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A DIVISION OF PACIFICORP

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August 3, 2015

VIA ELECTRONIC FILING
AND OVERNIGHT DELIVERY

Public Utility Commission of Oregon
201 High Street SE, Suite 100
Salem, OR 97301-1166

Attn: Filing Center

Re: UE 296 – Reply Testimony and Exhibits

PacifiCorp d/b/a Pacific Power hereby submits for filing the Reply Testimony and Exhibits of Brian S. Dickman, Frank C. Graves, Stephen A Larsen, and Judith M. Ridenour. Included with this filing is a CD containing the electronic workpapers.

PacifiCorp respectfully requests that all data requests regarding this matter be addressed to:

By e-mail (preferred): datarequest@pacificorp.com

By regular mail: Data Request Response Center
PacifiCorp
825 NE Multnomah, Suite 2000
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Please direct informal correspondence and questions regarding this filing to Erin Apperson, Manager, Regulatory Affairs, at (503) 813-6642.

Confidential material in support of the filing has been provided to parties under the protective order in this docket (Order No. 10-069).

Sincerely,

R. Bryce Dalley / EAA

R. Bryce Dalley
Vice President, Regulation

Enclosures

CERTIFICATE OF SERVICE

I certify that I served a true and correct copy of PacifiCorp's Reply Testimony for the 2016 Transition Adjustment Mechanism on the parties listed below via e-mail and/or overnight delivery in compliance with OAR 860-001-0180.

UE 296

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Dated this 3rd day of August 2015.

Carrie Meyer
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Docket No. UE 296
Exhibit PAC/500
Witness: Brian S. Dickman

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

REDACTED
Reply Testimony of Brian S. Dickman

August 2015

REPLY TESTIMONY OF BRIAN S. DICKMAN

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Attached Exhibits

Q. Are you the same Brian S. Dickman who previously submitted direct testimony in this proceeding on behalf of PacifiCorp d/b/a Pacific Power (PacifiCorp or the Company)?

A. Yes.

PURPOSE AND SUMMARY OF TESTIMONY

Q. What is the purpose of your reply testimony?

A. My testimony has two parts: a Transition Adjustment Mechanism (TAM) update section (Reply Update), consistent with the TAM Guidelines adopted by the Commission in Order No. 09-274 and revised in Order Nos. 09-432 and 10-363, and a reply section responding to the parties' proposed adjustments.

In the Reply Update, I explain the reasonableness of the Company's revised Oregon net power costs (NPC) of $375.2 million for the test period of the 12 months ending December 31, 2016 (unless otherwise specified, references to NPC throughout my testimony are expressed on an Oregon-allocated basis). I also provide corrections and contract, fuel, and forward price curve updates to the Company's April 1, 2015, filing (Initial Filing).

In my reply testimony, I respond to the adjustments to the Company's NPC presented by Mr. Jorge Ordonez on behalf of the Public Utility Commission of Oregon Staff (Staff), Mr. Bob Jenks and Ms. Nadine Hanhan of the Citizens' Utility Board of Oregon (CUB), Mr. Bradley Mullins on behalf of the Industrial Customers of Northwest Utilities (ICNU), and Mr. Kevin Higgins on behalf of Noble Americas Energy Solutions LLC (Noble Solutions).

Q. Please identify the other witnesses providing reply testimony supporting the 2016 TAM.

A. There are three other witnesses providing reply testimony in support of the Company's 2016 TAM filing: Stephen A. Larsen, Frank C. Graves and Judith M. Ridenour. These witnesses all provided direct testimony in this case.

Q. Please provide a summary of your reply testimony.

A. The goal of the TAM is to forecast the actual NPC the Company expects to incur during the test period as accurately as possible. The complexity of the Company's multi-state power supply system presents NPC modeling challenges, which have resulted in systematic under forecasts of NPC in the TAM. To better forecast the Company's NPC, the Company has presented several modeling refinements in the 2016 TAM filing. My testimony is largely focused on responding to the parties' challenges to these refinements.

The Company's proposed approach to modeling system balancing transactions reflects the significant actual costs related to the timing and volume of these purchases and sales compared to a GRID model result that does not capture such costs. The Company's approach is conceptually similar to modeling adjustments made by Portland General Electric Company (PGE) and Idaho Power Company (Idaho Power), and nothing raised in the parties' testimony supports its rejection:

- Staff acknowledges the rationale behind the Company's proposal, but argues for more time to review the modeling. While a proposal designed to model system balancing costs on a more granular, real-time basis will necessarily present some complexities, it is undisputed that the Company has provided robust analytical support and detailed explanations of its proposal. This supports the adoption of the modeling change in this case, not its deferral to a future case.
- CUB claims that the Company's proposal is a departure from normalized

ratemaking. But the proposal relies on many of the same principles used without controversy to establish normalized rates, such as historical rolling averages.

- ICNU's criticisms of the Company's proposal rely on ICNU's fundamental misunderstanding of market dynamics and mischaracterizations of the intent and mechanics of the proposal. ICNU fails to present a single persuasive argument in opposition to the *actual* proposal.

- ICNU also proposes its own adjustment ostensibly intended to address the same issues as the Company's proposal. But ICNU's recommendation has nothing to do with the Company's proposal and addresses an entirely unrelated issue. ICNU's adjustment would exacerbate the Company's under forecasting and departs, without explanation, from recent Commission orders rejecting similar ICNU adjustments.

Next, the Company's modeling of its regulation reserves, together with adjustments accepted in this testimony, fully reflect the reserve benefits resulting from the Company's participation in the Energy Imbalance Market (EIM). The Company's modeling also more accurately models regulation reserves on an hourly basis, rather than using flat monthly amounts.

- Staff proposed an adjustment that would reduce the regulation reserve requirement to account for scheduling of load and wind on a within-hour basis through the EIM. This adjustment incorrectly assumes that the EIM will allow the Company to participate in a within-hour balancing market.

- ICNU proposes three adjustments. ICNU's first adjustment is based on the application of an outdated reliability metric that no longer applies to the Company and, if implemented, would result in the Company failing to hold sufficient reserves. ICNU's second adjustment fails to account for how interruptible loads are used to meet the Company's reserve obligations. ICNU's third adjustment, which is joined by Staff, incorrectly assumes that the Company can dynamically transfer reserves between its balancing areas under the EIM.

To fully capture the benefits of the EIM for Oregon customers, the Company's reply filing makes updates and changes to its modeling of EIM benefits: First, the Company updated the data used to model these EIM benefits to include historical results through June 2015. Second, to address ICNU's and CUB's concerns regarding seasonality, the Company proposed a modeling adjustment and a further update to cover the summer months in the final TAM update. Third, the Company adjusted its EIM benefits modeling to incorporate the future EIM participation of NV Energy, Puget Sound Energy (PSE) and Arizona Public Service (APS). With these updates and changes, the Company has accurately reflected the benefits of EIM participation for the 2016 test period.

ICNU makes several other NPC adjustments. ICNU argues that the Company was imprudent to not renew the Hermiston generation contract, leaving it with transmission capacity that is no longer used and useful. But ICNU's adjustment is entirely speculative, assumes a fundamental flaw in the Company's resource planning modeling that the Commission has never identified, and lacks evidentiary support.

ICNU also challenges the Company's proposed refinements to its modeling of forced outages and wind generation capacity. ICNU rejects the Company's proposals without actually disputing the Company's evidence that the modeling changes will produce a more accurate forecast than ICNU's recommendation to continue the status quo. ICNU also fails to cite to or reconcile contrary Commission precedent.

Noble Solutions recommends that the transition adjustment reflect the value of freed-up renewable energy certificates (RECs) resulting from the departure of direct access load. This argument is a variation on Noble Solutions' argument for a transmission credit in the transition adjustment, an argument that the Commission has repeatedly rejected. In addition, Noble Solutions' recommended adjustment to the opt-out charge in the Company's five-year direct access program is directly contrary to the Commission's recent orders in docket UE 267.

REPLY UPDATE

Introduction

Q. In the Initial Filing, the Company requested NPC of $374.5 million for the test period ending December 31, 2016. How has your NPC recommendation changed?

A. Test period NPC increased from $374.5 million to $375.2 million, a $0.7 million increase from the Initial Filing. On a total company basis, NPC decreased by $965,476, from $1.538 billion to $1.537 billion.

Exhibit PAC/501 shows that the Company's Reply Update proposes a rate increase of $12.4 million or 1.0 percent overall. The results of the Company's updated NPC study are provided in Exhibit PAC/502. A list of all corrections and updates made, along with the approximate impact of each on NPC, is provided in Exhibit PAC/503. Exhibits PAC/504, PAC/505, and PAC/506 present updated information for Other Revenue, EIM Costs, and EIM benefits, respectively, as contained in the Company's Reply Update.

Q. Please explain the changes reflected in your revised NPC request.

A. First, the Company made corrections to the Initial Filing and updated the Company's proposed NPC with: (1) the most recent official forward price curve and short-term firm transactions; (2) new power, fuel, and transportation/transmission contracts and updates to existing contracts, including the Commission-approved contract for Bridger Coal Company's purchase of longwall equipment from the Deer Creek mine;[1] and (3) updated EIM operational experience (adjusted for seasonality) and benefits associated with new EIM participants (NV Energy, PSE and APS). Second, the Company accepted ICNU's proposed adjustment to the Company's flexibility reserve benefits associated with the participation of PSE and APS in the EIM, starting in October 2016.

Q. Is the Company's revised NPC recommendation in this case reasonable?

A. Yes. The Reply Update reflects the most recent information available to the Company in the determination of 2016 NPC and sets a reasonable and realistic NPC baseline for 2016.

Q. Is it important to set the most accurate NPC forecast possible to meet the Commission's goals for the TAM and the Company's power cost adjustment mechanism (PCAM)?

A. Yes. As stated by the Commission, the purpose of the TAM is to capture costs associated with direct access and prevent unwarranted cost shifting.[2] The TAM transition adjustment is calculated by comparing the value of energy used to serve direct access loads with the cost of service rate under the customers' specific energy-only tariff. The Commission approved an annual NPC update to ensure that both the value of freed-up energy and the cost of service rate are calculated for the same period using the same data. In addition, under PacifiCorp's PCAM, rates may be adjusted in 2017 to address differences between the 2016 TAM NPC baseline determined in this case and actual 2016 NPC. The more accurate the NPC forecast is

[1] *Re PacifiCorp Application for an Order Authorizing the Transfer of Mining Equipment and Approval of an Affiliated Transaction with Bridger Coal Company*, Docket Nos. UP 328 & UI 357, Order No. 15-218, App. A at 7 (July 21, 2015).

[2] *In the Matter of Pacific Power & Light Company, d/b/a PacifiCorp Request for a General Rate Increase*, Docket No. UE 170, Order No. 05-1050 at 21 (Sept. 28, 2005).

in this case, the less likely it is that the Company will need to adjust rates through a PCAM surcharge or surcredit in 2017.

NPC Corrections and Updates

Q. Did the Company previously provide the parties a list of known corrections and updates?

A. Yes. Under the TAM Guidelines, on June 8, 2015, the Company provided a list of known corrections and updates. The current filing incorporates those corrections and updates along with several additional updates identified since then. The individual corrections and updates and their impact on NPC are identified in Exhibit PAC/503.

Q. Please summarize the major changes in NPC resulting from the update.

A. Table 1 illustrates the change in NPC by category compared to the NPC originally filed in this case.

Table 1
Net Power Cost Reconciliation

($ millions)	Total Company	Oregon Allocated
OR TAM 2016	**$1,537.6**	**$374.5**
Increase/(Decrease) to NPC:		
Wholesale Sales Revenue	$26.5	$6.8
Purchased Power Expense	-$1.7	-$0.4
Coal Fuel Expense	-$12.3	-$3.0
Natural Gas Fuel Expense	-$14.1	-$3.4
Wheeling and Other Expense	$0.6	$0.1
Total Increase/(Decrease) to NPC	**-$1.0**	**$0.1**
Oregon Situs Solar		$0.6
OR TAM 2016 Reply Update	**$1,536.7**	**$375.2**

The changes in the components of NPC from the Initial Filing are largely driven by a decrease in the forward market prices for electricity and natural gas. While lower electricity prices reduce wholesale sales revenues, this effect is largely offset by reductions in purchased power, coal fuel expense, and natural gas fuel expense. Finally, wheeling expense is slightly higher as a result of wheeling rate updates.

Q. **Please identify the corrections that were included in the Company's updated NPC.**

A. Three corrections to the filed NPC have been identified since the case was filed and each has been incorporated into the Company's Reply Update.

- **Demand-Side Management (DSM) Cool Keeper Reserve—**The reserves associated with the Company's Cool Keeper interruptible load program were mistakenly excluded. This correction reduces total company NPC by approximately $100,000.

- **Regulation Reserve Requirement—**The regulation reserve requirement associated with incremental wind generation was overstated. Correcting this input decreases total company NPC approximately $473,000.
- **Utah Red Hills Qualifying Facility (QF) Contract Price—**The Utah Red Hills QF is expected to achieve commercial operation, as defined in the contract, on December 1, 2016. Pricing for the month of December has been corrected to reflect the contract price, rather than the market-based index applicable prior to commercial operation. This correction increases total company NPC by approximately $176,000.

Q. Please explain the updates that are included in the Company's Reply Update.

A. The Company's Reply Update includes the following specific updates:

- **New QF Contracts—**The Company has executed QF contracts for the output of four new large solar projects (Granite Mountain East, Granite Mountain West, Iron Springs, Pavant II) and 17 small Oregon solar projects. The Company also adjusted the start date of four small Oregon solar projects already reflected in the direct testimony to match the scheduled commercial operation date defined in the contracts. The Company has also executed a new QF contract for the output of BYU Idaho's new cogeneration facility. Finally, the Company has executed four QF contracts with existing hydro facilities including Yakima Tieton's Cowiche and Orchard projects in Washington, and the Loyd Fery, and Roush projects in Oregon. This update increases total company NPC by approximately $4.3 million.

- **Eagle Mountain Purchase—**The Company's acquisition of the assets and service territory from the City of Eagle Mountain included the assumption of Eagle Mountain's existing power purchase agreements. Only the fair market value of the power purchase agreements as of the date of closing is included in NPC. This update increases total company NPC by approximately $52,000.
- **QF Contract Status—**The Company has terminated the Champlin Blue Mountain Wind QF contract effective May 14, 2015, due to failure to provide default security, and the contract has been removed from NPC. This update decreases total company NPC by approximately $2.3 million.
- **Pipeline Expenses—**Pursuant to its tariff, Questar Gas Company recently began applying a demand charge for Lake Side 1's gas supply. Northwest Pipeline provided an updated cost of service calculation for the Chehalis Pipeline Lateral, with a new monthly payment effective April 2015. These updates increase total company NPC by approximately $1.5 million.
- **Biomass One QF Non-Generation Agreement—**The Company has executed a non-generation agreement with the Biomass One QF effective during May and June 2016. This update increases total company NPC by approximately $19,000.
- **Official Forward Price Curve and Short-Term Firm Transactions—**The Company updated the official forward price curve from December 31, 2014, to June 30, 2015. On average, market prices for electricity at the Mid-Columbia and Palo Verde markets decreased by approximately 6.6 percent. Similarly, market prices for natural gas decreased, on average, approximately

11.1 percent. Short term sales and purchase transactions for electricity and natural gas were also updated through July 1, 2015. This update increases total company NPC by approximately $142,000.

- **Douglas Public Utility District Pro-forma—**This update incorporates the fiscal year September 1, 2015, through August 31, 2016, preliminary pro-forma published by the Douglas Public Utility District on May 1, 2015. This update decreases total company NPC by approximately $75,000.
- **Black Hills Sale Fixed and Variable Charges—**This update reflects the annual update of the fixed and variable charges for the sales contract with Black Hills Corporation. This update decreases total company NPC by approximately $329,000.
- **PGE Cove Annual Cost—**The annual purchase power expense for PGE Cove has been updated to reflect the latest projection by PGE. This update decreases total company NPC by approximately $80,000.
- **Open Access Transmission Tariff Rates—**Idaho Power, APS, Bonneville Power Administration (BPA), and Platte River Power Authority have filed updated tariff rates effective during 2016. These updates increase total company NPC by approximately $909,000.
- **Goodnoe Hills Wheeling Interconnection Credit—**The Company has entered an agreement to receive BPA wheeling credits associated with the Goodnoe Hills interconnection costs. This update reduces total company NPC by approximately $540,000.

- **Coal Costs—**Coal costs were updated to reflect changes in prices and volumes. Company witness Stephen Larsen provides additional detail on the update in his reply testimony. The updated costs decrease total company NPC by approximately $1.8 million from the Initial Filing.
- **EIM Operational Experience—**The Company's Initial Filing reflected EIM results from December 2014 and January 2015. NPC inputs based on EIM results included the average EIM export margin and flexibility reserve diversity benefit per megawatt of available transmission capability, as well as the monthly EIM import margin. This update incorporates EIM results from December 2014 through June 2015, and adjusts them for seasonality by utilizing the higher level of EIM benefits from the June results in the months of June through September in the forecast period. This adjustment decreases total company NPC by approximately $814,000. In addition, the Company has updated NPC to reflect the benefits associated with new EIM participants. The Company's Reply Update incorporates additional inter-regional benefits from NV Energy, PSE, and APS participation in the EIM which decrease total company NPC by approximately $1.6 million.
- **EIM Regulation Reserve Benefit**—Recent Federal Energy Regulatory Commission (FERC) filings have indicated that NV Energy will be directly interconnected to the Company's east Balancing Authority Area (BAA), rather than indirectly via the Company's dynamic rights from the Company's west BAA to the California Independent System Operator Corporation (CAISO). As such, basing the Company's reserve savings from NV Energy's

participation on the southbound California-Oregon Intertie (COI) transmission available for the EIM is no longer necessary. The Company's reserve savings increase by six MW as a result of this change. This update results in a decrease in total company NPC of $323,000.

UNCONTESTED ADJUSTMENT

Flexibility Reserve Benefits for New EIM Participants

Q. Please describe ICNU's recommended adjustment to incorporate flexibility reserve benefits associated with new participants to the EIM.

A. ICNU proposes that the flexibility reserve benefits associated with the participation of PSE and APS in the EIM be included starting in October 2016. The Company does not oppose this adjustment.

Q. How did the Company model the accepted adjustment?

A. As proposed by ICNU, the Company has incorporated a reserve savings of 16 MW in its Reply Update to reflect PSE and APS participation in the EIM beginning October 2016. Incorporating this adjustment in the Company's Initial Filing produces a benefit of approximately $213,000 on a total company basis. The impact calculated by the Company is larger than that proposed by ICNU because ICNU's calculation was based on the very low regulating reserve levels resulting from its separate "Reliability Metric" adjustment. Because so few reserves are included in ICNU's NPC studies, the additional savings from EIM-related reserve reductions were relatively small.

REPLY TESTIMONY

Improved Modeling of Day-Ahead and Real-Time Balancing Transactions

Introduction

Q. Please briefly summarize the Company's proposal in this case to more accurately model day-ahead and real-time system balancing transactions.

A. The Company's NPC reflects important changes to modeling market transactions, defined as non-hedging, system balancing transactions. PacifiCorp developed these modeling refinements to more accurately capture the true cost of balancing its system in the short-term markets.

The Company's system balancing proposal has two components: volumes selected by the GRID model, which includes adjusted prices for purchases and sales and additional volumes which reflect the fact that GRID determines a single transaction volume for each hour, whereas the Company must balance its system with a combination of monthly, daily, and hourly products. For the adjusted prices in GRID, the Company uses the historical differences between the average market prices over each month and actual prices for the Company's day-ahead and real-time balancing transactions in that month for both purchases and sales. This adjustment creates a more accurate forecast of market prices used for system balancing in the GRID model. Previously, GRID model forecasts only included monthly average prices, and the same prices were used for purchases and sales.[3] The pricing component increases the Company's NPC by $4.3 million.

[3] Wholesale market prices for the system balancing transactions in GRID are based on an hourly forward price curve that is developed from monthly heavy-load-hour (HLH) and light-load-hour (LLH) prices with hourly scalars applied. These scalars are identical within a given month for each weekday of that month. The prices are input into the model and do not change based on the volume of the system balancing transactions.

For the additional volume, the Company calculates the system balancing volume which reflects the operational practice of transacting on a monthly basis using standard 25 MW block products, rebalancing on a daily basis using standard 25 MW block products, and finally closing the remaining position on an hourly basis in real-time markets. As designed, the GRID model perfectly balances each hour to the fraction of a megawatt and does not simulate transacting in the market for standard products. The result of the Company's adjustment is to include additional monthly, daily, and hourly transactions, in the form of offsetting sales and purchases representing this balancing process. The Company calculates these volumes outside of the GRID model and prices them to cover the Company's historical average system balancing costs not already captured by the GRID model results. The additional volume component increases the Company's total Company NPC by $3.7 million.

Q. Why did the Company propose these modeling changes?

A. The Company's historical experience demonstrates that it incurs significant expense in the day-ahead and real-time markets to balance its system. As I explain in my direct testimony,[4] the reason that the Company incurs a net expense for these balancing transactions is timing: the Company is generally buying during periods when prices are high and selling during periods when prices are low. This issue is illustrated in Confidential Figure 1 below, which shows actual HLH prices at the Mid-Columbia (Mid-C) market hub during September 2013, along with the actual volume of the Company's Mid-C purchase and sale transactions that month. The

[4] PAC/100, Dickman/27-28.

average HLH market price that month was $38 per megawatt-hour (MWh), but during the month the Company paid an average of $43/MWh when it made market purchases and received an average of $29/MWh when it made market sales.

Confidential Figure 1

[redacted]

Without the Company's proposed modeling refinements, the flat average market price in its GRID NPC forecast results in average Mid-C prices in September 2016 of $37/MWh for purchases and $35/MWh for sales, compared with a market price of $36/MWh. This price difference is much lower than historical levels. The Company's proposal is intended to more accurately match the purchased power costs and sales revenues in the NPC forecast with actual historical experience.

Q. Has the Commission previously invited parties to more closely review how short-term transactions are modeled in the Company's NPC?

A. Yes. In the 2008 TAM, Staff proposed a margin adjustment, which imputed additional short-term transactions into the Company's NPC based on historical transaction levels and assigned a net margin to these transactions. The Commission rejected this adjustment, in part, in Order No. 07-446, concluding that there was no evidence of a net margin on system balancing transactions.[5] But, the Commission added: "We invite the parties to look more closely at the GRID model to examine whether there is a systematic bias in the way it treats short-term wholesale energy transactions, both for system balancing and for arbitrage and trading."[6]

The Company's proposal in this case is based on historical evidence of the Company's system balancing costs, costs which the GRID model does not reflect absent the adjustments proposed by the Company. This systematic understatement of actual costs has contributed to the Company's under recovery of NPC in Oregon. The Company's under recovery of Oregon-Allocated NPC increased from $33 million (or 8.81 percent) in 2013 to $36 million (or 9.56 percent) in 2014, supporting the need for the Company's proposed NPC modeling improvements.

Q. Has the Commission encouraged PacifiCorp to continue to refine its NPC modeling to improve the accuracy of its NPC forecast?

A. Yes, in the 2013 TAM, the Commission specifically directed PacifiCorp "to refine its

[5] *In the Matter of PacifiCorp, d/b/a Pacific Power 2008 Transition Adjustment Mechanism*, Docket No. UE 191, Order No. 07-446 at 10-11 (Oct. 17, 2007). The Commission accepted the adjustment as it related to arbitrage transactions, which the Commission concluded earned a margin. In the Company's 2013 TAM, the Commission removed the arbitrage adjustment after concluding that the Company's revisions to GRID's topology now captured the arbitrage transactions in the model. *In the Matter of PacifiCorp d/b/a Pacific Power 2013 Transition Adjustment Mechanism*, Docket No. UE 245, Order No. 12-409 at 9 (Oct. 29, 2012).
[6] *Id.* at 11.

modeling to produce the best possible estimates of all components of net power costs."[7]

Q. Can you provide recent examples where the Commission has approved the Company's NPC modeling changes that, as here, use historical data to improve the accuracy of the NPC forecast?

