerce under the Federal Power Act.[114] The United States Supreme Court had held that, by virtue of FERC's supremacy in this arena, "a state utility commission setting retail rates must allow, as reasonable operating expenses, costs incurred as a result of paying a FERC-determined wholesale price . . . Once FERC sets such a rate, a State may not conclude in setting retail rates that the FERC-approved wholesale rates are unreasonable."[115] States may not bar utilities "from passing through to retail consumers FERC-mandated wholesale rates."[116]

In addition, the filed rate doctrine prevents a state from modifying FERC-approved wholesale rates.[117] The filed rate doctrine requires that FERC-approved rates be given binding effect by states.[118] Ultimately, the Company is required by federal law to interconnect with wholesale transmission customers under the terms of the FERC-approved OATT. FERC's exclusive authority under the Federal Power Act over the terms of the OATT, as well as principles of federal preemption, preclude the Commission from disallowing the costs associated with this interconnection, including the costs of wind integration services.

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[114] 16 U.S.C. § 791 *et seq.*; *Nantahala Power & Light Co. v. Thornberg*, 476 U.S. 953, 963-64 (1986); *Cogeneration Ass'n of Cal. v. Fed. Energy Regulatory Comm'n*, 525 F.3d 1279, 1280 (D.C. App. 2008).
[115] *Nantahala*, 476 U.S. at 965-966.
[116] *Mississippi Power & Light Co. v. Mississippi*, 487 U.S. 354, 372 (1988).
[117] *Nantahala*, 487 U.S. at 966. The Company's OATT does not contain an explicit charge for wholesale wind integration rates, so imputing such a charge in PacifiCorp's rates would violate the filed rate doctrine and interfere with FERC's plenary authority over transmission rates in interstate commerce.
[118] *Nantahala*, 487 U.S. at 962.

E. Staff's and ICNU's Adjustments to the Company's Hydro Modeling Are Unreasonable.

Staff and ICNU object to the Company's modeling of forced hydro outages. Staff argues that certain "outlier" outage events should be removed from GRID modeling, resulting in a $1.34 million decrease in NPC.[119] ICNU argues that the Company's modeling of forced hydro outages does not take into consideration the Company's ability to reshape hydro resources and proposes to eliminate all hydro forced outages, reducing NPC by $2.1 million.[120] In addition, Staff argues that the impact of outlier events should be removed from the Company's modeling of planned outages, resulting in a reduction in NPC of $2.6 million.[121]

Both Staff and ICNU fail to present any evidence showing that the Company's modeled hydro generation in GRID is lower than the Company's actual operations. In fact, the normalized hydro generation in the Company's test period is 6.9 percent *higher* than the hydro generation for the last 10 years.[122]

As Staff acknowledged, the Company engaged in "detailed analysis" when modeling hydro forced outages.[123] Yet, Staff concluded that 67 percent of the outage days modeled by the Company were "outlier" events that should be excluded.[124] This conclusion is unsupported by any comparative analysis. Staff's determination of what constituted an "outlier" was apparently subjective and lacking in any evidentiary basis. It is also illogical to deem over two-thirds of the Company's forced outage days as "outliers," a term that implies that an outage is anomalous and unlikely to recur.

[119] Staff/100, Schue/23-24.
[120] ICNU/100, Deen/13, lines 8-11; ICNU/100, Deen/15, lines 2-3.
[121] Staff/100, Schue/25, lines 12-14.
[122] PAC/300, Duvall/25, lines 7-9.
[123] Staff/100, Schue/23, line 7.
[124] Staff/100, Schue/23, lines 14-18.

Staff concluded that all hydro outages in excess of 10 days were outliers.[125] Staff provides no supporting analysis demonstrating that outages in excess of 10 days are unusual for hydro facilities. In Docket UM 1355, the Commission concluded that for thermal plants, forced outages in excess of 28 days were outliers.[126] It reached this conclusion after the development of a robust evidentiary record that examined actual historical outage data and national data provided by utilities to the North American Electric Reliability Corporation.[127] Staff's conclusion was based on none of this type of comparative analysis.

Staff's analysis also contains errors. Staff incorrectly claims there are 1,120 outage days[128] in the Company's initial filing. In fact, Staff overstates outage days by 47 percent—there are 763 outage days in the Company's initial filing.[129] Staff arrived at the 1,120 number by incorrectly including outages at the Swift 2 facility that occurred outside the 48-month historical period, as well as outages at the East Side facility, which is no longer producing energy and was not included in the Company's filing.[130]

ICNU argues that forced outages should simply be removed from GRID runs, claiming that "in general terms"[131] the Company has "potential flexibility"[132] to respond to forced hydro outages by reshaping hydro output to take advantage of storage potential. Instead of quantifying its adjustment, however, ICNU simply removes all hydro forced outages, both capacity and energy, from the filing. In other words, ICNU's approach models

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[125] PAC/300, Duvall/26, n. 15.