A. Yes. In the 2012 TAM, the Commission approved a proposal for more realistic pricing of purchase and sales transactions with hourly scalars derived from historical data.[8] The Commission rejected ICNU's argument for the use of less granular scalars, explaining that "a key purpose of the GRID model is to determine the economic dispatch of Pacific Power's resources on an hourly basis," and the "use of hourly scalars is intended to develop results consistent with historical price data."[9]

In the 2014 TAM, the Commission approved a proposal to shape hourly wind profiles based on historical data, stating that: "We agree with Pacific Power that improving the granularity of its modeling by including actual hourly variation will represent a superior forecasting of the dispatch value of wind output than the flat blocks the company has used in previous TAM dockets."[10]

Q. In both of these cases, did parties object to the Company's proposals because they relied on historical data and added complexity to NPC modeling?

A. Yes. In the 2012 TAM, ICNU asked the Commission to reject the use of hourly scalars because, among other things, they were "overly complex" and unnecessarily

[7] *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).
[8] *In the Matter of PacifiCorp d/b/a/ Pacific Power 2012 Transition Adjustment Mechanism*, Docket No. UE 227, Order No. 11-435 (Nov. 4, 2011).
[9] *Id.* at 23.
[10] *In the Matter of PacifiCorp d/b/a Pacific Power 2014 Transition Adjustment Mechanism*, Docket No. UE 264, Order No. 13-387 at 4 (Oct. 28, 2013).

detailed. Similarly, in the 2014 TAM, Staff and CUB argued that consideration of the wind shaping proposal should be deferred to allow time for additional workshops and review. In both cases, the Commission adopted the Company's proposals, weighing the benefits of improved NPC forecast accuracy over concerns about increased modeling complexity.

Q. Do parties support the Company's proposal in this case?

A. No, the parties object to the Company's approach to modeling system balancing transactions. Staff and CUB propose to revert to the Company's previous modeling, reducing the 2016 TAM by approximately $8 million. ICNU proposes two different adjustments. First, ICNU proposes to remove market caps from the Company's proposal, reducing NPC by approximately $1.6 million. Second, ICNU proposes an entirely new approach that would both eliminate market caps in GRID and apply a $0.50/MWh bid-ask spread to the price of balancing transactions. This adjustment reduces NPC by $9.4 million.

Q. Do any of the parties challenge how the Company has calculated its historical balancing expense or the fact that the timing of purchase and sale transactions can influence their price?

A. No. None of the parties contest how the Company calculated its historical system balancing expense (*i.e.*, the historical difference between total purchases and sales), nor do parties argue that the Company will not incur the same type of expense in the future. ICNU explicitly states that the expected average purchase and sale prices will differ based on timing within a month.[11] And, as discussed below, Staff recognizes

[11] ICNU/100, Mullins/16, lines 15-23.

the impact that timing can have on spot sales and purchases.[12]

Response to Staff's Position on Company's System Balancing Proposal

Q. Please explain Staff's position on the Company's system balancing proposal.

A. Staff agrees with the rationale for both the price and volume components of the Company's proposal. Specifically, Staff supports modeling NPC to reflect the fact that the Company balances its system with 25 MW blocks, creating additional purchase and sales volumes as these blocks are applied to actual real-time and day-ahead imbalances.[13] Staff also agrees that there is a need to address the fact that electricity pricing variations are not captured in the forward price curve.[14]

Staff does not support the Company's adjustment at this time, however, because of its complexity and the challenges Staff experienced in reviewing the Company's voluminous and technical workpapers.[15] Instead, Staff recommends that the Company conduct workshops before the 2017 TAM to allow the parties to better understand the adjustment for potential inclusion in that filing.

Q. How do you respond to Staff's position?

A. The Company appreciates Staff's fundamental agreement with the Company's rationale for its modeling changes. The Company also understands Staff's concerns regarding the complexity of these modeling changes, but does not agree that the comprehensiveness of the Company's analysis justifies delaying implementation of the changes.

[12] Staff/100, Ordonez/23, lines 16-17.
[13] Staff/100, Ordonez/19.
[14] Staff/100, Ordonez/23.
[15] Staff/100, Ordonez/23-24.

The Company took seriously its obligation to substantiate its system balancing proposal. Because the Company operates a diverse and wide-ranging system and the GRID model reflects purchase and sale opportunities at multiple major markets, the Company's workpapers are inevitably detailed and voluminous.

Q. Has the Company worked with the parties to assist their understanding of the Company's proposal and workpapers?

A. Yes. As Staff acknowledges, the Company has worked extensively with the parties to assist them in understanding the Company's proposal and navigating its workpapers.[16] The Company has also prepared a condensed version of its workpapers and recently provided it to parties as a supplemental data request.[17]

Q. Can you provide a simplified example of how the Company's adjustment will work using a hypothetical month?

A. Yes. Exhibit PAC/507 contains an example showing the operation of the Company's proposal. The exhibit highlights the following key steps which are performed separately for purchases and sales. First, the average price of the Company's actual real-time and day-ahead transactions is calculated using historical data. Second, the average realized price is compared to the average market price for that month, and the difference is multiplied by the total historical volume (including transactions that may later be booked-out) to calculate the net cost versus if the transactions had been done at the average market price. Third, the difference in cost is divided by the average historical volume to calculate the price adder for each month. Fourth, the price adder is used to adjust prices in the GRID model and the model is allowed to simulate

[16] Staff/100, Ordonez/23.
[17] *See* PacifiCorp's first supplemental response to OPUC 37.

system dispatch including system balancing sales and purchases. Fifth, the net cost of the modeled system balancing transactions is subtracted from the net historical cost and the balance is applied as a cost adjustment for the additional volumes added to NPC to reflect the standard block transactions used to balance the Company's position. In this way, the Company's net system balancing transaction costs are adjusted to equal the Company's three-year average.

Response to CUB's Position on Company's System Balancing Proposal

Q. What are CUB's concerns regarding the system balancing proposal?

A. CUB argues that the system balancing proposal is a departure from weather normalized power cost forecasting and should be rejected.[18] CUB claims that the "TAM is not designed to forecast actual power costs—it is designed to dispatch PacifiCorp's system in a weather normalized manner to establish a forecast of power cost."[19] Thus, CUB concludes that the TAM is "not expected to accurately account for actual costs."[20] CUB contends that reflecting actual costs in the TAM shifts risk that the design of the PCAM assigns to the Company.

Q. How do you respond to CUB's concerns?

A. I disagree with CUB's argument that the system balancing proposal is inconsistent with the Company's normalization of NPC. On the contrary, intra-month variations in weather are normal and reflected in the Company's proposed NPC. 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

[18] CUB/100, Jenks-Hanhan/5-7.
[19] CUB/100, Jenks-Hanhan/5-6.
[20] CUB/100, Jenks-Hanhan/6.

variation of its purchase and sale prices around that higher than normal average price. In addition, the proposal uses a multi-year rolling average, a common tool in preparing inputs to a normalized NPC forecast.

Second, CUB's position implies that the TAM should not be refined to most accurately forecast actual power costs. This is contrary to recent Commission precedent cited above. It is also inappropriate to exclude costs that have occurred historically and are expected to occur during the forecast period. Absent the Company's proposal, the expense resulting from system balancing will continue to be systematically excluded from forecast NPC.

Q. Is CUB's position consistent here with its position in other dockets?

A. No. As described below, CUB agreed that it is reasonable for Idaho Power to make a conceptually similar adjustment outside of its power cost model. Thus, CUB's argument here that the system balancing costs are "part of the normal business risk that falls into the PCAM deadband"[21] is inconsistent with CUB's position with respect to Idaho Power.

Response to ICNU's Position on Company's System Balancing Proposal

Q. What are the primary objections raised by ICNU with regard to the Company's system balancing proposal?

A. ICNU has six criticisms of the Company's proposal: (1) the proposal results in a level of sales and purchases that does not correspond to historical levels; (2) a utility should fair no better or worse transacting in forward markets versus spot markets; (3) the identified system balancing costs are concerned with hedging contracts and thus

[21] CUB/100, Jenks-Hanhan/7.

incorporate historical losses between the forward period and the prompt period; (4) the Company's proposal has no bearing on the bid-ask spreads at which the Company can buy and sell in the market; (5) no other Northwest utilities make adjustments external to their models to compensate for these types of costs; and (6) the Company has already incorporated a day-ahead system balancing charge in its forecast to account for these costs. As I discuss below, none of these claims have merit.

Q. Please describe ICNU's objection regarding the transaction volume component of the Company's proposal.

A. ICNU claims that the Company's proposal would result in a level of sales and purchases that overstate the levels of historical transactions.[22] ICNU further argues that the Company's position in this case contradicts the Company's position in docket UE 245, the 2013 TAM, where the Company claimed that GRID over forecasts short-term firm sales transactions.

Q. Citing to your direct testimony at page 29, lines 12-19, ICNU states that the "Company alleged that the GRID model under-forecasts the level of sales and purchases relative to the amount made in actual operation, including forward hedging contracts." Is this an accurate summary of your testimony?

A. No, these are ICNU's words and characterizations, not mine. My testimony addressed the need to account for the incremental, offsetting balancing volumes associated with the use of standard 25 MW products to balance the Company's open position. I did not discuss whether GRID systematically under forecasts transaction levels or forward hedging contracts.

[22] ICNU/100, Mullins/12-13.

Q. Why does ICNU contend that the Company's proposal would result in volumes above historical levels?

A. ICNU's analysis in ICNU's Confidential Figure 1[23] compares the transaction volumes under the Company's proposal—which includes the additional balancing transactions added outside the GRID model—with the volumes in the Company's actual NPC reports. ICNU's comparison is inaccurate, though, because it does not adjust for the fact that, for accounting purposes, transactions that are equal and offsetting in terms of volume, delivery period, and location, are "booked out" or netted together. The effect of netting out this bookout transaction volume is to report a reduced volume of both purchases and sales, with no impact on the net cost of such transactions. While ICNU shows that the Company's proposal includes more transactions than historical levels, this is solely a function of ICNU omitting bookout transaction volume from historical levels.

Q. Why do bookouts occur?

A. Bookouts occur when a utility has offsetting purchase and sale transactions for the same delivery period and at the same location. The Financial Accounting Standards Board (FASB) has specific rules that govern netting of such transactions for accounting purposes. When two transactions are booked out, the underlying energy does not physically flow, but the net financial impact remains on the Company's books.

Much of the Company's transaction volume is monthly and daily block products, which do not precisely match the Company's net open position. Buying

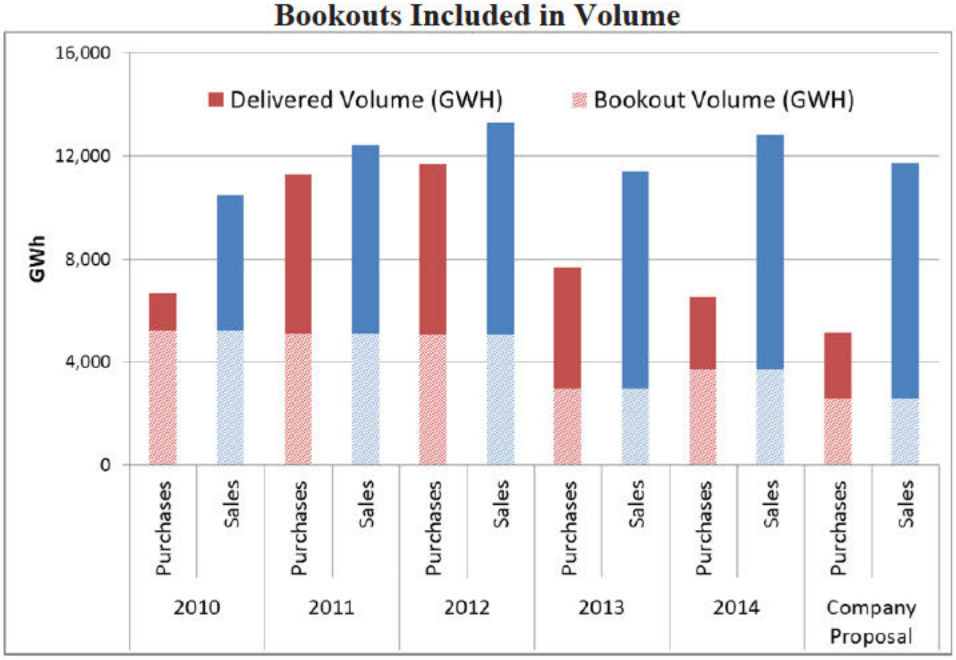
[23] ICNU/100, Mullins/13.

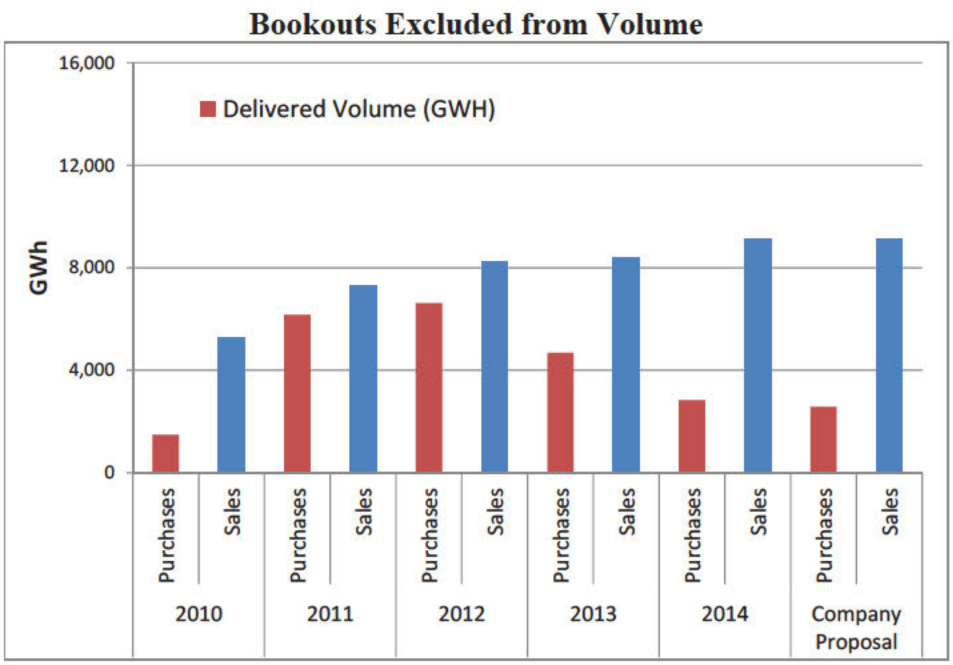
daily and monthly products limits the volumes that need to be acquired in hourly markets, which are subject to more price swings and volume limitations. As a result, the Company may buy a monthly product and sell daily products on a few days in a month, when load is lower than the monthly average or wind is higher than average. During those days, the portion of the Company's purchase and sale position that nets can be booked out. Bookouts can also occur as a result of load and variable generation forecast changes and units going on and offline as a result of forced outages. By design, bookout transactions are not modeled in GRID because it includes only physical transactions that perfectly match the net open position each hour. Without the Company's proposed adjustment in this case, the net cost of these balancing transactions will not be reflected in NPC.

Q. Have you prepared a comparison of historical and proposed system balancing volumes including bookouts?

A. Yes. As shown in Figure 2, when bookout volumes are accounted for, the Company's proposed system balancing volumes in this case are comparable to the historical levels.

FIGURE 2
Actual and Filed Sale and Purchase Volumes





Q. In docket UE 245, the Company argued against ICNU including bookout transactions in reviewing historical transaction levels in NPC. Has the Company's position changed?

A. No. In that case, the Company was responding to ICNU's misleading comparison of forecast NPC transaction volumes, excluding bookouts, to actual NPC transaction volumes, including bookouts. ICNU engages in a similar apples-to-oranges approach in this case, although here it compares the Company's actual NPC without bookouts to the Company's forecast NPC including a proxy for bookout transactions. Figure 2 demonstrates that, as long as bookout transactions are treated consistently on both sides of the equation, total transactions in this case are comparable to historical transaction levels.

Q. What is the second objection raised by ICNU to the Company's proposed system balancing modeling change?

A. Without citation to any evidence or authorities, ICNU argues that it is generally accepted that there is no systematic cost associated with system balancing because there is no bias between forward and spot market prices.[24] ICNU contends that system balancing transactions at spot market prices will be sometimes higher and sometimes lower than the forward market price and, in total, will balance out. Therefore, ICNU claims that a utility should be no better or worse off if it is ultimately required to transact in the spot market, as compared to the forward market.

Q. Is ICNU's objection valid?

A. No. The price differential is not a quantification of changes in price between a

[24] ICNU/100, Mullins/10.

forward period and the spot market for the same transaction. As described earlier, the Company's adjustment calculates the difference in realized prices for transactions during a month versus the average market price over that same month, and applies that differential to short-term system balancing transactions in GRID. The average realized price of the Company's transactions is dependent on the timing of each transaction within the month. As illustrated in Confidential Figure 1, 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. ICNU acknowledges that pricing will vary based on these timing differences[25] yet dismisses the fact that a forward market does not supply a product precisely shaped to the Company's purchase position and/or sale position for a month.

Mr. Graves' testimony provides additional refutation of the economic theory underlying ICNU's argument.

Q. What is the third objection raised by ICNU to the Company's proposed system balancing modeling change?

A. ICNU suggests that the Company's proposed system balancing costs are a result of forward hedging transactions and thus incorporate historical losses between the forward period and the prompt period.[26] In other words, ICNU claims that the historical data used to calculate the adjustment is actually a measure of the difference between actual market prices and hedged prices during the same period. ICNU also

[25] ICNU/100, Mullins/16.
[26] ICNU/100, Mullins/15-16.

claims that the Company should have a greater volume of sales transactions than purchase transactions to better represent historical hedging activities.[27]

Q. Are the historical transactions on which the Company's adjustment is based considered hedging?

A. No. ICNU's understanding and characterization of the Company's adjustment is entirely incorrect. The Company's adjustment does not determine the quantity or cost of forward hedging transactions during the test period. As explained above, and in my direct testimony, the Company's adjustment is based on the cost of balancing transactions done in the daily and hourly markets; the adjustment accounts for the timing of these transactions as they are executed to balance the system over time. 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. Because the Company's counterparties can make operational changes on a day-ahead basis, for instance by committing gas units online, they will have more flexibility than on an hour-ahead basis, which should increase market liquidity and market depth. As such it is prudent for the Company to reduce its open position on a day-ahead basis, rather than leaving it to the hourly market. The Company's adjustment is not calculated using losses on hedging transactions, nor is it applied to forward hedging contracts during the test period.

Q. Does the Company's proposal incorporate historical losses between the forward period and the prompt period?

A. No. The Company limited the calculation of its adjustment to transactions with a

[27] ICNU/100, Mullins/15-16.

delivery period of less than one week, as these are necessary to balance the Company's system and cannot be postponed.

Q. Is it appropriate to impute a larger volume of sales than purchases to the Company's GRID result as ICNU suggests?

A. No. ICNU's argument 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. As demonstrated in Figure 2 above, the Company's forecast system balancing transactions (both purchases and sales) are comparable to actuals and do not show disproportionate sales volume.[28]

Moreover, the Company's system must remain balanced over every period. ICNU's proposal would introduce substantially more sales than purchases without any offsetting change in generation or load. Thus, ICNU's proposal is entirely unrealistic.

Q. What is the fourth objection raised by ICNU with regard to the Company's proposed system balancing modeling change?

A. ICNU claims that the Company's adjustment incorporates a bid-ask spread into the hourly market prices included in GRID.[29] In discovery, ICNU explained that the Company has proposed to model a bid-ask spread here because it is "modeling a purchase price in the GRID model that is higher than the sales price for the same

[28] PAC/100, Dickman/24-25.
[29] ICNU/100, Mullins/16.

market."[30]

Q. Is ICNU's claim valid?

A. No. The Company's proposal is not attempting to measure or impose bid-ask spreads.

Q. What is a bid-ask spread?

A. A bid-ask spread is the difference between the highest price that a buyer is willing to pay for an asset and the lowest price for which a seller is willing to sell it.[31] A key component of the definition is that the buyer and seller are bidding on the same asset, *i.e.*, the buyer and seller are bidding in the same market *at the same time*.

Q. Why is the Company's proposal not a bid-ask spread?

A. The Company's adjustment measures the difference between the actual prices received for hourly and daily market transactions and the historical daily market prices. 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—a fact that ICNU concedes.[32] GRID does not produce realistic weighted average purchase prices or sales prices for its day-ahead and real-time transactions relative to the Company's Official Forward Price Curve, which provides an estimate of the average market price for each month. The Company's proposal results in more accurate weighted average purchase prices and sales prices for these transactions.

Q. Does the Company's adjustment even make sense as a bid-ask spread?

A. Not at all. As noted above, a meaningful bid-ask spread assumes that buyers and

[30] Exhibit PAC/508, ICNU Response to PacifiCorp's Data Request No. 3.
[31] http://www.investopedia.com/terms/b/bid-askspread.asp.
[32] ICNU/100, Mullins/16.

sellers are providing prices for the same item. But, as admitted by ICNU, the Company's purchase and sale volumes do not have comparable delivery patterns. The GRID model will never forecast both system balancing sales and purchases at the same market point in a single hour.

Q. Does ICNU recognize that the Company's proposal does not make sense as a bid-ask spread?

A. Yes. ICNU agrees that modeling a bid-ask spread has no relationship to system balancing costs.[33]

Q. ICNU also argues that the Company's adjustment is flawed because it results in a "negative bid-ask spread."[34] How do you respond?

A. What ICNU refers to as a "negative bid-ask spread" is actually a reflection of the fact that in some months the Company was able to sell power during higher average price times and purchased power in lower average price times. Again, because the Company's adjustment does not model bid-ask spreads, a negative differential in no way demonstrates that the adjustment is flawed.

Q. How is it possible that the Company could sell power during higher than average price times and purchase power in lower than average price times?

A. The Company has flexible generation resources that it can dispatch to meet its load requirements and make economic sales. To the extent these flexible resources have capacity that is not needed to balance load and variable resource output or for intra-hour regulation, their output can be dispatched in the market, and is done so preferentially when market prices are high. When market prices are low, these

[33] ICNU/100, Mullins/18.
[34] ICNU/100, Mullins/19.

resources can be backed off and lower cost market power can be acquired. The result is high sale prices and low purchase prices. The Company's proposal already reflects benefits from such periods of $3.2 million per year on a total company basis.

Q. Why isn't this a more frequent result?

A. The Company's flexible resources are limited and help meet significant intra-hour regulating needs. The benefit they provide is offset by the Company's load and variable resources, which often create surplus generation when prices are low and generation shortages when prices are high.

Q. What is ICNU's fifth objection regarding the Company's proposed system balancing modeling change?

A. ICNU claims that no other Northwest utilities make external adjustments to their models to compensate for these costs.[35]

Q. Is ICNU's argument accurate?

A. No. Idaho Power makes a modeling adjustment to its power cost model (Aurora) results used to set rates in Oregon, adjusting the prices of purchased power and wholesale sales compared to forecasted monthly market prices. This adjustment was approved by the Commission in Order No. 08-238.[36] The relevant portion of the order states:

> The volume of purchased power and surplus sales determined from the output of the Company's power cost model normalized run will be re-priced in the following manner:
>
> - Purchased Power
>   - Heavy Load – 3.9% above average Mid-C HL prices

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[35] ICNU/100, Mullins/9-10.

[36] *Re Idaho Power Co. Application for Authority to Implement a Power Cost Adjustment Mechanism for Electric Service to Customers in the State of Oregon,* Docket No. UE 195, Order 08-238, App. A at 3-4 (Apr. 28, 2008).

- o Light Load – 7.1% above average Mid-C LL prices
- Surplus Sales
  - o Heavy Load – 3.6% less than average Mid-C HL prices
  - o Light Load – 6.6% less than average Mid-C LL prices

Q. Does Idaho Power continue to include this adjustment in its power supply expense filings?

A. Yes.[37]

Q. Please explain your conclusion that Idaho Power makes an adjustment similar to the Company's system balancing proposal.

A. The Commission-approved adjustments to Idaho transaction pricing are based on the assumption that Idaho Power sells its excess power during lower-priced times and purchases power during higher-priced times. As noted above, this is also the premise of PacifiCorp's proposal. The Commission originally adopted the re-pricing adjustment in Order No. 05-871, where the Commission found that there was:

> …merit in Idaho Power's argument that its power purchases and sales should not be subject to flat prices. As Idaho Power indicated, when its loads are lower at off-peak times, it has excess power supply that it can sell; however, when its loads are higher, at on-peak times, it is short and must buy electricity on the market. Accordingly, we conclude that Idaho Power's net variable power costs should be priced using the April 30, 2004 price curve, on-peak prices for purchases and off-peak prices for sales.[38]

This is functionally the same adjustment the Company is making here, which accounts for the timing differences between purchases and sales.

Q. Are there any other relevant aspects of Idaho Power's re-pricing methodology?

A. Yes. The stipulation that included the re-pricing also approved a PCAM for Idaho Power, with dead bands, sharing bands, and an earnings test similar to the Company's

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

[38] *Re Idaho Power Co. Request for General Rate Revision*, Docket No. UE 167, Order No. 05-871 at 8 (July 28, 2005) (internal citations omitted).

current mechanism. This fact suggests that the parties to that stipulation, which included Staff and CUB, did not view that the costs addressed by the re-pricing were intended to be subject to the PCAM's dead bands.

Q. Do any other utilities apply external modeling adjustments that influence the relative cost of purchased power versus market?

A. Yes. PGE has included an assumed super-peak purchase power contract in its power cost forecasts for several years.[39] The cost of the modeled contract exceeds the monthly Mid-C HLH price, which is comparable to the outcome of the Idaho Power adjustment and the Company's proposal in this docket with respect to increasing the modeled cost of short-term purchases.

Q. Has ICNU itself proposed a very similar type of adjustment in PGE's current rate case using historical market prices?

A. Yes. In PGE's current rate case, docket UE 294, ICNU proposed an adjustment 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.[40] ICNU's adjustment was based on three years of actual transactions (both sales and purchases) made by PGE at COB. ICNU then aggregated the margins for each year, separately for sales and purchases, to develop the purported economic benefits associated with PGE's COB transactions.

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[39] *See, e.g.*, *Re Portland General Electric Co. 2015 Annual Power Cost Update Tariff*, Docket No. UE 208, Order No. 09-433 at 3 (Oct. 30, 2009). The Commission approved the Super Peak contract in 2007. *Re Portland General Electric Company*, Docket No. UE 180, Order No. 07-015 (Jan. 12, 2007). It appears that the super peak contract has at times been an actual contract, but in PGE's most recent rate case it is a hypothetical contract used for modeling purposes only.
[40] *Re Portland General Electric Co. Request for General Rate Revision*, Docket No. UE 294, ICNU/100, Mullins/9.

Q. How did ICNU justify using the historical prices to adjust prospective NPC?

A. ICNU argued that the

> …historical economic benefits from COB market transactions, relative to the Mid-C market, are a fair estimate of the level of economic benefits attributable to COB market activity expected in the test period. Because these economic benefits are driven by the difference in market prices between the two markets, rather than the overall level of market prices, the Company will be able to derive economic benefits from the spreads between the two markets, regardless of market conditions.[41]

Q. Did ICNU provide any other justification for its adjustment?

A. Yes. ICNU justified its adjustment, which would have reduced PGE's NPC, based on the claim that PGE consistently over forecasts its NPC and that its proposed downward adjustment was therefore warranted.[42]

Q. How is ICNU's docket UE 294 adjustment similar to the Company's proposal here?

A. Both adjustments rely on three years of historical actual market prices to make an outside-the-model adjustment to test period market transactions. Second, both rely on differences in market prices that are expected to remain consistent regardless of the overall market prices. Third, PacifiCorp's adjustment is intended to capture costs that are not modeled in GRID and is intended to remedy the Company's consistent under forecasting, while ICNU justified its PGE adjustment for the same, albeit opposite, reason.

Q. What is ICNU's sixth objection regarding the Company's proposed system balancing modeling change?

A. ICNU appears to suggest that the Company's inter-hour wind and load integration

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[41] *Id.*
[42] *Id.* at 10-11.

charges already capture the costs associated with balancing the Company's system.[43]

Q. How are the inter-hour integration costs determined?

A. These values were calculated in the Company's 2014 Wind Integration Study (2014 WIS). In that study, system costs were calculated for two different scenarios. In the first scenario, gas plants were committed based on the actual load forecast, which represents the optimal commitment. In the second scenario, gas plants were committed based on the day-ahead load forecast, which represents the commitment decision in the Company's actual operations, where gas must be nominated in advance, and startup and shutdown constraints limit gas plant flexibility. The second scenario has higher costs, because the optimal commitment decision for the forecasted load may not be optimal for the actual load. Analogous studies were prepared to measure the incremental impact of forecasted and actual wind.

Q. Does the Company's forecast continue to over-optimize the gas plant commitment which the inter-hour integration charge accounts for?

A. Yes. The Company's gas plant screening process optimizes unit commitment based on a known forecast of wind and load, as well as outages, prices, and other inputs. These inputs do not change between the commitment decision and actual unit dispatch, so the Company's forecast does not otherwise account for the uncertainty between the forecast and actual operation.

Q. Does this capture the system balancing costs proposed by the Company?

A. No. The studies on which the inter-hour integration costs are based use the same hourly price forecasts previously employed by the Company, and are uniform across

[43] ICNU/100, Mullins/17-18.

each month. The integration costs thus only measure the cost associated with the achievable optimization of gas plant commitment based on forecasted information, rather than perfect optimization with perfect foresight of system requirements. ICNU's vague attempt to discredit the Company's current system balancing proposal by referencing these costs is baseless.

Response to ICNU's System Balancing Adjustments

Q. ICNU proposes elimination of the Company's market cap adjustment if the Commission adopts the Company's system balancing proposal. Does adoption of the Company's system balancing proposal negate the need for market caps as ICNU claims?

A. No. In the 2013 TAM, the Commission concluded that some form of market caps was required in GRID to produce a reasonable NPC forecast.[44] The Commission adopted Staff's approach to modeling market liquidity, measuring the caps based on the highest of four most recently available on- and off-peak monthly sales averages for each trading hub.[45] ICNU has not addressed why the Commission should reconsider this aspect of its order in the 2013 TAM.

Market caps are designed to impose liquidity constraints on the GRID model to prevent GRID from artificially increasing sales, especially to illiquid and high-priced markets. The Company's proposal to more accurately capture the cost of its system balancing transactions does not provide a substitute liquidity constraint. The effect of removing market caps would be to decrease the modeled costs of PacifiCorp's system balancing transactions by imputing unrealistic sales volumes in

[44] Order No. 12-409 at 7.
[45] *Id.* at 7-8.

illiquid markets. 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.

Q. Would removal of market caps artificially inflate the Company's sales volumes?

A. Yes. The removal of market caps results in a 10 percent increase in the total sales now modeled in this case (including the transactions added to NPC to better simulate total transaction levels resulting from standard blocks transactions). As demonstrated in Figure 2 above, the sales volumes modeled in the Company's filing are consistent with historical transaction levels. ICNU's approach, without market caps, is approximately seven percent over those historical levels (including bookouts).

Q. Please describe ICNU's alternative adjustment relating to system balancing costs.

A. Based on ICNU's erroneous claim that the Company's proposal models a bid-ask spread, ICNU also recommends an alternative adjustment.[46] ICNU proposes to replace the Company's proposal with a $0.50/MWh spread between purchases and sales and eliminate market caps. ICNU argues that the bid-ask spread addresses PacifiCorp's concerns about the timing of short-term purchases and sales and effectively replaces market caps as a liquidity constraint.

Q. Please respond to ICNU's adjustment.

A. ICNU's alternative adjustment is a step backwards in terms of addressing the short-term transaction costs and market liquidity issues the Company faces in balancing its system. Conceptually, ICNU's adjustment is flawed and irrelevant because, as

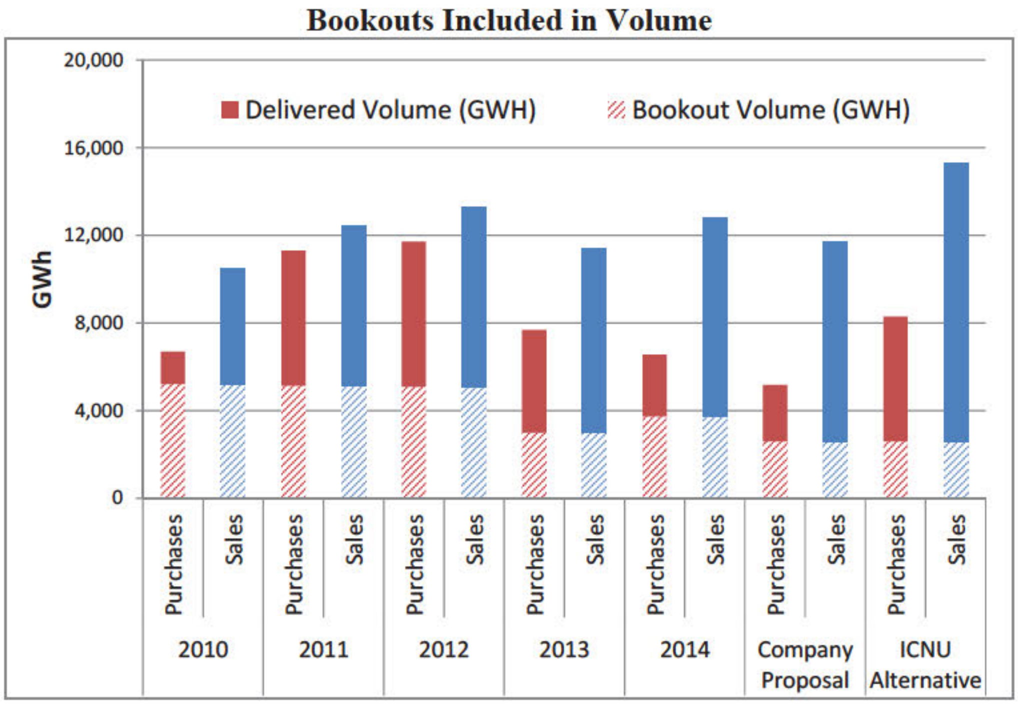
[46] ICNU/100, Mullins/19-20.

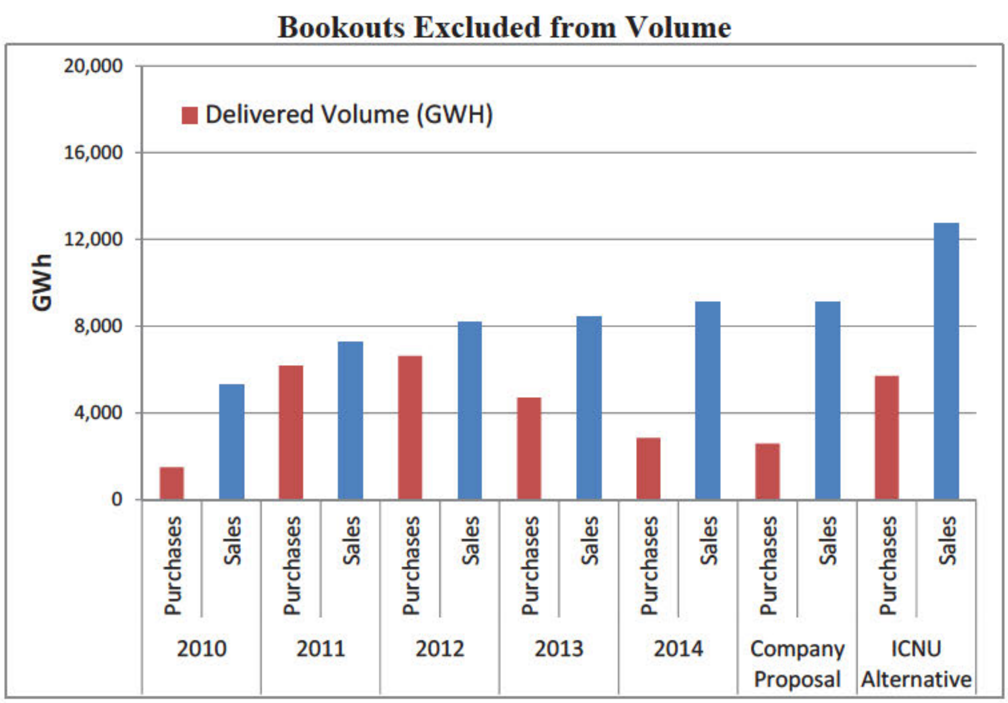
described above, the Company's proposal does not model bid-ask spreads. Operationally, ICNU's adjustment would result in a huge overstatement of the Company's short-term market sales. Starting with the 10 percent increase in sales volumes associated with market-cap removal, ICNU's bid-ask spread adjustment would increase sales by an additional 18 percent. The effect of these sales would be to decrease PacifiCorp's cost recovery for system balancing, the opposite of what is needed at this time.

Q. Have you prepared a chart showing the sales volumes levels under ICNU's alternative adjustment?

A. Yes. To ensure an apples-to-apples comparison, the Company added the same bookout volumes to ICNU's proposal that the Company includes in its own proposal. Figure 3 demonstrates the disproportionately high sales volume produced by ICNU's alternative adjustment, when viewed with bookouts or without them.

FIGURE 3
Actual and ICNU Proposed Sale and Purchase Volumes





Regulation Reserves

Introduction

Q. As background, please describe the changes to the modeling of regulation reserves the Company proposed in its Initial Filing.

A. The Company made two proposals related to modeling of regulation reserves in its Initial Filing. First, the Company included flexibility reserve benefits resulting from the Company's participation in the EIM. These benefits reflect the reduced regulating reserve requirement modeled in GRID resulting from the Company's share of the reserve benefit in the EIM. Second, the Company recommended modeling regulation reserve requirements on an hourly basis, rather than using flat monthly amounts.

Q. In its Reply Update, did the Company make other adjustments to the flexibility reserve benefit?

A. Yes. As described above, the Company updated its filing to reflect additional reserve savings from NV Energy's participation in the EIM. The Company also accepted ICNU's adjustment to increase the flexibility reserve benefits associated with the future participation of PSE and APS in the EIM.

Q. Do the parties propose adjustments in this case related to the Company's regulation reserves?

A. Yes. Staff proposes an adjustment reducing regulation reserves based on within hour scheduling. ICNU proposes three adjustments, based on: (1) a reduction of the regulation reserve requirement related to the Company's recent performance under the North America Electric Reliability Corporation (NERC) Critical Performance

Standards 2 (CPS2); (2) what ICNU describes as a correction to the treatment of interruptible loads in the calculation of the regulation reserve requirement; and (3) a proposal that the Company utilize 50 MW of its dynamic transfer capability between its east and west BAAs for the transfer of reserves.

Response to Staff's Regulation Reserve Adjustment

Q. Please describe Staff's reserve adjustment.

A. Staff proposes reducing the regulation reserve requirement to account for scheduling of load and wind on a within-hour basis through the EIM.[47] Staff seeks reserve requirement reductions in the Company's west and east BAAs of 44 MW and 68 MW, respectively. This reduces NPC by $1.4 million.

Q. What is the basis for Staff's adjustment?

A. Staff argues that when the Company schedules on a within-hour basis, as Staff claims the Company does through the EIM, the Company has less need for regulating reserves as compared to hour-to-hour scheduling. Staff assumes that EIM results in within-hour scheduling capability for load and wind generation that will allow for rebalancing of reserves and a reduction in the amount of reserves required to be held over an hour.

Staff calculated its adjustment using an alternative scenario considered in the Company's 2012 Wind Study (2012 WIS), filed with its 2013 Integrated Resource Plan (IRP). The scenario assumed that a market structure and adequate market depth existed in 30-minute intervals such that the Company could rebalance system deviations with market transactions. Reserves deployed in the top half of an hour

[47] Staff/100, Ordonez/12-16.

were assumed to be replaced by market transactions for the bottom half of the hour, freeing up those resources to provide reserves again and reducing the need for additional reserves to cover further system deviations.

Q. Does EIM allow for the within-hour rebalancing of system deviations as contemplated in the 2012 WIS?

A. No. The key assumption in the 2012 WIS scenario is that the Company can buy or sell any amount to minimize the resources held as reserves for the next 30-minute interval. The EIM, however, transacts only energy and does not include capacity that can be used to rebalance reserves, which participants must supply from their own resources. In order to participate in EIM, the Company must demonstrate that it has sufficient flexible resource capacity to meet its needs for the next hour. These resources cannot be dispatched to support sales outside of the EIM within that hour. If they are called upon to serve the CAISO's requirements, the result is an export to the CAISO, which is captured in the inter-regional dispatch benefit.

Q. Has the Company already accounted for EIM-related reductions in regulation reserves in this case?

A. Yes. The Company included a flexibility reserve benefit to account for the fact that, because the Company's regulating reserves are not expected to be called upon at the same time as the combined EIM participants, a smaller volume is sufficient to cover the combined requirement.

Q. Outside of the EIM and the CAISO, do 30-minute balancing markets with adequate depth exist in Western Electricity Coordinating Council (WECC) footprint?

A. No. The Company has not transacted for any within-hour balancing products, and is not aware of any counterparties that transact for such products on a regular basis.

Q. Do you have any additional comments on Staff's adjustment?

A. Yes. Staff's adjustment ignores the costs of relying upon the market for meeting short-term resource requirements. It assumes that the Company's hourly market price forecast is a reasonable proxy for the revenues from reserves freed up by 30-minute balancing, and does not present any evidence in support of this assumption.

Q. Is Staff's assumption about the costs of short-term transactions valid?

A. No. The Company's loads and variable resources are interspersed with other utilities in the region, which may result in similar 30-minute balancing needs. This would result in price differentials between periods when the Company is long and looking to sell in the 30-minute market and when it is short and looking to buy in the 30-minute market. This price differential is comparable to the Company's proposed day-ahead and real-time system balancing adjustment and is not reflected in Staff's proposal.

Response to ICNU's Regulation Reserve Adjustments

NERC CPS2 Adjustment

Q. Please describe ICNU's reserve adjustment based on NERC CPS2 performance.

A. ICNU proposes a large reduction in the forecasted regulation reserve requirement, allegedly to account for the Company's recent CPS2 score performance. ICNU reduces reserves for the Company's west BAA by 86 MW and for the east BAA by

159 MW. This cuts the Company's regulation reserves by more than one-third and reduces NPC by $2.8 million.[48]

Q. What is the rationale for ICNU's adjustment?

A. ICNU argues that the Company's actual operations do not correspond to the reliability metric that is used to determine the regulation reserves modeled in GRID. Specifically, ICNU claims that the Company calculates its regulation reserve requirement assuming 99.7 percent reliability, while in actual operations the Company had a much lower reliability percentage, as reflected in the Company's CPS2 score.

Q. What does CPS2 measure?

A. CPS2 is a measure of how often the Company remains within the specific reliability standard adopted by NERC. CPS2 states that a balancing authority shall operate such that its average area control error (ACE) is within its L_{10} limit (a threshold determined by NERC) for at least 90 percent of clock-ten-minute periods (six non-overlapping periods per hour) during a calendar month.

Q. Under the CPS2 standard, could the Company avoid NERC penalties for falling outside the L_{10} limit as long as it happened less than 10 percent of the time?

A. Yes. Holding enough regulation reserve to maintain ACE within the specified limits in 90 percent of a month was sufficient for compliance. The magnitude of the deviation in the periods that were outside the limits had no bearing on compliance

[48] ICNU/100, Mullins/23.

with the standard. In other words, CPS2 measures the number of violations, not the magnitude of the violation.[49]

Increases in variable generation output across the interconnection have led to more frequent and larger deviations and larger regulation reserve requirements. Allowing utilities to avoid penalties for deviations in 10 percent of a month shifted the burden for these requirements on the rest of the interconnection. At the same time, correcting an individual deviation that worsens the overall interconnection was also harmful. The CPS2 standard focused on individual requirements and did not account for the impacts on the interconnection as a whole.

Q. Is the Company currently required to adhere to the CPS2 requirement?

A. No. As of March 1, 2010, the Company began operating under the Reliability-Based Control (RBC) Proof-of-Concept Field Trial under Project 2007-18 for the WECC and is no longer subject to CPS2.

This new WECC standard is tied to changes in PacifiCorp's ACE as they affect interconnection frequency. As frequency fluctuates, real-time operators use Company assets to maintain or correct ACE to support system frequency. Any ACE deviation outside the allowable limit that is contributing excess or deficient frequency must be corrected within a 30-minute period. All deviations must be corrected within 30 minutes 100 percent of the time or the Company is in violation and non-compliant.

Q. Has the Company's regulation requirement changed as a result of the RBC standard?

A. Yes. Whereas previously the Company was not penalized if it did not meet the CPS2

[49] *See* Exhibit PAC/508, ICNU Response to PacifiCorp Data Request No. 8.

standard in up to ten percent of a month, it must now ensure that it is able to correct 100 percent of the deviations in a month. Since deviations are now measured relative to the impact on the interconnection as a whole, many deviations in the Company's ACE no longer require immediate action on the part of the Company and the corresponding CPS2 scores may be lower. But regardless of CPS2 scores, the Company now may be required to correct the maximum possible deviation when it contributes to WECC frequency deviations, and must maintain at all times regulation resources sufficient to do so.

Q. How are the Company's regulation resources dispatched to meet the RBC standard?

A. If the Company's deviation offsets the interconnection's deviation, no dispatch of regulation resources is required, though they may still be dispatched to control for local transmission limits or to keep the total deviation to a manageable level. If a generator or load trips offline elsewhere in the interconnection, the interconnection's deviation may change instantaneously, and the Company's 30-minute time limit begins. Because the Company's loads and variable resources continue to change once the 30-minute clock starts, they may exacerbate the deviation that must be corrected. To provide assurance of meeting the 30-minute compliance deadline in spite of changing conditions, the Company dispatches regulation reserves to correct the deviation within 20 minutes and makes adjustments as conditions change over that period.

Q. How is this regulation dispatch under the RBC standard different from that under the CPS2 standard?

A. Because not all deviations have to be immediately corrected under the RBC standard, regulation resources held in reserve will be dispatched less often. In addition, since the time horizon is longer, they may be able to ramp more slowly, which reduces wear and tear on generator components.

Q. Have the changes to maintain RBC compliance reduced the Company's CPS2 scores?

A. Yes. There are two factors in the RBC standard that contribute to lower CPS2 scores. First, the RBC standard requires utilities to correct deviations outside the allowable limit within a 30-minute period. A deviation that was corrected in the 21st minute could result in two ten-minute periods being outside the CPS2 limit, while remaining compliant with the RBC standard. Second, not all deviations must be corrected under the RBC standard. If the Company's deviation is in the opposite direction from the frequency deviation of the interconnection as a whole, it does not have to be corrected since that would move the interconnection further from its target frequency.

Q. Is a lower CPS2 score relevant to the regulation reserves the Company must have available to comply with the RBC standard?

A. No. The RBC standard does not consider CPS2 scores. ICNU's premise that a lower CPS2 score indicates a need for fewer reserves to comply with the RBC standard is false.

Q. ICNU cites a 2012 WIS Technical Review Committee (TRC) comment about the justification for the 99.7 percent exceedance level.[50] ICNU claims that the TRC found that the Company had failed to appropriately account for reserve savings in the 2012 WIS. Is this true?