[126] *In the Matter of Public Utility Commission of Oregon Investigation into Forecasting Forced Outage Rates for Electric Generating Units*, Docket No. UM 1355, Order No. 10-414 at 5 (October 22, 2010).

[127] Order No. 10-414.

[128] Staff/100, Schue/23, line 10.

[129] PAC/300, Duvall/26, line 7.

[130] PAC/300, Duvall/26, lines 7-19, n. 15. Staff filed an errata on July 11, 2012, correcting errors in its testimony, including the fact that the adjustment excluded all outages over 10 days, not 18 days as Staff originally stated.

[131] ICNU/100, Deen/13, lines 17-18.

[132] ICNU/100, Deen//13, line 23.

NPC as if no forced outages ever occurred.[133] Recalculating ICNU's adjustment to account only for the impact of additional energy generation reduces the adjustment by over one-third, from ICNU's proposed $2.1 million total company to $1.3 million. But even this amount is over-stated because it incorrectly assumes that there is never any lost generation due to hydro forced outages.[134]

Finally, Staff proposes an adjustment to the Company's modeling of planned outages at its hydro facilities, removing 57 percent of hydro planned outage days.[135] The basis of Staff's adjustment is an unsupported claim that these planned outages are outliers, which Staff concludes are any planned outages in excess of 28 days.[136] While Staff apparently relies upon the Commission decision in UM 1355 for this adjustment, that order established the methodology for calculating forced outages rates, not planned outages rates.[137] In addition, Staff's testimony provides no basis for excluding planned hydro outages in excess of 28 days. As the Company's evidence demonstrates, it is not unusual or anomalous for a planned outage at a hydro facility to exceed 28 days.[138]

Adopting Staff's adjustment would set a dangerous precedent arbitrarily limiting planned outages to a particular length and could result in decreased plant maintenance or more frequent forced outages.[139] Like Staff's forced outage adjustment, Staff's planned outage adjustment erroneously includes 606 outage days associated with the East Side and

[133] PAC/300, Duvall 27, lines 5-9.
[134] PAC/300, Duvall/27, lines 8-12.
[135] Staff/100, Schue/24-25.
[136] Staff/100, Schue/24, lines 7-9.
[137] Order No. 10-414 at 1.
[138] PAC/300, Duvall/28, lines 6-8.
[139] PAC/300, Duvall/28, lines 8-9.

West Side facilities (out of a total of 1,455 planned outage days included in Staff's adjustment)[140] even though these facilities are not included in the TAM.[141]

Staff's planned outage adjustment calls for using the Company's forecast outage schedule for purposes of modeling the planned outages in the TAM.[142] The Commission, however, adopted a stipulation authorizing PacifiCorp to use historical four-year averages to determine planned outage rates in Docket UM 1355.[143]

F. Noble Solutions' Proposed Adjustments to the Transition Credit Calculation Violate the TAM's Mandate Against Cost-Shifting Between Direct Access Customers and Cost-of-Service Customers.

Noble Solutions proposes several adjustments related to the calculation of Schedule 294 and Schedule 295 transition credits. First, Noble Solutions urges the Commission to extend the BPA transmission credit from the stipulation in the Company's 2012 TAM.[144] Second, Noble Solutions argues that the Commission should adopt the relaxed market caps from the stipulation in the Company's 2009 TAM.[145] Finally, Noble Solutions asks the Commission to increase the BPA transmission credit from \$0.75/MWh to \$1.422/MWh.[146]

Noble Solutions' proposals have a substantial impact on the transition adjustment. Combining the proposed BPA credit of \$1.42/MWh with the relaxation of market caps (a credit of approximately \$5.01/MWh) with the base transition credit produces a direct access transition credit of between \$12.43/MWh and \$12.92/MWh.[147] In other words, Noble Solutions' proposals effectively double the amount of the transition credit, shifting costs from direct access customers to cost-of-service customers.

[140] Staff/100, Schue/25, line 12.
[141] PAC/300, Duvall/28, lines 9-11.
[142] Staff/100, Schue/24, lines 10-13.
[143] Order No. 10-414, Appendix B at ¶ 6.
[144] Noble Solutions/100, Higgins/4, lines 1-2.
[145] Noble Solutions/100, Higgins/4, lines 12-16.
[146] Noble Solutions/100, Higgins/3, lines 22-23.
[147] PAC/300, Duvall/37, lines 8-16.

The Commission previously rejected a BPA transmission credit in Docket UM 1081. In that case, the Commission noted that the Company was contractually precluded from reselling its BPA transmission rights.[148] Noble Solutions claims that circumstances have changed because the Company may now resell its BPA transmission rights.[149] Noble Solutions fails to recognize that the Company's inability to sell BPA transmission rights was not the only factor influencing the Commission's decision to reject the BPA transmission credit. As noted in that case, even if the Company "could avoid a purchase as a result of direct access load loss, it could neither avoid purchasing transmission nor resell the freed up transmission to capture any value."[150]

Contrary to Noble Solutions' argument, the underlying circumstances for the Commission's rejection of the BPA transmission credit have not changed—the Company is still constrained in its ability to realize the value of the freed up transmission with BPA.[151] Compounding these constraints is the fact that the Company may actually need to acquire additional transmission to deliver freed-up generation to market in order to realize the transition credits determined for the lost loads; such credits are not reflected in the Company's calculation of the transition credit.