A. No. The 2012 TRC stated only that the Company did not explain why it used a 99.7 percent exceedance. The TRC did not conclude that the Company should have used a lower exceedance level.

Q. ICNU further claims that the Company did not respond to the concerns raised by the 2012 TRC.[51] Is this true?

A. No. The 2014 TRC Technical Memo states clearly that the "Company should be acknowledged for the diligent efforts it made in implementing the recommendations by the TRC from the 2012 wind integration study in the 2014 study."[52] The TRC specifically noted that "a discussion on the selection of a 99.7 percent exceedance level when calculating regulation reserve needs was provided, including a description of how the WIS results inform the amount of regulation reserves planned for operations."[53] In addition, the TRC commended the Company's modeling for accounting "for estimated benefits from PacifiCorp's participation in the energy imbalance market (EIM) with the California Independent System Operator

[50] ICNU/100, Mullins/26.
[51] ICNU/100, Mullins/27.
[52] PacifiCorp 2014 Wind Integration Study Technical Memo (12/22/14). Available online at: http://www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Integrated_Resource_Plan/2015IRP/2015IRPStudy/2015IRP-2014WIS_TRC-TechnicalMemo_12-22-14.pdf.
[53] *Id.*

(CAISO)"[54] The TRC concluded: "The 2014 wind integration study report thoroughly documents the company's analysis."[55]

Q. Did the 2014 TRC find anything inappropriate about the Company's use of a 99.7 percent exceedance level?

A. No. This is a material fact that ICNU fails to mention in its testimony.

Q. Has the Company performed any reliability analysis of regulation requirements based on the 99.7 percent exceedance level?

A. Yes. This analysis indicated that the Company may need to consider more regulation reserves, not less, to maintain compliance with the RBC standard in the future. Specifically, the Company applied the WIS methodology results to the 2013 actual load and wind data. This resulted in reserve failures, where the calculated reserve requirement was short of the actual requirement, in two percent of the periods for the west BAA and 1.4 percent of the periods for the east BAA. This shows that the WIS results used in the Company's forecast are already conservative.

Q. What is the Company's actual performance under the RBC standard?

A. To date, the Company has maintained 100 percent compliance with the RBC standard.

Q. Does ICNU's proposed reduction in regulation reserves capture the costs of compliance with the RBC standard under which the Company currently operates?

A. No. On its face, ICNU's proposal would result in insufficient regulation resources in ten percent of each month. If any of those time periods occurred when WECC as a

[54] *Id.*
[55] *Id.*

whole was also short, the Company would have to choose between curtailing firm load (*i.e.*, retail customers) or fines from non-compliance with the RBC reliability standard.

Interruptible Loads Adjustment

Q. Please describe ICNU's reserve adjustment related to interruptible loads.

A. ICNU proposes that the Company's interruptible loads count only to the load-following portion of the reserve requirement.[56] This means that these interruptible loads would cover variations over time frames of up to an hour, rather than the full regulation requirement, which covers variations over both 10-minute periods and hourly periods. Under ICNU's proposal, in periods where the interruptible load under these contracts was higher than the load following requirement, the excess would not be counted as reserves. This adjustment increases NPC by $0.7 million.

Q. Do you agree with this proposal?

A. No, for two reasons. First, contracts for interruptible loads also count toward meeting the non-spinning portion of the contingency reserve requirement, so only interruptible loads in excess of the non-spin contingency requirement are counted toward the regulation requirement. The Company expects that the full interruptible load can be utilized between the contingency and regulation requirements. Whether these interruptible loads are designated as non-spin contingency reserves or regulation reserves in GRID should not affect how the remaining requirement will be met. For modeling convenience, the Company applies the credit to the regulation requirement and allows any excess as a credit to offset the non-spinning contingency requirement.

[56] ICNU/100, Mullins/22-23.

Second, the relevant interruptible loads can be curtailed in less than ten minutes, which is the same time frame over which the regulating requirements from the Company's WIS were measured. ICNU does not provide any basis for restricting these products to providing following service.

BAA Dynamic Transfers Adjustment

Q. What is ICNU's adjustment related to dynamic transfers between BAAs?

A. Based on the Idaho Power Asset Exchange, ICNU proposes that the Company utilize 50 MW of its dynamic transfer capability between its east and west BAAs for the transfer of reserves.[57] ICNU's proposed adjustment results in a reduction to NPC of $0.3 million. Staff makes a similar proposal, although Staff did not quantify its adjustment.[58]

Q. Do you agree with ICNU's adjustment?

A. No. As described below, however, if the additional 50 MW of dynamic transfer capability is utilized in GRID to provide reserves, an associated reduction in transmission available for energy transfers must also be accounted for.

Q. ICNU claims that the Company's increased dynamic transfer capability and participation in EIM result in greater ability to transfer flexibility reserve requirements between its BAAs. Is this accurate?

A. No. There is no mechanism by which flexibility reserves can be transferred between the Company's BAAs under the EIM. The CAISO requires each participating BAA to pass a flexible resource test, demonstrating that it has sufficient flexible resources to meet its requirements. The Company's BAAs must pass this test independently.

[57] ICNU/100, Mullins/31-33.
[58] Staff/100, Ordonez/8-11.

Q. Is there another mechanism by which reserves can be transferred between the Company's BAAs?

A. Yes. The Company can transfer contingency reserves from one BAA to the other. However, such transfers must be scheduled in advance across a path with dynamic transfer capability, which is then no longer available for use within the EIM. ICNU's proposal does not account for the restrictions on transfer capability that such reserve transfers would require.

Q. Are there other limiting factors on the Company's ability to transfer reserves between its BAA's?

A. Yes. While the Jim Bridger plant is electrically part of the Company's West BAA, any EIM dispatch of Jim Bridger to the Company's West BAA utilizes dynamic transfer capability. This is true both before and after the Idaho Power Asset Exchange takes effect. Because the modeled reserve capability of the Jim Bridger plant is equal to the assumed increase in the Company's dynamic transfer rights, it is not clear that benefits proposed by ICNU can be realized in actual operations.

Q. If the Commission accepts this adjustment, are there any other considerations which should be accounted for?

A. Yes. In some periods, the proposed reserve transfers can leave one BAA short of reserves. The GRID model does not include costs for those shortages, so they are effectively zero cost reserves. If the Commission decides that it is reasonable to assume reserve transfers of up to 50 MW between PacifiCorp's BAAs, the transfer should first be used to minimize reserve shortages, without regard for the economics reported by GRID. The least cost transfer option which does not result in reserve shortages could then be selected. In addition, the Commission should allow PacifiCorp to model the transmission limitations necessary to carry out the transfer.

Inter-regional EIM Dispatch Benefits

Introduction

Q. In the Initial Filing, how did the Company model the inter-regional dispatch benefits resulting from its participation in the EIM?

A. The Company used the results of EIM operation during December 2014 and January 2015 to determine the benefits included in the Initial Filing. The export benefit is the difference between the export revenue and the expense of the Company generation assumed to be dispatched to support the transaction. The export benefit is also tied to the transmission capacity available for EIM transactions in each month of the forecast period. The import benefit is the difference between the import expense and the expense of the Company generation that would have been dispatched but for the transaction.

Q. Do parties support the Company's approach to modeling the inter-regional EIM dispatch benefits?

A. Not entirely. While ICNU or CUB do not explicitly reject the Company's approach to calculating the inter-regional dispatch benefits, both are critical of certain aspects of the Company's modeling. Staff, on the other hand, observed that the Company's approach was not unreasonable and that Staff looked forward to updated historical information.[59]

[59] Staff/100, Ordonez/13.

Q. What is ICNU's criticism of the model inputs?

A. ICNU has two concerns with the Company's modeling.[60] First, ICNU criticized the Company's use of only two winter months to forecast the benefits and believes that there are "seasonal benefits" that the Company is not capturing in its model. Second, ICNU claims that the Company's modeling did not properly account for the benefits resulting from the participation in the EIM of NV Energy, PSE, and APS.

Q. What are CUB's concerns about the EIM modeling?

A. Like ICNU, CUB is also concerned that the limited historical data is not representative of the actual level of benefits that will result from a full year of EIM participation.[61]

Q. Do ICNU and CUB propose specific adjustments related to their concerns with the limited and seasonal nature of the historical EIM results?

A. Yes. ICNU provides specific adjustments to reflect "seasonality benefits" and the addition of participants in the EIM Market. CUB does not provide a specific recommendation on the forecast benefits, but recommends that the Commission require the Company to defer the difference between the actual and forecast benefits outside of the PCAM for this case only.

Q. Does the Company's Reply Update respond to concerns about the limited historical data from the EIM used in the Initial Filing?

A. Yes. The Company's reply testimony incorporates additional historical results for the EIM through June 2015. The inter-regional dispatch benefits in the Company's Reply Update therefore reflect seven months of historical data. The Company intends

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[60] ICNU/100, Mullins/35-36.
[61] CUB/100, Jenks-Hanhan/8.

to reflect results through September 2015 in its Final Update. The inclusion of additional EIM results, including the summer months, responds directly to the parties' concerns about the limited amount of historical data available for the Initial Filing.

Q. Did the Company provide greater weight to the June 2015 results in the Reply Update, responding to ICNU's and CUB's seasonality concerns?

A. Yes. As an interim measure until further historical results are available, the Company applied the June 2015 results to the summer months in the 2016 test period. This modeling adjustment is described in more detail below.

Q. Does the Company's Reply Update also provide additional inter-regional dispatch benefits to account for new EIM participants?

A. Yes. As described below, the Company increased its EIM inter-regional dispatch benefits to account for the participation of NV Energy, PSE and APS in the EIM in 2016.

Response to ICNU's EIM Inter-regional Dispatch Benefit Adjustments

Q. Please describe ICNU's seasonality adjustment.

A. ICNU proposes a modeling adjustment to shape the economic margins used to calculate the dispatch benefits based on the relative market spreads between Mid-C and COB market prices between December 2014 and January 2015 and the test period. ICNU claims that this adjustment will appropriately capture the benefits for a full year. ICNU's proposal results in an NPC reduction of $0.4 million on an Oregon basis, with EIM inter-regional benefits with the CAISO totaling $9.9 million in the forecast period on a total company basis.

Q. Do you agree with ICNU's adjustment?

A. No. First, ICNU's proposed adjustment contains incorrect operational assumptions and formula errors. ICNU assumes the EIM export volumes will be identical in each month of the forecast period, whereas the Company's proposal included volumes based on the transmission available for EIM transfers in each month of the forecast period. ICNU's calculation of the import margin also appears to be understated by roughly 80 percent due to a formula error. While correction of these errors increases ICNU's adjustment, they demonstrate the adjustment's analytical infirmities.

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

Finally, I would note that the updated NPC included in this testimony incorporates additional historical results through June 2015. The inter-regional dispatch benefits in the Company's Reply Update therefore reflect seven months of historical data and the Company intends to reflect results through September 2015 in its Final Update. The inclusion of additional EIM results responds to the concerns of both ICNU and CUB.

Q. What are the factors underlying EIM import and export benefits?

A. Fundamentally, the EIM dispatches the least cost resources to meet demand in each five minute interval, but the resources and demand are subject to certain additional constraints.

First, EIM participants are required to have balanced base schedules for the upcoming hour – by submitting resource schedules that match their forecasted demand. Second, each EIM participant must also hold back sufficient regulation reserve capacity from hourly markets or base load service to cover these expected variations. This means that, other than the savings from the flexibility reserve diversity, participants could cover their own requirements without EIM. The combined pool of flexible resource capacity held back from hourly markets and base load service by all participants is made available for dispatch by EIM.

The EIM benefits are the result of the price differential between the specific resources in the flexible resource pool, for example, purchasing energy from a lower cost generator than is available in a participant's own fleet. The Company's EIM benefits are a function of the margin between the Company's available flexible resources and the CAISO's available flexible resources.

Q. What does this mean with regard to ICNU's proposal?

A. The Mid-C price is derived from the balance of loads and resources of a wide number of utilities around the Northwest. But the only prices that are relevant in EIM are those of the resources with capacity available for export to the CAISO, primarily from the Company's combined cycle combustion turbines (CCCTs). This capacity is held available, even when it costs less than the hourly market price, because committing to an hourly market sale could leave the Company short during part of an hour if load or wind changes. Committing to a five minute EIM transaction has less risk, as dispatch will be adjusted in the next five-minute period and other participants are required to provide sufficient flexible resources to meet its expected requirements through the hour. Thus, the Mid-C price is not a good measure of the Company's EIM participating resource costs. For the same reason, COB is also not a good measure of the CAISO's EIM participating resource costs.

Q. Do the more recent historical results undermine ICNU's proposed adjustment for seasonality?

A. Yes. First, as I mentioned above, the Company's EIM export benefits were negatively correlated with the Mid-C–COB market price spread over the December 2014 to June 2015 time frame. Second, the month with the highest benefits was June 2015, and it had the lowest spread. This indicates that while there may be seasonal variations in benefits, ICNU's proposal does not capture them accurately.

Q. Do you have an alternative proposal to capture seasonal variations in EIM benefits?

A. Yes. The export benefit in June 2015 was roughly double that of the first six months of EIM operation, where the monthly benefits were fairly consistent. June 2015 was somewhat atypical, with low regional hydro run-off and high temperatures. In fact, the Company set a new all-time system peak on June 29, 2015. This makes it relatively representative of summer conditions. For the purposes of its Reply Update, the Company proposes that the forecasted EIM benefits for the months of June through September be based on June 2015 results, while the EIM benefits for the remaining months be based on the average results from December 2014 through May 2015.

Q. What is the impact of this interim proposal?

A. The EIM inter-regional benefit in the Company's Initial Filing was $8.4 million on a total company basis. Using the same method, but incorporating results through June 2015 would reduce this slightly to $8.3 million. Separating the results into two seasons as described above increases the benefit to $9.0 million, slightly lower than the $9.9 million benefit proposed by ICNU.

Q. How will the final EIM inter-regional benefits in the case be determined?

A. The Company proposes that its Final Update incorporate EIM benefit results through September 2015. At that time, the Company will have actual results for all of the summer months during 2015 and ten out of twelve months in a calendar year. The Company's forecast for June through September 2016 would be based on the average results from these four summer months, while the forecast for the remaining months will be based on the average results in the six other months. This should provide a reasonable estimate of the EIM inter-regional benefits in this case from transactions with the CAISO for the forecast period.

New Participant EIM Inter-regional Dispatch Benefit

Q. Please describe ICNU's proposed adjustment to inter-regional dispatch benefits for new EIM participants.

A. ICNU contends that the Company will receive increased inter-regional dispatch benefits once NV Energy, PSE, and APS join the EIM. ICNU proposes an adjustment that is based on the transfer capability between PacifiCorp and the new participants and the benefit from the Company's historical EIM transactions with the CAISO. ICNU's adjustment reduces total company NPC by $3.2 million, or $0.8

million allocated to Oregon. Of the $3.2 million in benefits proposed by ICNU, $2.1 million is related to NV Energy participation during all of 2016 and the remaining $1.1 million is the combined impact of PSE and APS participation during the last three months of 2016.

Q. Does ICNU's adjustment have merit?

A. In principle, the Company agrees that there will be additional inter-regional dispatch benefits once NV Energy, PSE, and APS join the EIM. While ICNU's proposal for $2.1 million in benefits from NV Energy has many flaws, the end result is similar to the $1.5 million in annual benefits the Company has incorporated in its Reply Update. ICNU's proposal to include an additional $1.1 million in benefits for the three months of PSE and APS EIM participation in the forecast period, however, is significantly overstated.

Q. How do you conclude that benefits associated with PSE and APS are overstated?

A. The E3 studies for PSE and APS estimated a total annual benefit to all existing participants (CAISO, PacifiCorp, and NV Energy) of just $2 million per year. ICNU estimates benefits to PacifiCorp alone of $4.4 million per year. This significant discrepancy demonstrates that ICNU's proposed adjustment is entirely unreasonable.

Q. What benefit do you propose for EIM inter-regional dispatch with PSE and APS?

A. The Company proposes that the E3 study results be allocated among the existing participants based on same ratios employed by ICNU with regard to the flexibility reserve diversity benefits from these participants. The proposed method results in total company benefit of $83,000 dollars over the three months PSE and APS are expected to participate in EIM during the forecast period. This result has not been discounted to account for the difference in benefits between the higher cost summer period, and the lower cost October through December period included in the forecast. The Company has incorporated this benefit in its Reply Update.

NV Energy Inter-regional Dispatch Benefit

Q. What benefit do you propose using for EIM inter-regional dispatch with NV Energy?

A. The Company proposes to calculate benefits from the addition of NV Energy to the EIM using the same approach as used for the inter-regional exports between PacifiCorp and the CAISO, but with reduced margins to reflect diminishing returns from incremental transmission capability. ICNU made a similar calculation in its adjustment for the benefits related to new EIM participants, but as described later in my testimony, its adjustment overstated the potential transfers and margins. The Company's adjustment results in inter-regional benefits from the EIM participation of NV Energy totaling $1.5 million per year on a total company basis.

Q. Please explain why the additional EIM transmission capacity available when NV Energy begins to participate will not generate the same margins as the existing transmission between PacifiCorp and the CAISO?

A. NV Energy is interconnected with the CAISO and has relatively low regulating requirements, so adding NV Energy to the EIM is likely to result in additional EIM export benefits for the Company primarily as a result of transfers through NV Energy to the CAISO. Because these transfers represent an increased volume over current EIM exports, these additional exports will necessarily come from higher cost generators on the Company's system than the existing exports, with lower realized margins. Utilization of the additional transmission would also be lower since the CAISO may frequently be able to meet its demand with the Company's existing exports. Finally, the incremental export volume will result in displacement of the CAISO resources with lower marginal costs, reducing the market clearing price and the revenues associated with the both the Company's existing exports and the incremental exports through NV Energy. These factors are represented in the E3 study results for NV Energy, which calculated benefits to existing participants that were just 21 percent more than the level achieved between the Company and the CAISO alone. The Company therefore proposes that this factor be applied to the export margin realized under the current CAISO-PacifiCorp EIM. When this margin is applied to the transmission capacity available between the Company and NV Energy, the result is an inter-regional benefit from the participation of NV Energy totaling $1.8 million per year on a total company basis.

Q. On an Oregon-allocated basis, what is the total additional benefit in the Reply Update related to the new EIM participants?

A. In its Reply Update, the Company included benefits of approximately $0.4 million Oregon-allocated, related to NV Energy, PSE, and APS.

Q. Please summarize your concerns with ICNU's proposed method for calculating inter-regional benefits from new EIM participants.

A. ICNU's calculation has two major flaws. First, the incremental benefits from exporting to new EIM participants are expected to be significantly different from the Company's current benefits when exporting to the CAISO. Notably, in its calculation, ICNU incorrectly applied the historical margin per available transmission capacity to the assumed volume of energy exports rather than the volume of transmission available. Correcting this error would have tripled ICNU's proposal to $6.3 million per year in benefits associated with NV Energy, and to $3.3 million for PSE and APS. The magnitude of these results demonstrates that ICNU's approach produces entirely unreasonable results when it is correctly applied.

Second, the transfer capability in ICNU's proposal is overstated, as it fails to account for the Company's transmission already being utilized in the forecast period.

Q. Is there documentation that indicates ICNU's proposed benefits associated with PSE and APS are overstated?

A. Yes. The E3 studies for PSE and APS estimated a combined annual inter-regional benefit to all existing participants (CAISO, PacifiCorp, and NV Energy) of just $2 million per year. Yet, ICNU proposes to include an additional $1.1 million in benefits for the three months of PSE and APS EIM participation in the forecast period. ICNU's adjustment is equivalent to $4.4 million in annual benefits to PacifiCorp alone. This significant discrepancy demonstrates that ICNU's proposed adjustment is unreasonable.

Q. Please further describe the first problem in ICNU's proposed method.

A. ICNU's primary flaw is to assume that more transmission capacity automatically translates into increased export volumes. For the Company to increase EIM exports, it must have additional resources available for EIM dispatch; these resources will necessarily be higher cost than those supplying the Company's current exports. Additional EIM participants will only import from PacifiCorp if they have resources that can be displaced, and which cost more than the Company's available resources. These factors result in lower export volumes and lower export margins, both of which would mitigate the incremental export benefit.

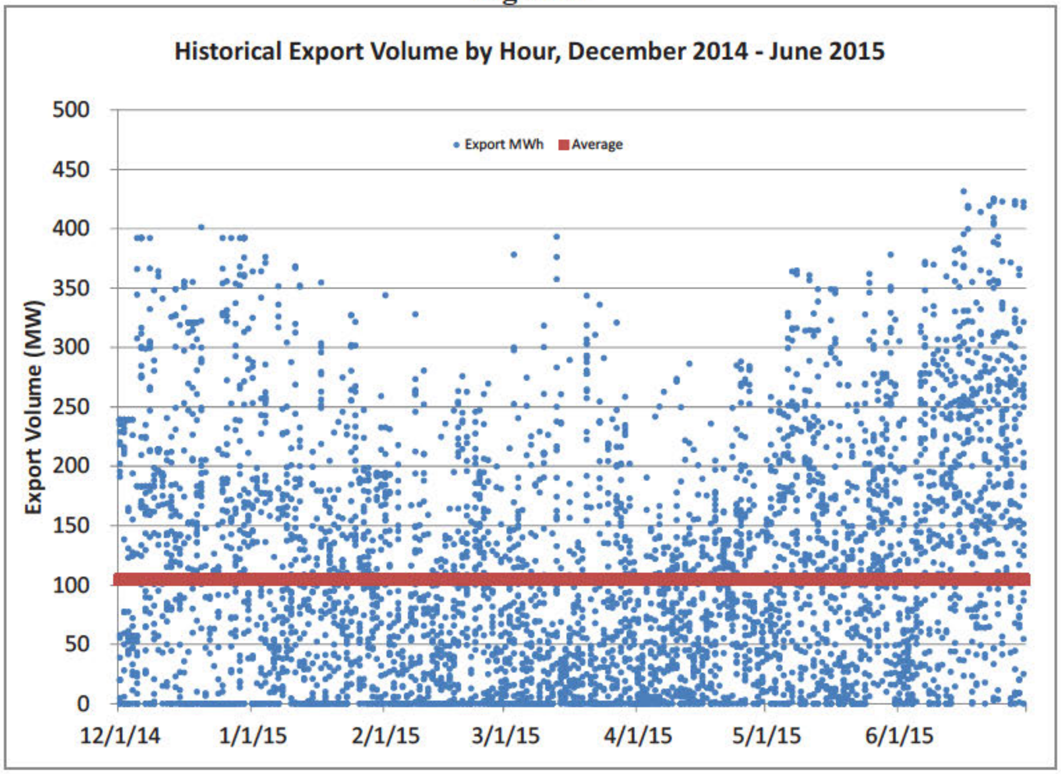
Q. How much additional export volume has ICNU proposed?

A. The Company's Initial Filing included an average of 109 MW of EIM exports to CAISO, utilizing 41 percent of the 264 MW of transmission available for EIM transfers. ICNU's proposal assumes an average of nearly 550 MW of EIM exports over approximately based on a 33 percent utilization of nearly 1,600 MW of total transfer capability.

Q. How do the Company's resources available to support EIM exports compare to ICNU's assumed exports?

A. The Company's Initial Filing included an average regulation requirement of approximately 560 megawatts. As shown in Figure 4, EIM exports to the CAISO have varied widely between December 2014 and June 2015. More than 20 percent of all hours had less than 10 MW of EIM exports, while the Company's maximum hourly exports were over 400 MW. Additional transmission capacity will go unused if the existing capacity isn't fully utilized, whereas the Company's exports cannot exceed the resources it has available. Clearly, the Company's resources available to support EIM exports in the forecast period are insufficient to support exports of up to 1,600 MW, and additional transmission capacity will go unused.

Figure 4



Q. Did the original E3 benefit study of the PacifiCorp-CAISO EIM benefit projections indicate diminishing returns from incremental transmission capability?

A. Yes. The E3 study of the PacifiCorp-CAISO EIM assessed benefits at three transfer levels: 100, 400, and 800 MW. A 400 percent increase in transfer capability from 100 to 400 MW resulted in roughly 50 percent more inter-regional dispatch benefits. An additional 200 percent increase in transfer capability from 400 to 800 MW resulted in a minimal increase in inter-regional benefits.

Q. Do the Company's existing EIM results indicate diminishing returns with incremental transmission availability?

A. Yes. In April 2015, the transmission available for EIM exports was roughly one-third less than in any other month. Yet the total export value was in line with the results from December 2014 through May 2015. This indicates that the additional transmission might not have provided much additional benefit. If the Company had made more transmission available for EIM transfers in April, the average April export margin would likely have dropped to a level more in line with the other months.

Q. Would any of ICNU's other proposed adjustments impact the regulation resources available for EIM?

A. Yes. ICNU has proposed that the Company's regulation requirement be reduced to just 316 MW. This frees up the Company's least-cost generation for hourly sales, reducing NPC, but leaves a smaller volume of higher-cost generation available to support EIM transactions. Export volumes would necessarily be lower under those circumstances, and the margin on export transactions would also be lower. ICNU's proposed adjustments double count the benefits associated with dispatch of a significant portion of the Company's resources.

Q. Even if the Company has additional resources available at the same marginal cost, and additional transfers to CAISO become possible, will the Company earn the same margin?

A. No. The Company's export revenues are based on the marginal resource dispatched, as this resource sets the market price. If additional volumes are transferred to CAISO, the CAISO will back down its highest cost resource, leaving lower cost resources on the margin and reducing the market price. This not only results in lower revenues on the additional export volumes, it also reduces the revenues on the existing export volumes. This result is somewhat apparent in the inter-regional EIM benefit results estimated by E3. The inter-regional EIM benefits were highest for the

PacifiCorp-CAISO EIM. The addition of NV Energy resulted in incremental benefits of just 21 percent of the PacifiCorp-CAISO total. The addition of APS and PSE resulted in incremental benefits to existing participants of just five percent and two percent, respectively.

Q. Will the Company always benefit from the addition of new participants?

A. Not necessarily. If new participants have lower cost resources than the Company, they may be selected instead of the Company's resources, and the Company's export volumes and benefits would go down. The Company would remain better off by participating in EIM, as it would also be able to import lower cost resources from the new participant, but its overall benefits could be lower than under the smaller EIM footprint.

Q. What is the second issue with ICNU's proposal for increased benefits with the addition of NV Energy?

A. ICNU overstates the transmission capability available to support EIM transfers between PacifiCorp's East BAA and NV Energy. First, ICNU's proposal is based on the maximum transfer capability NV Energy identified that it expected to make available for EIM. NV Energy indicated, however, that this capacity would be adjusted based on the schedules on those paths. The available transfer capability (ATC) across these paths posted on NV Energy's OASIS website is a better indicator of the transmission that will actually be available to support EIM transfers.

Second, transfers to or from NV Energy also require a path to the point of interconnection from the Company's regulating resources and loads, so transfers may also be limited by the Company's ATC within its East BAA. When the NV Energy and PacifiCorp transmission limits are taken together, the result is slightly lower than the level proposed by ICNU.

Finally, the Company does not currently have long-term rights to either the Mona or Mead markets modeled in GRID. Transactions at these markets will require transfer capability that has not yet been reserved, and is not reflected in the posted available volumes. The Company's Initial Filing adjusted the EIM transfer capability from the Company's West BAA to the CAISO for sales transactions in the COB market. A similar adjustment for forecasted sales at the Mona and Mead markets is appropriate here. This reduces the transmission available for EIM by roughly one-third.

Q. What is the resulting EIM transfer capability from the Company's East BAA to NV Energy?

A. In the forecast period the resulting EIM transfer capability from the Company's East BAA to NV Energy averages 244 MW.

Q. Is it reasonable that the inter-regional dispatch benefits associated with the addition of NV Energy are larger than those associated with PSE and APS?

A. Yes. Much of the inter-regional benefits of EIM are associated with displacing relatively high-cost CAISO generation. The addition of NV Energy to the EIM creates a new path to reach CAISO, and additional displacement of relatively high-cost CAISO generation. PSE and APS do not provide PacifiCorp incremental transmission to the California market, and their own generation costs are likely to be more in line with the Company's costs. For the reasons described previously, it is possible that the addition of PSE and APS may even reduce the Company's overall

EIM inter-regional benefits. Given the uncertainty and limited duration in the forecast period, however, the Company believes allocating a share of the E3 results is reasonable.

Response to CUB's EIM Inter-regional Dispatch Benefit Proposal

Q. Does the Company support CUB's proposal to defer the inter-regional dispatch benefits outside of the PCAM until next year's TAM?

A. No. CUB expresses concern that the Company's forecast of EIM benefits in its Initial Filing is based on only two months of historical data, and that the limited data does not include benefits of the EIM in summer months.[62] As described above, the Company has incorporated additional historical data in the Reply Update, and intends to include a full summer of actual results in the Final Update. This means that when the Company files its 2017 TAM, only four additional months of historical EIM data will be available.

Q. Do you agree with CUB that any forecast of the EIM inter-regional dispatch benefits is unreliable because of lack of historical data and that this lack of reliability supports separate, dollar-for-dollar treatment?

A. No. The ability to forecast inter-regional dispatch benefits is no more unreliable than the ability to forecast renewable resource generation and market prices, which are likewise uncertain and out of the Company's control. It is inconsistent for CUB to oppose the use of historical data for improving the forecast of system balancing costs in this case, but object to the Company's modeling of EIM benefits based on the dearth of historical data. And it is inconsistent for CUB to propose separate tracking

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

of EIM benefits in this case, while rejecting the utilities' proposal in docket UM 1662 for separate tracking of renewable energy variances.[63]

Q. Is it clear how to carve out the actual EIM benefits from the PCAM for later true-up to the forecast?

A. No. CUB's testimony references the entire, total company EIM benefit of $9.4 million included in the Company's Initial Filing and recommends that the difference between the forecast and actual benefits be removed from the PCAM. The $9.4 million of benefits includes inter-regional benefits as well as the reserve diversity benefit (i.e. a lower reserve requirement included in the GRID model). The cost of reserves, or benefit of holding fewer reserves, is not specifically identified in actual NPC results and would be difficult to quantify for later true up.

Hermiston Purchase Expiration

Q. Please describe the Hermiston power purchase agreement (PPA).

A. The Hermiston Power Project is a gas-fired generating plant. In 1993, the Company entered into a PPA to purchase the entire output of the plant. The next year, the Company exercised its option to purchase a 50 percent interest in the plant. Therefore, the Company now owns 50 percent of the plant and has a PPA for the other 50 percent of the plant's output.

On June 30, 2016, the PPA for the output of the 50 percent share of the Hermiston plant not owned by the Company terminates. The PPA included an option to extend the contract, which, [redacted]

[63] *In the Matter of Portland General Electric and PacifiCorp dba Pacific Power Request for Generic Power Cost Adjustment Mechanism Investigation*, Docket No. UM 1662, Reply Testimony of the Citizens' Utility Board (May 11, 2015).

[redacted]. Thus, beginning on July 1, 2016, the NPC forecast includes only the Company's 50 percent ownership share of the Hermiston plant.

Q. Does ICNU raise a concern about the Company's modeling of the Hermiston plant?

A. Yes. ICNU argues that the Company was imprudent in choosing not to exercise its option to extend the PPA.[64]

Q. What is the basis for ICNU's argument?

A. ICNU's criticism is largely based on the Company's IRP modeling. ICNU basically alleges that the Company cannot use east-side resources to meet the west-side's winter peak due to transmission constraints between the east and west sides of PacifiCorp's system. Based on this claim, ICNU argues that the Company acted imprudently when it chose not to extend the Hermiston PPA without specifically analyzing the winter peaking benefits of the Hermiston PPA.

Q. Does ICNU propose a specific adjustment related to the Hermiston PPA?

A. No. ICNU simply recommends that the Commission find that the decision not to extend the PPA was imprudent.

Q. Is there any merit to ICNU's criticisms?

A. No. The Company's analysis supporting the decision not to extend the PPA appropriately balanced the specific costs and benefits of the Hermiston PPA based on

[64] ICNU/100, Mullins/42.

what the Company knew at the time that it made its decision. The contract was very expensive for capacity that is not needed on either the east or the west in the next few years. Furthermore, inclusion of the PPA for the last six months of 2016 in this TAM filing would increase NPC by approximately $3.0 million. ICNU's contention that the resource may prove useful at some undetermined future time is simply speculation that lacks evidentiary support.

Moreover, ICNU's adjustment is fundamentally based on a conclusion that the Company's IRP modeling only assesses the requirements needed to meet the system peak in the summer. In fact, the IRP process incorporates the impacts associated with the west-side winter peak at least twice in the development of a preferred portfolio.

Q. How does the IRP incorporate west-side winter peak requirements?

A. First, the Company's planning reserve margin of 13 percent is selected based on a series of stochastic loss of load studies. These studies estimate the unserved load for each hour of the forecast period, not just for the summer peak, so they would capture shortages during the west-side winter peak. The selection of a 13 percent planning margin meets 10 year planning targets at the lowest reasonable cost, and covers all periods, not just the summer peak.

Second, unserved load is also evaluated in the Company's preferred portfolio selection. Resource portfolios which failed to provide adequate supply to meet the Company's west-side winter peak would be noted at this step and modeling changes would be necessary to address this issue. Such adjustments were not necessary in the Company's most recent IRP.

These aspects of the Company's IRP modeling, and the modeling on which the Hermiston PPA decision was based, have never been criticized by the Commission in an IRP proceeding.

Q. If the Commission decides that the Company was imprudent in not renewing the PPA, should NPC continue to reflect the cost reductions associated with non-renewal?

A. No. NPC should reflect the non-renewal benefits only if the Commission rejects ICNU's proposal that the Company's decision be deemed imprudent. In discovery, ICNU appeared to agree with this position.[65]

Q. Does ICNU have any other concerns regarding the Hermiston PPA?

A. Yes. ICNU recommends an adjustment to disallow the costs of the point-to-point transmission that will no longer be used once the Hermiston PPA expires.[66] ICNU claims that the Company renewed the full capacity of the transmission contract after it had decided not to extend the Hermiston PPA.[67] ICNU's adjustment results in a reduction to NPC of approximately $54,000.

Q. Are there any errors in ICNU's adjustment?

A. Yes. ICNU's adjustment is based on one month of transmission expense rather than the total expense in the forecast period. The associated transmission expense during the six months after the termination of the Hermiston PPA actually totals approximately $650,000.

[65] *See* Exhibit PAC/508, ICNU Response to PacifiCorp Data Request No. 13.
[66] ICNU/100, Mullins/42.
[67] ICNU/100, Mullins/43.

Q. How do you respond to this adjustment?

A. Contrary to ICNU's claim, the Company was required to enter into the transmission contract before it decided whether to extend the Hermiston PPA. The Company was required to submit a request for renewal of the BPA transmission contract one year in advance of its termination. Since the transmission contract terminated at the end of September 2014, the Company elected to renew the contract in September 2013. To maintain roll-over rights, the Company was required to enter into a contract with a five-year term.

More importantly, however, even with the expiration of the Hermiston PPA, the transmission contract will still be used and useful. This transmission path allows for transfer of resources other than Hermiston, and the maximum amount is utilized at times in the Company's forecast even after the Hermiston PPA expires. Moreover, the transmission path is constrained and there is no certainty that the same transmission capacity could be acquired at a later date.

Outage Rate Modeling

Q. Please describe the Company's proposed refinement to its outage rate modeling.

A. In this case, the Company modeled thermal plant forced outages and unit de-rates as discrete events, rather than applying a uniform de-rate to the plant operating characteristics across all hours. In addition, because outages are no longer modeled as de-rates, the Company removed the corresponding adjustments to heat rates and minimum operating levels.

Q. Does ICNU object to the Company's modeling change?

A. Yes. ICNU recommends that the Company continue to use the methodology adopted by the Commission in docket UM 1355, which would reduce NPC by $0.2 million.[68] Notably, in recent testimony filed in the Company's current Wyoming general rate case, Mr. Mullins accepted the Company's outage modeling methodology with only one change to cap long outages at 28 days.[69] This nuance is already reflected in the Company's Oregon proposal in this proceeding.

Q. What is the basis for ICNU's adjustment?

A. ICNU contends that the Company's modeling results in more frequent, smaller outages that are not representative of the Company's actual operations and will increase outage costs due to the expensive costs of ramping resources up and down in response to frequent outages. ICNU also claims that the Company's modeling is not normalized because its use of historical data includes costly outages during winter peaks. Finally, ICNU argues against adopting a change in the outage rate modeling in this TAM because it will lack the extensive review that took place in docket UM 1355.

Q. How do you response to ICNU's adjustment?

A. First, I disagree with ICNU's claim that the Company's modeling is deficient. As described in my direct testimony, the pattern of outages proposed by the Company is a dramatically better simulation of the Company's actual outage patterns than the existing methodology, which assumes every single plant will be partially available in every single hour.

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[68] ICNU/100, Mullins/43.
[69] Docket No. 20000-469-ER-15, WIEC/301, Mullins/67.

Second, while the Company's proposal does shorten the length of outages, it also eliminates outages that are less than two hours long. As a result, roughly 12 percent of these short outage events in the historical period were eliminated.

Third, ICNU's claim that more frequent outages are more costly is generally correct in the real world, but that is not necessarily the case in GRID. ICNU suggests that the Company's natural gas plant commitment will be affected by the short duration of outages but ignores the reality the Company does not know an outage will begin the next day, whereas in the GRID screening process employed in the forecast, resource commitment can be adjusted to account for the known impacts of outages.

Fourth, as I describe in my direct testimony, the Commission acknowledged that the methodology adopted in docket UM 1355 was imperfect and that parties should explore refinements in future NPC cases. There is no merit to the argument that changes in outage rate modeling may occur only in the context of a generic investigation like docket UM 1355.

Wind Modeling

Q. Please describe the Company's refinements to its modeling of wind generation.

A. The Company made two changes to modeling the output of wind generators. First, the Company reduced generation output at its Glenrock and Seven Mile Hill wind sites to reflect expected energy lost from compliance curtailment for avian protection.

Second, the Company modeled generation from the Company's wind PPAs to match the levels in the 48-month historical period. 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.

Q. Does ICNU object to these modeling refinements?

A. Yes. ICNU proposes adjustments to both of these modeling changes.

Q. Please describe ICNU's avian protection adjustment.

A. ICNU argues that the Company should be required to use the modeling assumptions that were originally used to justify the wind facilities, claiming that were "controversial."[70] ICNU also claims that the modeling adjustment is immaterial. ICNU's adjustment decreases NPC by approximately $52,000.

Q. How do you respond to ICNU's adjustment?

A. The Commission has never required a company to model a generation resource based only on the cost assumptions made at the time that the resource was acquired and ICNU provides no legitimate reason for the Commission to do so here. Indeed, the Commission has specifically rejected ICNU's recommendation. In the very same docket, ICNU cites for the proposition that the Commission should use planning assumptions to set rates, the Commission said:

> 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.[71]

Q. Is ICNU's proposal here consistent with its prior positions?

A. No. Not only is ICNU's recommendation contrary to clear Commission precedent, it is also directly contrary to ICNU's position in other cases. In PGE's docket UE 286, PGE assumed a capacity factor for the Tucannon River wind project based on the

[70] ICNU/100, Mullins/45.
[71] *Re PacifiCorp 2009 Renewable Adjustment Clause Schedule 202*, Docket No. UE 200, Order No. 08-548 at 21 (Nov. 14, 2008).

assumed capacity factor PGE used in its Request for Proposal process. Mr. Mullins' objected to this approach and proposed a higher capacity factor "based on the most up-to-date information known at this time."[72] Mr. Mullins argued that using the "outdated" capacity factor PGE proposed would mean that "customers will not receive the benefit of apparent improvements" in the plants' expected capacity factor.[73]

Q. Are there any other reasons to reject ICNU's recommendation?

A. Yes. The Company's modeling change relates to the cost of compliance with federal environmental laws. As to the materiality issue, the Commission has never set a materiality threshold for forecasting rates. In any event, the modeling change proposed here by the Company is of the same magnitude as ICNU's Hermiston transmission adjustment in this case.

Q. Please describe ICNU's adjustment to the refined wind PPA modeling.

A. ICNU recommends eliminating this modeling change, reducing NPC by $1.4 million. ICNU again argues that the wind generation used to forecast PPA costs should be the generation assumed at the time that the Company entered into the PPA.

Q. How do you respond to this argument?

A. As described above, ICNU's adjustment is unprecedented and has no basis in NPC forecasting. Every time the Company acquires a resource, whether a PPA or a Company-owned resource, there are assumptions made regarding the expected

[72] *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.
[73] *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.

resource performance. But the Commission has never, as a general policy, required all future NPC forecasting to use the same assumptions used to acquire the resource.

Q. ICNU also claims that four years is too short a time period to normalize wind output. Do you agree?

A. No. A four-year history is a more robust basis for modeling wind generation in the TAM than the pre-acquisition forecast ICNU recommends. In addition, based on the projects that have additional history, the outcome does not significantly change when additional historical data is used.

Q. Did ICNU recently stipulate to use of a five-year rolling average to forecast PGE's wind generation?

A. Yes. In docket UE 266, ICNU stipulated to PGE's use of a five-year rolling average to forecast wind generation in that case.[74] It is my understanding that PGE continues to use a five-year rolling average and ICNU has not objected to its continued use.[75] ICNU has made no attempt to reconcile its objection to PacifiCorp's use of a four-year average in this case with its support for PGE's use of a five-year average in docket UE 266.

[74] *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).
[75] *See e.g.*, *Portland General Electric Co., Request for a General Rate Revision*, Docket No. UE 283, PGE/500, Niman-Peschka-Hager/28 (describing the use of five-year rolling average to forecast generation at Biglow and Tucannon). Mr. Mullins' NPC testimony in docket UE 286, which was the NPC carve-out docket from docket UM 283, did not challenge the wind generation modeling.

Direct Access

Q. Noble Solutions recommends that the Schedule 294, 295 and 296 transition adjustments be adjusted to reflect the value of freed-up Renewable Energy Certificates (RECs) resulting from the departure of the direct access load.[76] How do you respond to this recommendation?

A. This recommendation should be rejected. The underlying assumption in this adjustment is that the Company sells RECs that are freed up once its load decreases due to departing direct access customers. This assumption is untrue. The Company currently does not sell its Oregon-allocated RECs. Because Oregon allows unlimited banking, the Company banks the unused RECs and uses them for future compliance.

Q. Has the Commission previously rejected similar adjustments proposed by Noble Solutions purporting to capture the value of freed-up assets?

A. Yes. Noble Solutions' recommendation is conceptually similar to its prior recommendation that direct access customers receive a credit for the value of freed-up transmission resulting from the departure of direct access loads. The Commission has rejected that adjustment three times.[77] Most recently, in docket UE 267, the Commission again "rejected potential transition adjustment credits for the resale of BP A transmission," finding "no compelling evidence of PacifiCorp's actual ability to sell BPA transmission rights when direct access loads depart and then repurchase such rights when direct access loads returns."[78] Here, Noble Solutions has likewise

[76] Noble Solutions/100, Higgins/15.
[77] Order No. 12-409 at 17; Order No. 13-387 at 13-14; *Re PacifiCorp Transition Adjustment, Five-Year Cost of Service Opt-Out*, Docket No. UE 267, Order No. 15-060 at 9 (Feb. 24, 2015), *reconsideration denied*, Order No. 15-195 (June 16, 2015).
[78] Order No. 15-060 at 9.

failed to produce compelling evidence that the Company will actually be able to sell RECs freed-up by departing direct access load.

Q. Even if the Company were able to sell freed-up RECs, is there any reason to include that revenue as a transition credit?

A. No. To the extent the Company generates revenues from selling RECs, those revenues are passed back to all customers through the property sales balancing account. Thus, departing direct access customers will receive a share of the benefits of those sales, if they should occur.

Q. Noble Solutions also recommends that the Consumer Opt-Out Charge included in the Company's Five-Year Transition Adjustment should decrease, rather than increase, in years 6 through 10. How do you respond?

A. The Company opposes this proposal. The Commission rejected this recommendation in docket UE 267 and Noble Solutions has presented no compelling reason for the Commission to change its position here.

Q. Is the Company's proposed Consumer Opt-Out Charge here consistent with the Commission's order in docket UE 267?

A. Yes. In docket UE 267, the Commission approved the Consumer Opt-Out Charge "as it was presented in modified form by PacifiCorp in reply testimony."[79] Like the Company's filing in docket UE 267, the proposed Consumer Opt-Out Charge here properly escalates the Company's fixed generation costs at the average rate of inflation—meaning that, in real terms, the fixed generation costs are held constant

[79] Order No. 15-060 at 6.

through year 10. This is a conservative assumption and one that is consistent with the Commission's order in docket UE 267.

Q. Did Noble Solutions challenge the Company's proposal to escalate the fixed generation costs at the average rate of inflation in docket UE 267?

A. Noble Solutions did not challenge this proposal in testimony in docket UE 267. But in its briefing, Noble Solutions (along with the other stipulating parties), argued that the "revenue requirement component of the stranded cost calculation should decline over time" and that PacifiCorp's proposed Consumer Opt-Out Charge was "fatally flawed" because it "assumes that the revenue requirement of the stranded assets will escalate from the current fixed Schedule 200 charge at the rate of inflation . . ."[80] This is the same argument made by Noble Solutions here.

Q. How did the Commission resolve Noble Solutions recommendation in docket UE 267?

A. The Commission did not specifically address this issue in Order No. 15-060 approving PacifiCorp's Consumer Opt-Out Charge. But the Commission's approval of the Consumer Opt-Out Charge "as it was presented in modified form by PacifiCorp in reply testimony" rejected Noble Solutions' recommendation.[81]

Q. Did Noble Solutions ask the Commission to reconsider its decision rejecting the recommendation to decrease the Consumer Opt-Out Charge in years six through 10?

A. Yes. Noble Solutions, along with several other parties, sought reconsideration or

[80] *Re PacifiCorp's Transition Adjustment, Five-Year Cost of Service Opt-Out*, Docket No. UE 267, Joint Post-Hearing Brief of Stipulating Parties at 11 (July 28, 2014).
[81] Order No. 15-060 at 6.

rehearing, arguing:

> the portion of the Consumer Opt-Out Charge that includes an assumed Schedule 200 cost responsibility for direct access customers in years six through 10 (after the date of the opt-out election) must be limited to a proper depreciated value of the Schedule 200 assets. Calculation of the Consumer Opt-Out Charge may not assign to direct access customers responsibility for an asset value that escalates at 1.9 percent as set forth in PacifiCorp's exhibit.[82]

Q. How did the Commission decide Noble Solutions' request that the Commission reverse its approval of PacifiCorp's proposed Consumer Opt-Out Charge?

A. In Order No. 15-195, the Commission rejected Noble Solutions' request, noting that the Commission "adequately addressed and resolved all of the issues necessary to develop PacifiCorp's Five-Year Program."[83] Thus, in Order No. 15-195, the Commission specifically rejected Noble Solutions' recommendation.

When denying Noble Solutions' petition for reconsideration, the Commission made clear that if parties wanted to challenge how the Consumer Opt-Out Charge was calculated in the future, they must have new evidence or arguments to do so.[84]

Q. Does Noble Solutions' testimony here include any new evidence or arguments?

A. No. Noble Solutions presents no new evidence or arguments. Therefore, its recommendation should be rejected.

Q. Does this conclude your reply testimony?

A. Yes.

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[82] *Re PacifiCorp's Transition Adjustment, Five-Year Cost of Service Opt-Out*, Docket No. UE 267, Joint Parties' Motion for Clarification or, in the Alternative, Application for Reconsideration Or Rehearing at 18 (Apr. 20, 2015).
[83] *Re PacifiCorp's Transition Adjustment, Five-Year Cost of Service Opt-Out*, Docket No. UE 267, Order No. 15-195 at 2 (June 16, 2015).
[84] Order No. 15-195 at 3.