Noble Solutions adjustment for relaxation of market caps is also unreasonable. As previously explained, market caps are necessary to accurately forecast NPC in GRID. Any relaxation of market caps amounts to a subsidy to direct access customers and their suppliers, which conflicts directly with the TAM's purpose of avoiding cost shifting. In addition, Noble Solutions' adjustment rests on the premise that the wholesale market size will increase

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[148] *Investigation into Direct Access Issues for Industrial and Commercial Customers under SB 1149*, Docket No. UM 1081, Order No. 04-516 (Sept. 14, 2004).
[149] Noble Solutions/100, Higgins/12, lines 12-15.
[150] *See* Order No. 04-516 at 6.
[151] PAC/300, Duvall/35, lines 12-16.

when an electric service supplier wins the business of a retail customer. As previously shown, GRID currently overstates wholesale sales volumes, and Noble Solutions presents no evidence to show that increases to the size of the wholesale market due to direct access are exceeding the size of the market reflected in GRID. Finally, the market caps relaxation in the 2010 TAM assumes the market size increases by 25 MW because that is the size of the hypothetical block of power used to develop the transition credits. This exceeds the size of PacifiCorp's load that has elected direct access,[152] further undermining the reasonableness of Noble Solutions' market caps relaxation adjustment.

The Commission should reject Noble Solutions argument for extension of the BPA transmission credit negotiated in the Company's 2012 TAM and the relaxed market caps negotiated in the Company's 2009 TAM. Noble Solutions fails to acknowledge that both the BPA transmission credit and the relaxed market caps it advocates were approved by the Commission as part of non-precedential stipulations.[153] Noble Solutions alleges the Company has, "without any explanation or notice,"[154] changed its approach to the BPA transmission credit and market caps in the current TAM. However, Noble Solutions' argument for continuation of the BPA transmission credit and relaxed market caps is inconsistent with the underlying stipulations between Noble Solutions and the Company, which clearly limit the terms of the stipulations to a single proceeding.

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[152] PAC/300, Duvall/36, lines 6-10.

[153] For example, the stipulation in the 2012 TAM contains the following provision at paragraph 19:

> By entering into this Stipulation, no Party shall be deemed to have approved, admitted, or consented to the facts, principles, methods, or theories employed by any other Party in arriving at the terms of this Stipulation, other than as specifically identified in the body of this Stipulation. No Party shall be deemed to have agreed that any provision of this Stipulation is appropriate for resolving issues in any other proceeding, except as specifically identified in this Stipulation.

[154] Noble Solutions/100, Higgins/8, lines 18-19.

G. The Commission Should Reject ICNU's Request that PacifiCorp Use a Different Power Supply Model.

ICNU argues that the Commission should require the Company to use a NPC dispatch model developed by an independent third-party vendor.[155] ICNU specifically recommends the AURORA model used by Avista and Puget Sound Energy in Washington, but allows that the ultimate decision of which independent model to use should lie with the Company.[156] No other party addresses this issue.

ICNU's argument centers on claims that the Company's internally-developed GRID model is complex, controversial, and time-consuming to review. But ICNU provides no evidence that an independently developed model will address these concerns. The GRID model is the most reasonable tool available to determine the Company's NPC because it was developed by the Company and therefore reflects the Company's unique power system in a manner that cannot be replicated by a third-party model. GRID has been used in rate cases and numerous other regulatory filings in six states for over a decade. While no model is perfect, the GRID model is a reasonable and responsive tool that should not be eliminated based on speculation that another model may prove simpler, less controversial, or less time-consuming.

IV. CONCLUSION

For the reasons set forth above, PacifiCorp respectfully requests that the Commission approve PacifiCorp's 2013 TAM and allow a rate increase of $3.4 million, subject to the TAM Final Update on November 15, 2012. The purpose of this filing is to forecast the Company's 2013 NPC as accurately as possible. The Commission can accomplish this by approving the Company's overall NPC forecast as reasonable and rejecting proposed

[155] ICNU/100, Deen/17, lines 4-6.
[156] ICNU/100, Deen/18, lines 24 –19, lines 1-2; ICNU/100, Deen/19, lines 12-13.

modeling adjustments to market caps, arbitrage and trading, hydro outages, third-party wind integration and the calculation of the transition adjustment.

Respectfully submitted this 6th day of August 2012,

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CERTIFICATE OF SERVICE

I hereby certify that on this 6th of August, 2012, I caused to be served, via E-mail, a true and correct copy of the foregoing document on the following named person(s) at his or her last-known address(es) indicated below.

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