Docket No. UE 296
Exhibit PAC/501
Witness: Brian S. Dickman

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Reply Testimony of Brian S. Dickman

Oregon-Allocated Net Power Costs

August 2015

PacifiCorp
CY 2016 TAM

Line no		ACCT.	Total Company: UE-287 Final TAM CY 2015	Total Company: TAM CY 2016	Total Company: Reply Update CY 2016	Factor	Factors CY 2015	Factors CY 2016	Oregon Allocated: UE-287 Final TAM CY 2015	Oregon Allocated: TAM CY 2016	Oregon Allocated: Reply Update CY 2016
1	**Sales for Resale**										
2	Existing Firm PPL	447	14,460,450	14,516,523	14,842,118	SG	25.687%	25.464%	3,714,489	3,696,443	3,779,351
3	Existing Firm UPL	447	29,139,801	26,803,485	26,803,485	SG	25.687%	25.464%	7,485,207	6,825,157	6,825,157
4	Post-Merger Firm	447	414,915,695	376,599,095	349,727,494	SG	25.687%	25.464%	106,580,340	95,896,037	89,053,535
5	Non-Firm	447	-	-	-	SE	24.484%	24.074%	-	-	-
6	**Total Sales for Resale**		458,515,946	417,919,102	391,373,096				117,780,036	106,417,637	99,658,043
7											
8	**Purchased Power**										
9	Existing Firm Demand PPL	555	3,538,604	4,635,674	4,846,373	SG	25.687%	25.464%	908,969	1,180,414	1,234,066
10	Existing Firm Demand UPL	555	52,672,295	53,565,725	52,853,542	SG	25.687%	25.464%	13,530,052	13,639,812	13,458,463
11	Existing Firm Energy	555	28,521,106	33,338,675	33,514,101	SE	24.484%	24.074%	6,983,099	8,026,082	8,068,315
12	Post-merger Firm	555	537,557,343	535,787,067	534,397,710	SG	25.687%	25.464%	138,083,579	136,431,173	136,077,392
13	Secondary Purchases	555	-	-	-	SE	24.484%	24.074%	-	-	-
14	Other Generation Expense	555	3,522,855	6,262,777	6,450,452	SG	25.687%	25.464%	904,924	1,594,734	1,642,523
15	**Total Purchased Power**		625,812,203	633,589,918	632,062,178				160,410,624	160,872,215	160,480,759
16											
17	**Wheeling Expense**										
18	Existing Firm PPL	565	27,165,030	21,064,818	21,008,517	SG	25.687%	25.464%	6,977,943	5,363,880	5,349,544
19	Existing Firm UPL	565	-	-	-	SG	25.687%	25.464%	-	-	-
20	Post-merger Firm	565	112,170,725	118,768,709	119,126,778	SG	25.687%	25.464%	28,813,550	30,242,899	30,334,077
21	Non-Firm	565	6,904,205	8,415,001	8,466,629	SE	24.484%	24.074%	1,690,424	2,025,860	2,038,289
22	**Total Wheeling Expense**		146,239,960	148,248,527	148,601,924				37,481,916	37,632,640	37,721,910
23											
24	**Fuel Expense**										
25	Fuel Consumed - Coal	501	760,067,707	766,272,808	758,188,415	SE	24.484%	24.074%	186,094,753	184,475,497	182,529,229
26	Fuel Consumed - Coal (Cholla)	501	60,047,431	58,220,045	54,005,282	SSECH/SE	24.484%	24.074%	14,701,995	14,016,120	13,001,442
27	Fuel Consumed - Gas	501	3,732,974	5,004,816	4,792,819	SE	24.484%	24.074%	913,980	1,204,879	1,153,842
28	Natural Gas Consumed	547	333,797,813	334,547,426	321,427,241	SE	24.484%	24.074%	81,726,958	80,540,249	77,381,645
29	Simple Cycle Comb. Turbines	547	5,273,378	4,853,712	4,108,614	SSECT/SE	24.484%	24.074%	1,291,132	1,168,501	989,124
30	Steam from Other Sources	503	4,328,145	4,797,463	4,836,760	SE	24.484%	24.074%	1,059,702	1,154,960	1,164,420
31	**Total Fuel Expense**		1,167,247,450	1,173,696,270	1,147,359,131				285,788,521	282,560,207	276,219,701
32											
33	**Net Power Cost (Per GRID)**		1,480,783,666	1,537,615,613	1,536,650,137				365,901,025	374,647,425	374,764,328
34											
35											
36	Settlement Adjustment		(1,300,000)			SG	25.687%	25.464%	(333,934)		
37	EIM Benefits*		(6,700,000)			SG	25.687%	25.464%	(1,721,044)		
38	Oregon Situs Solar		(141,066)	(131,143)	436,024	OR	100.000%	100.000%	(141,066)	(131,143)	436,024
39	**Total NPC Net of Adjustments**		1,472,642,600	1,537,484,470	1,537,086,161				363,704,981	374,516,282	375,200,352
40											
41	EIM Costs		6,700,000	4,612,380	4,617,264	SG	25.687%	25.464%	1,721,044	1,174,482	1,175,726
42	**Total TAM Net of Adjustments**		1,479,342,600	1,542,096,849	1,541,703,425				365,426,026	375,690,764	376,376,077
43											
44									Increase Absent Load Change	10,264,739	10,950,052
45											
46								Oregon-allocated NPC Baseline in Rates from UE-287	$365,426,026		
47								$ Change due to load variance from UE-287 forecast	822,040		
48								2016 Recovery of NPC in Rates	$366,248,066		
49	*EIM Benefits for the 2016 TAM are reflected in net power costs										
50									**Increase Including Load Change**	**9,442,698**	**10,128,012**
51											
52									Add Other Revenue Change	2,309,696	2,308,753
53											
54									**Total TAM Increase**	**11,752,395**	**12,436,765**

Docket No. UE 296
Exhibit PAC/502
Witness: Brian S. Dickman

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Reply Testimony of Brian S. Dickman

Net Power Costs Report

August 2015

PacifiCorp

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Net Power Cost Analysis

12 months ended December 2016	01/16-12/16	Jan-16	Feb-16	Mar-16	Apr-16	May-16	Jun-16	Jul-16	Aug-16	Sep-16	Oct-16	Nov-16	Dec-16
						$							
Special Sales For Resale													
Long Term Firm Sales													
Black Hills s27013/s28160	14,842,118	1,252,809	1,205,923	1,244,377	1,225,703	1,245,723	1,223,787	1,248,645	1,245,840	1,234,979	1,235,075	1,225,030	1,254,226
BPA Wind s42818	2,631,751	334,752	288,687	279,742	194,794	187,665	172,685	115,191	111,139	117,826	238,821	295,404	295,045
Hurricane Sale s393046	12,152	1,013	1,013	1,013	1,013	1,013	1,013	1,013	1,013	1,013	1,013	1,013	1,013
LADWP (IPP Layoff)	26,803,485	2,259,411	1,894,946	1,769,697	1,189,888	2,237,017	2,568,975	2,658,253	2,657,940	2,534,044	2,545,057	2,136,582	2,351,676
Leaning Juniper Revenue	95,223	5,599	5,789	8,728	6,827	7,466	7,826	11,212	11,699	9,573	7,696	6,168	6,639
NVE s811499	-	-	-	-	-	-	-	-	-	-	-	-	-
Pacific Gas & Electric s524491	-	-	-	-	-	-	-	-	-	-	-	-	-
PSCO s100035	-	-	-	-	-	-	-	-	-	-	-	-	-
Salt River Project s322940	-	-	-	-	-	-	-	-	-	-	-	-	-
SCE s513948	-	-	-	-	-	-	-	-	-	-	-	-	-
SDG&E s513949	-	-	-	-	-	-	-	-	-	-	-	-	-
Shell Sale 2013-2014	-	-	-	-	-	-	-	-	-	-	-	-	-
SMUD s24296	-	-	-	-	-	-	-	-	-	-	-	-	-
UMPA II s45631	9,609,582	593,283	572,367	593,283	582,825	593,283	932,517	1,779,848	1,400,150	792,640	593,283	582,825	593,283
Total Long Term Firm Sales	53,994,310	4,446,866	3,968,725	3,896,839	3,201,049	4,272,165	4,906,802	5,814,160	5,427,782	4,690,074	4,620,944	4,247,021	4,501,882
Short Term Firm Sales													
COB	-	-	-	-	-	-	-	-	-	-	-	-	-
Colorado	-	-	-	-	-	-	-	-	-	-	-	-	-
Mead	-	-	-	-	-	-	-	-	-	-	-	-	-
Mid Columbia	-	-	-	-	-	-	-	-	-	-	-	-	-
Mona	-	-	-	-	-	-	-	-	-	-	-	-	-
NOB	-	-	-	-	-	-	-	-	-	-	-	-	-
Palo Verde	14,701,790	4,421,040	4,459,890	4,751,160	1,069,700	-	-	-	-	-	-	-	-
SP15	-	-	-	-	-	-	-	-	-	-	-	-	-
Utah	-	-	-	-	-	-	-	-	-	-	-	-	-
Washington	-	-	-	-	-	-	-	-	-	-	-	-	-
West Main	-	-	-	-	-	-	-	-	-	-	-	-	-
Wyoming	-	-	-	-	-	-	-	-	-	-	-	-	-
Electric Swaps Sales	-	-	-	-	-	-	-	-	-	-	-	-	-
STF Index Trades	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Short Term Firm Sales	14,701,790	4,421,040	4,459,890	4,751,160	1,069,700	-	-	-	-	-	-	-	-
System Balancing Sales													
COB	18,201,393	3,779,899	1,058,073	942,585	749,662	687,155	816,964	1,080,643	2,055,578	2,165,263	1,570,891	1,899,927	1,394,754
Four Corners	48,776,980	4,616,623	2,988,886	3,938,490	3,420,501	2,873,984	2,532,141	3,395,772	5,572,168	4,485,495	6,205,305	4,553,006	4,194,612
Mead	28,078,357	2,493,833	1,306,826	1,662,758	1,686,945	1,333,146	1,624,795	3,084,323	2,548,795	2,977,125	2,763,992	3,197,539	3,398,282
Mid Columbia	23,575,059	4,061,279	707,255	5,272,784	3,457,673	570,463	801,108	1,113,877	1,851,737	2,482,037	1,801,976	955,214	499,656
Mona	19,631,543	1,935,386	369,564	527,661	1,817,530	2,967,313	1,752,659	1,230,718	1,196,977	2,518,212	1,478,295	1,956,375	1,880,852
NOB	-	-	-	-	-	-	-	-	-	-	-	-	-
Palo Verde	102,497,331	5,778,509	6,041,531	5,545,476	8,133,610	8,267,330	9,498,028	9,110,055	7,667,387	11,823,632	11,016,632	10,691,907	8,923,236
EIM Exports	9,594,729	427,889	507,281	589,543	616,749	747,444	1,335,624	1,393,872	1,239,988	955,634	595,669	496,873	688,163
Trapped Energy	319,031	-	-	-	-	2,343	300,409	-	-	2,695	-	13,584	-
DA-RT Balancing	72,002,572	5,587,802	4,211,690	5,795,903	4,644,192	5,795,036	5,497,583	9,179,115	10,084,732	5,229,790	5,196,679	4,675,932	6,104,117
Total System Balancing Sales	322,676,996	28,681,218	17,191,105	24,275,200	24,526,862	23,244,213	24,159,311	29,588,376	32,217,359	32,639,882	30,629,439	28,440,357	27,083,674
Total Special Sales For Resale	391,373,096	37,549,125	25,619,720	32,923,199	28,797,611	27,516,379	29,066,113	35,402,536	37,645,141	37,329,956	35,250,383	32,687,378	31,585,555

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Net Power Cost Analysis

Purchased Power & Net Interchange

12 months ended December 2016	01/16-12/16	Jan-16	Feb-16	Mar-16	Apr-16	May-16	Jun-16	Jul-16	Aug-16	Sep-16	Oct-16	Nov-16	Dec-16
Long Term Firm Purchases													
APS Supplemental p27875	779,511	64,796	116,880	181,434	86,148	-	-	-	-	92,592	-	120,528	117,134
BPA Reserve Purchase	-	-	-	-	-	-	-	-	-	-	-	-	-
Combine Hills Wind p160595	5,226,273	414,665	462,908	560,424	551,989	467,464	487,360	400,205	385,055	298,718	361,361	419,818	416,305
Deseret Purchase p194277	36,415,346	3,104,118	3,017,274	3,017,274	3,060,696	2,626,470	3,060,696	3,104,118	3,104,118	3,060,696	3,104,118	3,051,650	3,104,118
Douglas PUD Settlement p38185	2,397,018	114,625	92,145	197,025	314,425	366,091	361,141	310,994	235,028	106,360	98,389	100,858	99,937
Eagle Mountain - UAMPS/UMPA	2,345,405	170,313	147,648	136,668	141,681	186,673	214,334	294,494	256,477	241,718	184,908	152,777	217,714
Gemstate p99489	3,191,800	261,000	257,700	261,800	257,700	257,700	257,700	257,700	276,000	257,700	280,200	305,600	261,000
Georgia-Pacific Camas	-	-	-	-	-	-	-	-	-	-	-	-	-
Hermiston Purchase p99563	36,602,131	6,637,952	6,445,388	6,658,388	6,294,328	4,932,893	5,633,182	-	-	-	-	-	-
Hurricane Purchase p393045	126,266	10,522	10,522	10,522	10,522	10,522	10,522	10,522	10,522	10,522	10,522	10,522	10,522
IPP Purchase	26,803,485	2,259,411	1,894,946	1,769,697	1,189,888	2,237,017	2,568,975	2,658,253	2,657,940	2,534,044	2,545,057	2,136,582	2,351,676
MagCorp p229846	-	-	-	-	-	-	-	-	-	-	-	-	-
MagCorp Reserves p510378	6,877,150	561,400	553,380	581,450	593,480	573,430	561,400	569,420	573,430	581,450	589,470	581,450	557,390
Nucor p346856	6,018,000	501,500	501,500	501,500	501,500	501,500	501,500	501,500	501,500	501,500	501,500	501,500	501,500
P4 Production p137215/p145258	19,999,999	1,666,667	1,666,667	1,666,667	1,666,667	1,666,667	1,666,667	1,666,667	1,666,667	1,666,667	1,666,667	1,666,667	1,666,667
PGE Cove p83984	154,785	12,899	12,899	12,899	12,899	12,899	12,899	12,899	12,899	12,899	12,899	12,899	12,899
Rock River Wind p100371	5,034,554	680,576	454,611	562,529	481,643	324,287	283,350	190,216	188,086	281,844	506,704	511,662	569,044
Small Purchases east	14,288	1,173	1,213	1,172	1,172	1,233	1,203	1,226	1,202	1,153	1,157	1,209	1,176
Small Purchases west	-	-	-	-	-	-	-	-	-	-	-	-	-
Three Buttes Wind p460457	21,900,784	2,950,042	2,048,922	2,268,067	1,790,156	1,522,263	1,376,527	915,605	1,110,451	1,208,578	1,763,698	2,344,477	2,602,000
Top of the World Wind p522807	43,163,842	5,675,352	4,007,657	4,588,167	3,723,277	3,180,993	2,809,599	1,990,205	2,035,002	2,244,343	3,532,172	4,592,308	4,784,770
Tri-State Purchase p27057	10,409,372	860,607	767,585	807,918	777,265	843,214	776,242	1,069,832	983,379	915,894	890,788	837,627	879,022
West Valley Toll	-	-	-	-	-	-	-	-	-	-	-	-	-
Wolverine Creek Wind p244520	10,581,890	769,966	927,019	1,223,945	1,077,890	870,483	924,641	707,826	699,677	690,703	828,162	982,254	879,322
Long Term Firm Purchases Total	238,041,898	26,717,582	23,386,862	25,007,545	22,533,324	20,581,800	21,507,938	14,661,679	14,697,433	14,707,381	16,877,771	18,330,388	19,032,195
Seasonal Purchased Power													
Constellation 2013-2016	5,089,376	-	-	-	-	-	-	1,746,800	1,854,576	1,488,000	-	-	-
Seasonal Purchased Power Total	5,089,376	-	-	-	-	-	-	1,746,800	1,854,576	1,488,000	-	-	-

PacifiCorp

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Net Power Cost Analysis

12 months ended December 2016	01/16-12/16	Jan-16	Feb-16	Mar-16	Apr-16	May-16	Jun-16	Jul-16	Aug-16	Sep-16	Oct-16	Nov-16	Dec-16
Qualifying Facilities													
QF California	7,126,982	655,677	754,337	820,422	1,045,929	1,061,305	822,623	388,861	290,451	268,239	269,515	300,789	448,834
QF Idaho	8,214,167	613,052	585,574	635,270	659,584	774,023	842,716	780,743	669,196	638,292	663,975	649,363	702,378
QF Oregon	27,220,939	2,213,267	2,130,527	2,412,202	2,766,562	2,870,663	2,576,498	2,190,260	2,071,817	2,120,337	1,897,302	1,674,821	2,296,684
QF Utah	9,102,693	585,580	616,681	720,017	744,707	811,720	873,429	857,572	893,007	835,407	801,128	713,438	650,008
QF Washington	276,208	-	-	-	11,064	25,247	44,325	58,990	63,048	51,646	21,890	-	-
QF Wyoming	214,412	22,234	21,945	24,923	17,973	14,891	12,066	14,669	15,427	14,157	14,216	20,346	21,566
Biomass One QF	15,291,428	1,384,512	1,338,960	1,387,295	1,206,407	837,781	825,564	1,441,275	1,469,283	1,432,225	1,456,705	1,217,783	1,293,636
Black Cap II Solar QF	-	-	-	-	-	-	-	-	-	-	-	-	-
Butter Creek Wind QF	-	-	-	-	-	-	-	-	-	-	-	-	-
Champlin Blue Mtn Wind QF	-	-	-	-	-	-	-	-	-	-	-	-	-
Chevron Wind p499335 QF	951,713	77,058	57,968	98,657	52,883	47,305	45,540	55,665	70,885	71,377	84,706	139,495	150,173
Chopin Wind QF	870,683	-	-	-	-	-	146,555	115,369	116,162	78,566	127,908	143,957	142,167
Co-Gen II	-	-	-	-	-	-	-	-	-	-	-	-	-
DCFP p316701 QF	154,620	10,588	7,370	10,282	13,265	17,113	16,730	15,578	13,724	11,614	19,449	13,034	5,873
Co-Gen II p349170 QF	-	-	-	-	-	-	-	-	-	-	-	-	-
Enterprise Solar I QF	1,113,187	-	-	-	-	-	-	-	-	-	27,465	595,928	489,795
Escalante Solar I QF	1,063,686	-	-	-	-	-	-	-	-	-	26,763	565,845	471,078
Escalante Solar II QF	1,017,582	-	-	-	-	-	-	-	-	-	25,574	541,277	450,732
Escalante Solar III QF	930,688	-	-	-	-	-	-	-	-	-	23,218	494,927	412,543
Evergreen BioPower p351030 QF	2,723,029	221,309	195,150	188,234	170,667	181,666	206,205	282,649	280,180	262,093	290,298	216,608	227,970
ExxonMobil p255042 QF	-	-	-	-	-	-	-	-	-	-	-	-	-
Five Pine Wind QF	7,640,280	599,313	713,852	683,662	647,143	506,349	463,950	558,000	649,010	598,347	648,793	758,578	813,282
Foote Creek III Wind QF	1,729,763	192,266	182,002	222,913	120,638	106,254	87,405	95,791	98,307	109,828	153,015	168,056	193,289
Granite Mountain East Solar QF	3,046,367	-	-	-	-	-	-	-	88,277	1,023,396	844,614	603,973	486,107
Granite Mountain West Solar QF	1,302,934	-	-	-	-	-	-	-	-	23,113	558,962	399,470	321,388
Iron Springs Solar QF	3,116,771	-	-	-	-	-	-	-	91,508	1,053,522	851,698	600,753	519,291
Kennecott Refinery QF	-	-	-	-	-	-	-	-	-	-	-	-	-
Kennecott Smelter QF	-	-	-	-	-	-	-	-	-	-	-	-	-
Latigo Wind Park QF	9,707,709	1,007,477	950,837	1,126,955	897,120	856,897	745,979	668,253	572,323	616,686	799,252	709,690	756,240
Long Ridge Wind I QF	-	-	-	-	-	-	-	-	-	-	-	-	-
Mariah Wind QF	-	-	-	-	-	-	-	-	-	-	-	-	-
Mountain Wind 1 p367721 QF	9,949,548	1,612,132	1,166,440	986,656	826,048	592,688	583,881	461,435	499,200	459,680	756,781	877,647	1,126,961
Mountain Wind 2 p398449 QF	15,336,994	2,324,070	1,716,181	1,505,837	1,234,690	911,192	1,035,503	849,897	822,420	765,825	1,104,885	1,397,691	1,668,805
North Point Wind QF	16,747,038	1,292,141	1,544,384	1,477,966	1,432,441	1,074,831	1,071,697	1,254,510	1,476,276	1,330,317	1,432,288	1,637,599	1,722,589
OM Power I Geothermal QF	-	-	-	-	-	-	-	-	-	-	-	-	-
Oregon Wind Farm QF	12,464,585	909,025	965,807	1,161,572	1,408,837	1,322,282	1,333,282	1,196,105	1,095,605	829,468	753,163	719,974	769,467
Orem Family Wind QF	-	-	-	-	-	-	-	-	-	-	-	-	-
Pavant II Solar QF	125,217	-	-	-	-	-	-	-	-	-	-	-	125,217
Pioneer Wind Park I QF	4,983,236	-	-	-	-	-	22,008	650,952	683,005	451,955	820,623	1,259,003	1,095,690
Power County North Wind QF p5756	4,674,158	381,157	466,179	440,071	444,493	317,036	307,270	312,183	308,299	321,132	418,650	415,580	542,108
Power County South Wind QF p5756	4,324,174	354,458	477,423	377,396	418,997	277,180	289,555	253,681	294,086	291,607	366,405	405,506	517,881
Roseburg Dillard QF	861,614	79,708	85,266	60,932	64,659	52,842	56,701	119,253	95,879	71,462	28,498	65,337	81,078
SF Phosphates	-	-	-	-	-	-	-	-	-	-	-	-	-
Spanish Fork Wind 2 p311681 QF	2,669,093	212,578	171,283	187,689	137,362	146,005	192,759	312,100	340,089	279,407	230,785	238,518	220,515
Sunnyside p83997/p59965 QF	28,752,568	2,518,536	2,440,635	2,507,593	1,715,887	2,540,943	2,459,285	2,526,996	2,464,774	2,444,680	2,132,025	2,450,145	2,551,069
Tata Chemicals QF	-	-	-	-	-	-	-	-	-	-	-	-	-
Tesoro QF	818,698	68,677	79,599	88,677	65,952	73,553	62,150	61,426	60,745	56,042	49,868	71,280	80,729
Threemile Canyon Wind QF p50013	1,743,670	100,301	143,911	147,786	197,456	194,882	214,833	177,367	165,071	108,524	99,562	98,312	95,665
US Magnesium QF	-	-	-	-	-	-	-	-	-	-	-	-	-
Utah Pavant Solar QF	4,205,934	156,620	209,161	340,630	372,298	408,203	467,079	567,085	543,247	428,669	331,137	213,551	168,254
Utah Red Hills Solar QF	6,085,152	270,417	319,249	411,433	547,440	606,881	651,714	777,283	749,701	537,018	451,752	286,009	476,254
Qualifying Facilities Total	216,557,519	17,862,153	17,340,720	18,025,067	17,220,503	16,629,732	16,457,302	17,043,948	17,051,000	17,584,630	18,582,864	20,664,283	22,095,317
Mid-Columbia Contracts													
Douglas - Wells p60828	3,640,469	303,372	303,372	303,372	303,372	303,372	303,372	303,372	303,372	303,372	303,372	303,372	303,372
Grant Reasonable	(2,253,794)	(187,816)	(187,816)	(187,816)	(187,816)	(187,816)	(187,816)	(187,816)	(187,816)	(187,816)	(187,816)	(187,816)	(187,816)
Grant Surplus p258951	2,039,032	169,919	169,919	169,919	169,919	169,919	169,919	169,919	169,919	169,919	169,919	169,919	169,919
Mid-Columbia Contracts Total	3,425,706	285,476	285,476	285,476	285,476	285,476	285,476	285,476	285,476	285,476	285,476	285,476	285,476
Total Long Term Firm Purchases	463,114,499	44,865,211	41,013,058	43,318,088	40,039,302	37,497,007	38,250,716	33,737,902	33,888,485	34,065,486	35,746,110	39,280,147	41,412,987

PacifiCorp

AugUpdate ORTAM16 NPC Study CONF

Net Power Cost Analysis

12 months ended December 2016	01/16-12/16	Jan-16	Feb-16	Mar-16	Apr-16	May-16	Jun-16	Jul-16	Aug-16	Sep-16	Oct-16	Nov-16	Dec-16
Storage & Exchange													
APS Exchange p58118/s58119	-	-	-	-	-	-	-	-	-	-	-	-	-
BPA FC II Wind p63507	-	-	-	-	-	-	-	-	-	-	-	-	-
BPA FC IV Wind p79207	-	-	-	-	-	-	-	-	-	-	-	-	-
BPA So. Idaho p64885/p83975/p647	-	-	-	-	-	-	-	-	-	-	-	-	-
Cowlitz Swift p65787	-	-	-	-	-	-	-	-	-	-	-	-	-
EWEB FC I p63508/p63510	-	-	-	-	-	-	-	-	-	-	-	-	-
PSCo Exchange p340325	5,400,000	450,000	450,000	450,000	450,000	450,000	450,000	450,000	450,000	450,000	450,000	450,000	450,000
PSCO FC III p63362/s63361	-	-	-	-	-	-	-	-	-	-	-	-	-
Redding Exchange p66276	-	-	-	-	-	-	-	-	-	-	-	-	-
SCL State Line p105228	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Storage & Exchange	5,400,000	450,000	450,000	450,000	450,000	450,000	450,000	450,000	450,000	450,000	450,000	450,000	450,000
Short Term Firm Purchases													
Mid Columbia	14,012,050	4,298,680	4,344,430	4,596,780	772,160	-	-	-	-	-	-	-	-
STF Electric Swaps	-	-	-	-	-	-	-	-	-	-	-	-	-
STF Index Trades	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Short Term Firm Purchases	14,012,050	4,298,680	4,344,430	4,596,780	772,160	-	-	-	-	-	-	-	-
System Balancing Purchases													
COB	15,933,838	125,135	242,954	2,285,450	2,723,517	2,011,470	2,186,969	1,112,908	2,581,238	1,555,980	327,708	163,401	617,107
Four Corners	3,259,890	38,548	493,933	502,063	400,702	29,768	563,939	170,065	342,198	190,609	388,321	106,723	33,021
Mead	6,567	-	5,642	-	521	-	-	-	-	404	-	-	-
Mid Columbia	28,808,592	107,023	56,097	734,574	535,795	2,494,907	2,175,845	11,605,105	5,439,143	188,017	2,465,992	1,206,703	1,799,391
Mona	5,221,367	373,779	403,974	1,350,346	373,675	386,335	230,293	399,942	350,785	155,997	321,556	403,044	471,641
NOB	1,580,964	54,308	138,512	26,838	106,409	49,221	242,184	236,163	137,029	88,219	-	38,800	463,280
Palo Verde	48,993	47,207	-	1,530	256	-	-	-	-	-	-	-	-
EIM Imports	(1,102,575)	(119,318)	(119,318)	(119,318)	(119,318)	(119,318)	(37,008)	(37,008)	(37,008)	(37,008)	(119,318)	(119,318)	(119,318)
Emergency Purchases	124,371	6,197	4	50,287	16,273	79	-	-	-	15,570	34,442	1,519	-
DA-RT Balancing	89,203,171	6,739,016	4,730,547	7,410,352	5,837,651	7,549,947	7,105,858	11,358,529	12,232,263	6,428,472	6,587,258	5,966,136	7,257,142
Total System Balancing Purchases	143,085,177	7,371,896	5,952,345	12,242,122	9,875,481	12,402,409	12,468,081	24,845,704	21,045,648	8,586,260	10,005,958	7,767,009	10,522,263
Total Purchased Power & Net Inte	625,611,726	56,985,787	51,759,833	60,606,990	51,136,943	50,349,416	51,168,797	59,033,606	55,384,134	43,101,746	46,202,069	47,497,155	52,385,250

PacifiCorp

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Net Power Cost Analysis

12 months ended December 2016	01/16-12/16	Jan-16	Feb-16	Mar-16	Apr-16	May-16	Jun-16	Jul-16	Aug-16	Sep-16	Oct-16	Nov-16	Dec-16
Wheeling & U. of F. Expense													
Firm Wheeling	148,076,415	12,681,970	13,155,489	13,551,947	12,743,042	11,820,862	11,979,724	12,051,073	11,468,983	11,895,301	12,086,927	11,984,247	12,656,851
C&T EIM Admin fee	496,878	43,852	38,141	38,808	37,128	38,510	40,548	45,455	46,342	43,128	41,212	40,758	42,996
ST Firm & Non-Firm	28,630	5,227	3,163	220	133	4,088	1,241	827	1,743	2,400	1,385	2,061	6,142
Total Wheeling & U. of F. Expense	148,601,924	12,731,049	13,196,793	13,590,975	12,780,302	11,863,459	12,021,513	12,097,355	11,517,068	11,940,830	12,129,524	12,027,065	12,705,989
Coal Fuel Burn Expense													
Carbon	-	-	-	-	-	-	-	-	-	-	-	-	-
Cholla	54,005,282	4,610,604	4,585,366	4,786,072	3,102,122	4,287,271	4,079,388	4,658,425	4,910,820	4,917,741	5,087,388	4,633,845	4,346,242
Colstrip	16,994,557	1,563,559	1,396,219	1,612,920	1,474,583	895,728	893,295	1,582,975	1,596,543	1,520,199	1,409,424	1,525,044	1,524,067
Craig	24,837,900	2,228,268	2,037,353	2,133,373	2,180,739	2,067,539	2,085,178	2,256,370	2,249,735	2,134,020	1,604,749	1,715,107	2,145,468
Dave Johnston	61,281,328	4,533,186	4,792,241	4,507,212	5,023,542	5,464,849	5,343,676	5,660,702	5,702,450	5,424,258	5,090,797	4,783,356	4,955,059
Hayden	12,275,672	1,200,113	1,020,241	1,069,243	408,210	661,072	943,939	1,143,811	1,242,450	1,099,249	1,210,013	1,161,245	1,116,085
Hunter	152,700,174	12,552,423	11,751,618	8,992,660	11,713,904	13,338,626	12,760,907	14,106,326	13,420,690	13,607,462	14,118,998	13,104,176	13,232,385
Huntington	117,866,410	11,208,137	9,274,939	11,062,490	9,435,438	8,344,539	9,584,579	10,546,640	11,127,337	8,616,173	7,732,798	9,664,437	11,268,902
Jim Bridger	234,139,317	20,124,807	19,144,062	19,332,942	14,864,421	13,821,914	16,938,716	21,975,624	22,886,584	21,150,037	21,868,414	20,234,671	21,797,124
Naughton	109,258,350	9,624,477	9,011,018	9,640,516	7,443,188	7,907,481	9,178,201	9,123,791	9,710,522	9,286,353	9,868,542	8,901,520	9,562,742
Wyodak	28,834,708	2,574,482	2,485,375	1,483,889	2,137,344	2,123,829	2,585,875	2,646,593	2,701,615	2,560,218	2,676,137	2,188,608	2,670,744
Total Coal Fuel Burn Expense	812,193,698	70,220,057	65,498,431	64,621,316	57,783,493	58,912,848	64,393,753	73,701,256	75,548,746	70,315,708	70,667,261	67,912,011	72,618,816
Gas Fuel Burn Expense													
Chehalis	53,492,501	3,538,108	3,289,590	4,038,879	3,931,825	5,113,788	3,975,570	6,447,932	5,418,914	6,143,009	6,682,776	2,097,365	2,814,744
Currant Creek	38,561,848	3,384,548	288,808	2,407,348	2,512,923	3,264,388	3,915,678	5,126,408	5,022,024	4,398,088	1,661,537	3,387,333	3,192,765
Gadsby	4,196,836	-	-	-	-	-	-	1,558,953	1,914,002	723,881	-	-	-
Gadsby CT	2,680,152	164,001	4,397	106,706	84,170	139,624	265,044	522,822	457,018	411,944	250,764	155,629	118,036
Hermiston	33,581,079	2,910,302	2,742,275	2,926,827	2,576,207	1,261,914	1,951,205	2,971,140	3,295,987	3,232,767	2,892,619	3,236,325	3,583,511
Lake Side 1	61,596,739	5,761,464	3,706,172	3,159,560	4,708,344	5,184,043	5,503,158	6,327,417	6,441,198	4,874,090	3,695,180	5,938,583	6,297,528
Lake Side 2	71,371,065	6,761,608	5,163,604	4,565,500	4,120,775	5,391,253	5,695,152	6,706,440	7,304,594	6,788,042	6,202,134	6,234,317	6,437,646
Little Mountain	-	-	-	-	-	-	-	-	-	-	-	-	-
Naughton - Gas	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Gas Fuel Burn	265,480,221	22,520,031	15,194,846	17,204,821	17,934,245	20,355,010	21,305,807	29,661,112	29,853,736	26,571,821	21,385,009	21,049,552	22,444,230
Gas Physical	(309,299)	(48,019)	(44,907)	(47,849)	(23,625)	(24,413)	(23,625)	(24,413)	(24,413)	(23,625)	(24,413)	-	-
Gas Swaps	27,079,035	2,177,363	2,176,088	2,697,233	2,419,500	2,578,038	2,428,500	2,142,720	2,184,570	2,224,200	2,170,000	2,080,500	1,800,325
Clay Basin Gas Storage	234,306	(48,880)	(45,082)	(20,074)	53,143	53,143	53,143	53,143	53,143	53,143	53,143	9,801	(33,460)
Pipeline Reservation Fees	37,844,410	3,173,528	3,076,766	3,173,528	3,125,147	3,173,528	3,125,147	3,192,596	3,192,596	3,145,391	3,192,596	3,113,191	3,160,397
Total Gas Fuel Burn Expense	330,328,673	27,774,023	20,357,712	23,007,658	23,508,410	26,135,306	26,888,972	35,025,159	35,259,633	31,970,930	26,776,336	26,253,045	27,371,492
Other Generation													
Blundell	4,836,760	452,194	379,347	454,977	378,118	303,423	394,235	389,209	405,130	385,733	422,759	436,708	434,927
Integration Charge	6,450,452	584,712	504,803	581,957	515,386	497,560	488,624	444,781	443,121	486,971	570,182	660,575	671,780
Total Other Generation	11,287,213	1,036,906	884,150	1,036,934	893,504	800,983	882,859	833,990	848,252	872,704	992,941	1,097,283	1,106,707
Net Power Cost	**1,536,650,137**	131,198,696	126,077,199	129,940,674	117,305,041	120,545,633	126,289,781	145,288,830	140,912,691	120,871,963	121,517,748	122,099,182	134,602,698
Net Power Cost/Net System Load	**25.19**	**24.38**	**25.68**	**26.34**	**25.14**	**25.14**	**25.45**	**25.59**	**25.45**	**24.82**	**24.95**	**24.59**	**24.79**

Docket No. UE 296
Exhibit PAC/503
Witness: Brian S. Dickman

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Reply Testimony of Brian S. Dickman

Correction and Update Summary

August 2015

Oregon TAM 2016 (April 2015 Initial Filing)		NPC ($) =	1,537,615,613
		$/MWh =	25.21

Corrections	**Impact ($)**	**NPC ($)**
C01 - Demand-Side Management (DSM) Cool Keeper Reserve	(99,929)	
C02 - Regulation Reserve Requirement	(472,820)	
C03 - Utah Red Hills Qualifying Facility (QF) Contract Price	176,211	
Total Corrections =	(396,538)	
Updates		
U01 - New QF Contracts	4,336,433	
U02 - Eagle Mountain Purchase	52,281	
U03 - QF Contract Status	(2,337,038)	
U04 - Pipeline Expenses	1,501,466	
U05 - Biomass One QF Non-Generation Agreement	18,590	
U06 - Official Forward Price Curve and Short Term Firm Transactions	141,571	
U07 - Douglas Public Utility District Pro-forma	(74,636)	
U08 - Black Hills Sale Fixed and Variable Charges	(328,951)	
U09 - PGE Cove Annual Cost	(80,257)	
U10 - Open Access Transmission Tariff Rates	908,919	
U11 - Goodnoe Hills Wheeling Interconnection Credit	(540,146)	
U12 - EIM Benefits	(2,903,665)	
U13 - Coal Cost	(1,838,325)	
Total Updates =	(1,143,759)	
System balancing impact of all adjustments	574,821	
Total Change from April 2015 Initial Filing	(965,476)	
Oregon TAM 2016 (August 2015 Filing)	**NPC ($) =**	**1,536,650,137**
	$/MWh =	**25.19**

Docket No. UE 296
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BEFORE THE PUBLIC UTILITY COMMISSION

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Exhibit Accompanying Reply Testimony of Brian S. Dickman

Other Revenue – Stand Alone TAM Adjustment

August 2015

PacifiCorp
CY 2016 TAM
Other Revenues - Stand Alone TAM Adjustment

		Total Company						**Oregon Allocated**		
Line no		UE-287 Final	CY 2016	Reply Update	Factor	Factors CY 2015	Factors CY 2016	UE-287 Final	CY 2016	Reply Update
1	Seattle City Light - Stateline Wind Farm	(9,932,463)	(9,811,103)	(9,811,103)	SG	25.687%	25.464%	(2,551,374)	(2,498,269)	(2,498,269)
2	Non-company owned Foote Creek	(1,106,372)	(900,697)	(904,400)	SG	25.687%	25.464%	(284,196)	(229,351)	(230,294)
3	BPA South Idaho Exchange	(9,240,627)	(4,691,490)	(4,691,490)	SG	25.687%	25.464%	(2,373,661)	(1,194,627)	(1,194,627)
4	Little Mountain Steam Revenues	-	-	-	SG	25.687%	25.464%	-	-	-
5	James River Royalty Offset	(3,926,947)	-	-	SG	25.687%	25.464%	(1,008,724)	-	-
6										
7	Total Other Revenue	(24,206,409)	(15,403,291)	(15,406,994)				(6,217,955)	(3,922,247)	(3,923,190)
8										
9					Decrease (Increase) in Other Revenues Absent Load Change				2,295,709	2,294,766
10										
11					Baseline Other Revenues in Rates			(6,217,955)		
12					$ Change due to load variance from UE 287 CY 2015 forecast			(13,988)		
13					Other Revenues in Rates using 2016 load forecast			(6,231,943)		
14										
15					**Decrease (Increase) in Other Revenues Including Load Change**				**2,309,696**	**2,308,753**

Docket No. UE 296
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BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Reply Testimony of Brian S. Dickman

EIM Costs

August 2015

PacifiCorp
Oregon 2016 TAM
EIM Costs

$ dollars

	CY 2016 EIM Costs 13 Month Average					
	Total Company		**Factor**	**Factors CY 2016**	**Oregon Allocated**	
	Initial Filing	**Reply Update**			**Initial Filing**	**Reply Update**
Capital Investment	16,291,370	16,291,370				
ADIT	(3,049,556)	(3,009,988)				
Depreciation Reserve	(3,810,701)	(3,812,898)				
Net Rate Base	9,431,113	9,468,484				
	10.75%	10.75%				
Pre-Tax Return on Rate Base	$ 1,014,212	$ 1,018,231	SG	25.464%	$ 258,256	$ 259,279
Operation & Maintenance (Ongoing)	1,259,600	1,258,805	SG	25.464%	320,741	320,538
Depreciation	2,338,567	2,339,433	SG	25.464%	595,486	595,706
Total Revenue Requirement	$ 4,612,380	$ 4,616,469			$ 1,174,482	$ 1,175,523
CAISO Fee in net power costs	$ 496,083	$ 496,878	SG	25.464%	126,321	126,523
Total EIM Costs	$ 5,108,463	$ 5,113,347			$ 1,300,803	$ 1,302,047

Docket No. UE 296
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BEFORE THE PUBLIC UTILITY COMMISSION

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PACIFICORP

Exhibit Accompanying Reply Testimony of Brian S. Dickman

EIM Benefits

August 2015

PacifiCorp
Oregon - CY 2016 TAM
EIM Benefits - PacifiCorp - CAISO Imports and Exports

PacifiCorp - CAISO EIM Import and Export Results

	12/1/2014	1/1/2015	2/1/2015	3/1/2015	4/1/2015	5/1/2015	6/1/2015	Total	Initial Filing OR TAM CY2016	Reply Update OR TAM CY2016
Export Volume (MWh)	98,946	71,737	46,617	51,641	51,937	89,956	119,969	530,803	956,682	913,590
Export Volume (aMW)	133	96	69	69	72	121	167	104	109	104
Import Volume (MWh)	15,611	11,520	19,124	12,630	15,178	13,548	6,815	94,426	162,788.97	144,074.33
Import Volume (aMW)	21	15	28	17	21	18	9	19	19	16
Transmission Left Open (MWh)	194,756	219,389	196,934	192,460	131,104	241,202	265,478	1,441,323	2,321,293	2,341,179
Transmission Left Open (aMW)	262	295	293	259	182	324	369	283	264	267
Export Margin	$527,961	$805,313	$337,132	$399,054	$533,708	$568,676	$1,196,382	$4,368,225	$7,473,033	$8,002,415
Import Margin	$151,027	$10,745	$200,979	$169,202	$145,151	$38,804	$37,008	$752,915	$970,632	$1,102,575
Export Load Factor	51%	33%	24%	27%	40%	37%	45%	37%	41%	39%
Export Margin $/MWh	$5.34	$11.23	$7.23	$7.73	$10.28	$6.32	$9.97	$8.23	$7.81	$8.76
Export $/MWh Avail Transmission	$2.71	$3.67	$1.71	$2.07	$4.07	$2.36	$4.51	$3.03	$3.22	$3.42
Import $/MWh	$9.67	$0.93	$10.51	$13.40	$9.56	$2.86	$5.43	$7.97	$5.96	$7.65
Total Benefit	**$678,987**	**$816,058**	**$538,111**	**$568,256**	**$678,859**	**$607,480**	**$1,233,390**	**$5,121,141**	**$8,443,665**	**$9,104,990**

Docket No. UE 296
Exhibit PAC/507
Witness: Brian S. Dickman

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Reply Testimony of Brian S. Dickman

Day-ahead and Real-time Transaction Cost Example

August 2015

	Market	Mid Columbia		
	Month	9		
	Hour Class	HLH		
		Average Price ($/MWh)		
	Period	Company Purchases	Market	Company Sales
1)	Sep-11	35.99	33.80	28.89
	Sep-12	26.92	25.71	23.23
	Sep-13	43.31	38.01	28.94
		Cost vs Market Average ($/MWh)		
2)	Sep-11	2.19		(4.91)
	Sep-12	1.22		(2.48)
	Sep-13	5.30		(9.07)
		Volume (MWh)		
	Sep-11	197,908		45,620
	Sep-12	115,128		47,972
	Sep-13	279,022		44,916
		Volume Weighted Three Year Average Cost vs Market		
3)	$	684,153		(250,125)
4)	$/MWh	3.47		(5.42)
		GRID Forecasted Cost, With Adders ($)		
	Sep-16	101,789		(96,166)
		Additional Forecasted Cost ($)		
5)	Sep-16	582,364		(153,959)
		Total Forecasted Cost ($)		
	Sep-16	684,153		(250,125)

Docket No. UE 296
Exhibit PAC/508
Witness: Brian S. Dickman

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Reply Testimony of Brian S. Dickman

ICNU Responses to PacifiCorp's Data Requests 3, 4, 8 and 13

August 2015

PACIFICORP DATA REQUEST NO. 3 TO ICNU:

Referring to Exhibit ICNU/100, Confidential Opening Testimony of Bradley G. Mullins (Mr. Mullins' testimony), page 2, line 11. Please define "bid-ask spread" as Mr. Mullins uses the term in his testimony, and provide support for Mr. Mullins' definition.

RESPONSE TO PACIFICORP DATA REQUEST NO. 3:

Mr. Mullins' definition of a bid-ask spread is modeling a purchase price in the GRID model that is higher than the sales price for the same market, as the Company has proposed to do in this proceeding through its system balancing adjustment. See Tinic, Seha M. and Richard R. West, Competition and the Pricing of Dealer Services in the Over-The-Counter Stock Market, Journal of Financial and Quantitative Analysis, Vol. 7 No. 3, at pages 1707 through 1727 (June 1972) for a discussion of the relationship of a bid-ask spread to market liquidity.

PACIFICORP DATA REQUEST NO. 4 TO ICNU:

Referring to Mr. Mullins' testimony, page 10, lines 5-8, Mr. Mullins states: "For purposes of power cost forecasting, it is generally accepted that there is no systematic bias between forward market prices and spot market prices. Accordingly, the market prices at which a utility will transact in forward markets to balance its systems represent the median expectation of what the ultimate spot market prices will be." Please provide the evidence or authorities upon which Mr. Mullins relied to develop and support these statements.

RESPONSE TO PACIFICORP DATA REQUEST NO. 4:

The fact that most utilities establish power cost forecasts based on forward price curves, without a downward adjustment to reflect a possible risk-premium, is evidence that these utilities generally accept the theory that there is no systematic bias between forward market prices and spot market prices. If the Company were to posit that there is a risk premium included in forward prices, then that would be a reason to reduce the forward prices for gas and electricity included in its forecast. It would also be evidence of systematic hedging costs, leading to the question of whether those costs should be borne by ratepayers or shareholders.

PACIFICORP DATA REQUEST NO. 8 TO ICNU:

Referring to Mr. Mullins' testimony, page 23, line 23 to page 24, lines 1-3:

a. Does Mr. Mullins agree that Control Performance Standard 2 measurement accounts for the number of periods during which area control error is within the L_{10} threshold?

b. Does Mr. Mullins agree that Control Performance Standard 2 measurement does not account for the magnitude of deviations in area control error beyond the L_{10} threshold?

RESPONSE TO PACIFICORP DATA REQUEST NO. 8:

a. Yes.
b. Yes.

PACIFICORP DATA REQUEST NO. 13 TO ICNU:

Referring to Mr. Mullins' testimony, beginning at page 39, line 11, regarding the imprudence of the Company's decision not to renew the Hermiston contract. Is it Mr. Mullins' position that the Commission should make a finding that non-renewal was imprudent, but also include the net power costs benefits of non-renewal in rates beginning in the 2016 TAM?

RESPONSE TO PACIFICORP DATA REQUEST NO. 13:

No.

Docket No. UE 296
Exhibit PAC/600
Witness: Frank C. Graves

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Reply Testimony of Frank C. Graves

August 2015

REPLY TESTIMONY OF FRANK C. GRAVES

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Q. Please state your name and position.

A. My name is Frank C. Graves. I am a Principal at the economic consulting firm *The Brattle Group*, where I am also the leader of the utility practice group. I am providing reply testimony in this case on behalf of PacifiCorp d/b/a Pacific Power (PacifiCorp or Company).

Q. Are you the same Frank Graves who provided Direct Testimony in this case?

A. Yes.

PURPOSE OF TESTIMONY

Q. What is the purpose of your reply testimony?

A. I have reviewed the Opening Testimony of Bradley G. Mullins on behalf of the Industrial Customers of Northwest Utilities (ICNU) and I respond to his position on the following topics:

(1) The relationship between spot and forward prices;

(2) What arbitrage is and is not;

(3) Mr. Mullins' belief that there are "no systematic costs to balancing;"

(4) What appears to be his misunderstanding of what PacifiCorp is asking for in this proceeding; and

(5) The notion that PacifiCorp is somehow "speculating."

For each of the topics listed above, I discuss how it relates to PacifiCorp's filing.

RESPONSE OF ICNU POSITIONS

Q. Can you clarify what is meant by balancing spot and forward transactions in PacifiCorp's system balancing proposal?

A. Yes. As is also explained in the Reply Testimony of Mr. Brian S. Dickman, the Company's proposal pertains to the costs of adjusting the prior supply commitments made for expected load and fuel needs to match (*i.e.*, balance) the actual realizations of load and plant usage that become apparent only a week or less in advance of delivery dates. These adjustments involve incremental "spot" trades (sales or purchases, as needed to balance) of short duration (*e.g.*, mostly day-ahead and real-time trades) at spot market prices rather than previously hedged prices. The costs reflect the differences between the realized spot prices for the Company's actual transaction volumes for hourly, daily and weekly products, and the historical average spot price for a given month.

Q. Please comment on Mr. Mullins' discussion of the relationship between spot and forward prices.[1]

A. Mr. Mullins offers several imprecise and/or incorrect characterizations of forward prices as median future spot prices. For example, he states that:

> … the market prices at which a utility will transact in forward markets to balance its systems represent the median expectation of what the ultimate spot market prices will be. The notion that forward prices are an unbiased estimate for future spot prices, however, does not mean that the future spot market price will ultimately be equal to what the forward market predicts.[2]

[1] I primarily comment on this issue to correct misconceptions. As noted below, the Company is *not* requesting any inclusion of a risk premium in its NPC.
[2] ICNU/100, Mullins/10.

I have two points of disagreement with this description. First, it is necessary for efficient forward prices to reflect the *expected* spot price not the median price, and these two will often be different because the distribution of possible spot prices tends to be skewed (with more room for upward movement than downward) such that the median, 50th percentile level is not necessarily the mean.

Second, it is not strictly true that the forward prices will or should equal the expected price. Forward buyers and sellers are trading off using a fixed forward price against simply waiting to transact at the risky spot price. To avoid arbitrage, these two have to be *equal in present value, not in delivery date value*. In general, it is likely that spot prices are somewhat systematically risky, because demand for most commodities tends to move with the economy as a whole. As a result, it is unlikely that the appropriate discount rate for taking the present value of expected spot prices will be the risk-free rate that applies to discounting the forward price. For the two present values to be equal, the two future values have to be somewhat different.

Q. Does this result in any typical pattern of relationship between the expected spot price and the prevailing futures price?

A. Yes, it appears that many commodities tend to be in "normal backwardation," whereby the futures price is below the expected spot price. It is difficult to be extremely precise empirically about this relationship, because the expected spot price cannot be directly observed. However, some studies have shown that buying futures contracts tends to result, over the long term, in positive profits comparable to the average return on the stock market as a whole. This can only happen if the buyer of the fixed forward position (the seller of the hedge to, *e.g.*, a producer that wants to avoid the spot risk) can then convert those positions to a short-term profit by selling at a higher prevailing spot price.[3] Equivalently, the future expected spot price has to be above the riskless forward price. As explained by Professors Gorton and Rouwenhorst,

> [A] producer of grain would sell grain futures to lock in the future price of his crops and obtain insurance against the price risk of grain at harvest time. Speculators would provide this insurance and buy futures, but demand a futures price which is below the spot price that could be expected to prevail at the maturity of the futures contract. By "backwardating" the futures price relative to the expected future spot price, speculators would receive a risk premium from producers for assuming the risk of future price fluctuations.[4]

Put differently, the party that provides access to the certain future price expects to earn a risk premium on that position for the insurance he or she is offering the counterparty and realizes this in the form of a payoff that consists of the desired risk premium, plus or minus any unexpected deviations of the future spot price from the expected spot price.

Q. Did Mr. Mullins provide any textbook or other support for his notion that "there is no systematic bias between forward market prices and spot market prices"?[5]

A. No. In his response to PacifiCorp data request No. 4, Mr. Mullins stated that he believes that:

> … most utilities establish power cost forecasts based on forward price curves, without a downward adjustment to reflect a possible risk-premium, is evidence that these utilities generally accept the theory that there is no systematic bias between forward market prices and spot market prices.[6]

[3] Gary Gorton & K. Geert Rouwenhorst, "Facts and Fantasies about Commodity Futures," *Financial Analysts Journal* 62, vol. 2 (Gorton & Rouwenhorst), p. 59.
[4] Gorton & Rouwenhorst, p. 48.
[5] ICNU/100, Mullins/9.
[6] *See* Exhibit PAC/508, ICNU Response to PacifiCorp Data Request No. 4.

In his response, Mr. Mullins did not cite specific utilities, empirical studies, or authoritative studies to substantiate his belief that using forwards is standard practice for forecasting. I agree that forwards are widely used as a reference point and often a starting point for utility forecasts, but rarely are they used for forecasting beyond about a few years ahead. Essentially all utilities I have worked with switch to fundamental modeling in a system simulation tool to predict the longer-term interactions of the supply and demand conditions they foresee.

I further note that when utilities rely on forwards for short-term forecasting or pricing, that does not necessarily mean or prove that they think those forwards are the best possible forecast. Rather, it may be that the forwards are simply a credible and non-controversial approximation to use, and that the utility is buffered from any errors that may ensue in how well the forwards match ultimate actual prices by having full recovery of such costs in their fuel adjustment clause, rather than having a sharing band. That is, in jurisdictions with no sharing band, the fact that realized power costs may deviate systematically from forecasted power costs merely causes a lag in recovery, whereas here for the Company, it tends to cause under recovery.

Q. How does the relationship between spot and forward prices relate to PacifiCorp's recovery of net power costs (NPC)?

A. Mr. Mullins believes that there should be no need for an NPC adjustment factor for balancing, in part because of his misperceptions of the forward prices as expected spot prices. He also confuses balancing costs with simple differences between forward and realized spot prices. Balancing occurs because system conditions change in many ways, not just because the realized spot price did not equal the prior forward price. Thus, it is important to understand that that the Company has *not* requested any risk premium associated with spot transactions, relative to forward prices.

Q. Please elaborate on how Mr. Mullins confuses balancing with simple closing of forward positions.

A. PacifiCorp has identified the cost of balancing its system by comparing the weighted average price when the Company transacted for purchase (or sales) volumes in the market to the average daily price for the month. These weighted average prices cannot be expected to, on average, be equal to the unweighted spot prices, which reflect identical volumes in every hour of a month. With the balancing occurring in the very near term, the spot price in any region is largely driven by regional factors rather than long-term fundamentals. Likewise, the volumes that will have to be balanced reflect shifting system conditions that themselves affect prices (while simple closing of forward positions at spot prices would not involve any change in volumes needed.) PacifiCorp is impacted by these same regional factors, and tends to purchase power when demand (and therefore price) is high, while the Company often sells power when demand (and hence price) is low. This effect was illustrated in Confidential Figure 3 of my Direct Testimony and is also shown in the Reply Testimony of Mr. Dickman.

Q. What has been the impact for PacifiCorp?

A. As shown in Mr. Dickman's Reply Testimony, the difference between the average market price and the spot price at which PacifiCorp has transacted has been substantial. For example, his data illustrates that for September 2013, the average market price was $38/MWh and the difference between the Company's purchase and the sale prices was about $14/MWh ($43/MWh minus $29/MWh).[7]

Q. What is the problem with the discussion of arbitrage in Mr. Mullins' testimony?

A. Mr. Mullins states that

> The principle that forward prices represent an unbiased estimate of future spot prices has its origin in arbitrage pricing theory. In an efficient market there are assumed to be no arbitrage opportunities—i.e., there is no opportunity for a market participant to earn a risk-free profit. To the extent that risk-free opportunities for profit were to exist in a forward market, the mechanics of supply and demand would result in an adjustment to prices to *eliminate the opportunity for a risk-free return*.[8]

First, he describes a condition that is far too strong and not necessary to prevent arbitrage, which does NOT prohibit earning a risk-free return; that happens every time one buys a Treasury bill. Instead, efficient markets prohibit persistently earning a return in excess of the fair risk-adjusted rate, net of the costs of organizing to pursue that return. The simplest example is expected returns on common stocks, which are increasing in the riskiness of the companies issuing those securities. A more concise version of the no-arbitrage principle is that one cannot consistently beat the market, if the marginal participants are equally well informed – but one can earn a nice, risk-adjusted return.

In this regard, there is strong and persistent evidence that forward traders do earn a systematic return, comparable to the return on common stocks generally, because of the above-mentioned normal backwardation. That is, realized spot prices for commodities tend to end up above their forward prices. The sellers of hedges

[7] PAC/500, Dickman/Confidential Figure 1.
[8] ICNU/100, Mullins/11 (emphasis added).

(buyers of the fixed position) essentially earn an insurance premium from the discount in their fixed forward prices.[9]

Q. What is your response to Mr. Mullins' statement that if "a utility is ultimately required to transact for more or less power in hourly spot markets than previously sold or purchased in forward markets, it is expected to be no better or worse off"?[10]

A. Mr. Mullins reaches this conclusion based on the faulty premises discussed above: (1) his confusion about the horizon over which the Company balances its power; (2) his misconception regarding the relationship between spot and forward prices; and (3) his incorrect belief that no-arbitrage means that one cannot earn a return. In addition, Mr. Mullins appears to ignore volume risk in actual operations and its correlated effects on prices. Forward gas and power prices can be locked in at *fixed* volumes, but actual forward demands for retail power (or for gas usage in electric dispatch) can only be estimated and cannot be locked down. Errors in forecasting, which are unavoidable given the volatility in demand, will generally impose additional costs to a utility. If there is any positive correlation between volume forecasting errors and price variability, then NPC will be higher than expected (*e.g.,* larger than expected purchase volumes tend to occur when prices are higher than expected and lower than expected purchase volumes tend to occur when prices are lower than expected). As illustrated in my Direct Testimony and in Mr. Dickman's Reply Testimony, the Company has experienced this phenomenon, which generally is likely to occur, because unexpected demand moves prices and vice versa.

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[9] *See* Gorton & Rouwenhorst, p. 48.
[10] ICNU/100, Mullins/10.

The costs associated with balancing load that is positively correlated with prices will not tend to balance out on the high and low side, because they involve a loss in either direction. Mr. Mullins' position that the utility would be no better or worse off would only apply if there were no correlation between demand and prices.

Q. Do you have a response to Mr. Mullins' citations to your prior testimony for evidence supporting the notion that the Company's hedging is unbiased and therefore there is no need for an adjustment?

A. Yes. Mr. Mullins makes statements such as:

> For purposes of the Company's system balancing proposal, the alleged system balancing costs in question are actually concerned with hedging contracts. It has generally been suggested by the Company that there are no systematic costs or biases associated with its hedging practice.[11]

These statements appear to rely on my observations in prior testimonies that utilities rely on forecasting to estimate their fuel and power procurement needs often using forward prices as part of that analysis (as discussed above) and that those forward prices have to be unbiased in the sense that neither the buyer or seller can expect to systematically gain a profit at the expense of the other party (*i.e.*, there cannot be an arbitrage opportunity that favors either side). I certainly agree that in this no-arbitrage sense (which is clarified above) that the forward prices should be unbiased.[12] However, there are two problems with Mr. Mullins' use of my prior testimony in the current context. First, my prior testimony pertained to PacifiCorp's use of longer-term hedges, whereas my testimony here pertains to short-term balancing transactions. These short-term balancing transactions would be necessary

[11] ICNU/100, Mullins/7-8.
[12] Supplemental Direct Testimony of Frank C. Graves, Utah Public Service Commission Docket No. 09-035-15.

and costly regardless of whether prior forward prices turned out to match realized all-hours average spot prices in the delivery periods. Second, as I noted in my testimony in Utah:

> Typically, these supplemental purchases will occur at higher prices than was originally forecast or locked in for the rest of the portfolio, because the new need is incremental and unexpected. And if the actual load is lower than forecasted, the utility will need to sell some excess energy to the market, possibly at a loss relative to the acquisition price.[13]

As in this case, I recognized that purchases in balancing transactions tend to occur at above-average prices, while sales tend to occur at below-average prices.

Q. What is your concern regarding Mr. Mullins' characterization of PacifiCorp's requested adjustment to the determination of the expected NPC?

A. Mr. Mullins' seems to believe that an "aspect of the Company's adjustment is to incorporate a bid-ask spread into the hourly market prices included in the GRID model."[14] Importantly, PacifiCorp is *not asking for a bid-ask spread* adjustment, which is the difference in price at any point in time between buying versus selling the same security immediately and concurrently. Instead, PacifiCorp is asking for the variances that tend to arise when they sell unplanned excess power into the spot market, or purchase supplemental power, for different volumes and under new expectations of market prices than prevailed previously. The sale of unplanned excess power and the procurement of needed supplemental power will not be concurrent transactions, so these transactions will not be subject to the same market conditions. Instead, these balancing sales of excess power occur when the Company is long in power while the procurements of additional power occur when the

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[13] *Id.* at 41.
[14] ICNU/100, Mullins/16.

Company is short. Because power spot prices fluctuate and often are correlated with regional supply and demand conditions, PacifiCorp may well find itself long on power, when relatively inexpensive power supply is also generally widely available relative to demand (hence prices are low, because this same unexpected outcome is affecting lots of participants in the market), while it may be short on power when power demand is broadly high and hence causing relatively expensive prices for supplemental supply.

Q. Should the purchases and sales considered in the Company's proposal be deemed to be, in part, based on speculation, as implied by Mr. Mullins?[15]

A. No, not at all. The term "speculation" applies only to market participants who are taking positions in opposition to the market's expectations, because they believe they have better information than other traders about what is likely to happen in the future. That is, speculation occurs when an entity takes on a calculated risk with the purpose of generating an arbitrage profit. In this case, PacifiCorp is strictly balancing its load and seeks a fair allowance for the expected costs of doing so.

Q. Does this complete your reply testimony?

A. Yes.

[15] ICNU/100, Mullins/8.

Docket No. UE 296
Exhibit PAC/700
Witness: Stephen A. Larsen

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

REDACTED
Reply Testimony of Stephen A. Larsen

August 2015

REPLY TESTIMONY OF STEPHEN A. LARSEN

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Q. Are you the same Stephen A. Larsen who previously submitted direct testimony in this proceeding on behalf of PacifiCorp d/b/a Pacific Power (PacifiCorp or the Company)?

A. Yes.

PURPOSE OF TESTIMONY

Q. What is the purpose of your reply testimony?

A. As part of the Company's 2016 Transition Adjustment Mechanism (TAM) reply update to net power costs (NPC), my testimony updates the level of coal costs included in fuel expense and explains the primary reasons for the variances compared to the initial filing in April 2015 (Initial Filing).

UPDATES TO COAL COSTS

Q. Please describe the Company's coal costs update.

A. Under the TAM Guidelines, the Company updates coal costs to reflect actual and projected changes in coal and transportation contracts that increase and decrease costs. The Company's filing also includes an update to a Bridger Coal Company contract related to the purchase of longwall equipment from the Deer Creek mine.

Q. What is the overall impact from this update?

A. Coal costs for the 2016 TAM have decreased $12.9 million on a total-Company basis, from $824.5 million in the Initial Filing to $811.6 million. This overall decrease results from changes in both the modeled coal volumes and prices. The Reply Update reduced coal volumes from 23.7 million tons in the Initial Filing to 23.5 million tons. The lower coal volume decreased NPC by $10.7 million. The updated coal prices reduced NPC by $2.2 million.

Q. What are the primary drivers of the $2.2 million decrease in coal prices?

A. Third-party coal purchases and transportation costs decreased [redacted], primarily as a result of updated price indices. This decrease was partially offset by a [redacted] increase in affiliate mining costs, primarily related to the contract cost increase at Bridger Coal Company for the purchase of the Deer Creek mine longwall equipment.

Q. Please identify the major components of the [redacted] decrease in third-party coal and transportation contract supplies.

A. The Company projects third-party coal and transportation supply cost decreases at the coal-fired plants as set forth in Confidential Table 1 below. The decrease is largely due to reductions in the Company's forecast diesel fuel forward price curve and contract-specific producer and consumer price indices, which are a result of updated price and inflation escalation assumptions. In addition, the coal price for the Dave Johnston plant reflects the lower prices resulting from the April 2015 Request for Proposals (RFP) solicitation for the plant. The coal price for the Hunter plant increased due to a contract price reopener.

Confidential Table 1: Coal and Transportation Contract Price Increases/(Decreases)

[redacted]

Q. Please describe the purchase of the longwall equipment from the Deer Creek mine by Bridger Coal Company.

A. Like the Deer Creek mine, the Bridger Coal Company underground mine uses longwall equipment to extract coal. When the Deer Creek mine was closed earlier this year, the longwall equipment was no longer needed at that mine. Given that the Deer Creek mine's longwall equipment was well-suited for the Bridger Coal Company underground mine, Energy West Mining Company, the PacifiCorp affiliate that operated the Deer Creek mine, entered into a contract with Bridger Coal Company to sell the Deer Creek mine longwall equipment to Bridger Coal Company.

Q. Has the Commission approved the sales contract transferring the longwall equipment?

A. Yes. On July 21, 2015, in Order No. 15-218, the Commission approved the sale after finding that the sales contract did not include any unusual or restrictive terms or conditions, that the pricing is fair and reasonable, and that the transaction is in the public interest.[1]

Q. Why did the longwall contract price differ from the amount included in the Company's Initial Filing?

A. In the Initial Filing, the assumed price for the longwall equipment contained estimated pricing. The updated filing reflects the actual contract price. The change in depreciation and operating expenses in 2016 associated with the updated longwall equipment price is [redacted].

Q. Is the Bridger Coal Company contract update consistent with the contract updates permitted under the TAM Guidelines?

A. Yes. The Company's update here is consistent with the TAM Guidelines' allowance of updates to third-party coal contracts.[2] My understanding is that the TAM Guidelines permit updates to contract costs because they are discrete costs that parties can easily verify by reference to the underlying contract. The Bridger Coal Company update here simply reflects the sales price included in the Commission-approved contract for the purchase of the longwall equipment. Not only can parties easily verify this cost by reference to the contract, the Commission has already approved the sale. Therefore, the update simply reflects updated contract costs allowed by the TAM Guidelines.

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[1] *Re PacifiCorp Application for an Order Authorizing the Transfer of Mining Equipment and Approval of an Affiliated Transaction with Bridger Coal Company*, Docket Nos. UP 328 & UI 357, Order No. 15-218, App. A at 7 (July 21, 2015).

[2] *See Re PacifiCorp 2009 Transition Adjustment Mechanism*, Docket No. UE 199, Order No. 09-274, App. A at 11 (July 16, 2009).

Q. Are there any other reasons to allow the update to Bridger Coal Company contract costs?

A. Yes. It is appropriate to include this update to the Bridger Coal Company operating cost in the TAM because the increased revenue from the sale of the longwall equipment flows back to customers through the mechanisms approved by the Commission in docket UM 1712,[3] as modified by the Commission's approval of the sale in Order No. 15-218.[4]

Q. Are there any other costs resulting from the Deer Creek mine closure reflected in the Company's NPC update?

A. Yes. Energy West Mining Company and Trapper mine costs remain unchanged. But there is a decrease in costs at the Huntington plant of [redacted] related to the transfer of previously mined Deer Creek coal from another stockpile to the Huntington plant. Together with the Bridger Coal Company longwall contract update, the total NPC change relating to the Deer Creek mine closure is an increase in NPC of [redacted].

Q. Does this conclude your reply testimony?

A. Yes.

[3] *Re PacifiCorp Application for Approval of Deer Creek Mine Transaction*, Docket No. UM 1712, Order No. 15-161 (May 27, 2015), *amended by* Order No. 15-166 (June 1, 2015).
[4] Order No. 15-218, App. A at 5-6.

Docket No. UE 296
Exhibit PAC/800
Witness: Judith M. Ridenour

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Reply Testimony of Judith M. Ridenour

August 2015

REPLY TESTIMONY OF JUDITH M. RIDENOUR

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Q. Are you the same Judith M. Ridenour who previously submitted direct testimony in this proceeding on behalf of PacifiCorp d/b/a Pacific Power (PacifiCorp or Company)?

A. Yes.

PURPOSE AND SUMMARY OF TESTIMONY

Q. What is the purpose of your testimony?

A. I respond to the testimony of Noble Americas Energy Solutions LLC (Noble Solutions) witness Kevin C. Higgins regarding the treatment of a late Direct Access Service Request (DASR) for customers requesting service under the Company's five-year opt-out direct access program under Schedule 296.

Q. Please summarize your testimony.

A. As approved in docket UE 267, the Company's five-year opt-out program requires service from the electric service supplier (ESS) to begin on January 1 to allow assessment of a full five years of transition adjustments, including the consumer opt-out charge, under the program. The Company must receive the DASR from the ESS 13 days before commencement of service from the ESS on January 1. Noble Solutions has offered no explanation why the amount of time now allowed for submission of the DASR is unworkable. There is no basis for modifying the Company's five-year opt-out program that was so recently approved in Order No. 15-060.[1]

[1] *Re PacifiCorp Transition Adjustment, Five-Year Cost of Service Opt-Out*, Docket No. UE 267, Order No. 15-060 (Feb. 24, 2015), *reconsideration denied*, Order No. 15-195 (June 16, 2015).

TREATMENT OF A LATE DIRECT ACCESS SERVICE REQUEST

Q. Please summarize Noble Solutions' concern on the treatment of a late DASR for a customer requesting service under the five-year opt-out program.

A. Noble Solutions is concerned that service under the five-year opt-out program must begin January 1, which requires that PacifiCorp receive the DASR 13 business days prior to January 1. This requirement is in PacifiCorp's direct access rules in its tariff.[2] Noble Solutions claims that this results in differential treatment under the five-year opt-out program compared to PacifiCorp's other direct access programs and that there is ambiguity as to how a customer will receive service if the ESS submits a late DASR.

Q. Please explain what information is included in a DASR.

A. A DASR contains standard industry information which is either readily available from the customer's monthly bill or known by the ESS. This includes the customer name, account number, billing address, point of delivery, and other relevant information necessary to effectuate the change in service. The information required in the DASR has not changed since direct access was first implemented many years ago.

Q. Do you agree that there is ambiguity as to how a five-year opt-out customer will be served if a DASR is received after the cut-off date for service beginning January 1?

A. No. From its initial filing, the language of Schedule 296 indicated that the five-year transition adjustments and customer opt-out charge apply to service beginning

[2] *See* Advice No. 11-002, Original Sheet No. R21-7 (effective Mar. 22, 2011).

January 1.[3] The treatment of late DASRs for the Company's five-year opt-out program was further clarified in the reply testimony of Joelle R. Steward in docket UE 267, beginning on page 11:

> **Q. Are there any other issues related to the election window that need to be addressed?**
> A. Yes. Service under Schedule 296 requires the customer to take supply service from an ESS. If the customer opts out, but the Company does not receive a DASR by the appropriate time to allow the ESS to provide service beginning on January 1, the Company proposes that the customer's opt-out election revert to the one-year program, Schedule 294. This means that the customer would be placed on Schedule 220, Standard Offer Supply Service, until a DASR is received. If a DASR is received, then the customer would be moved to Schedule 294, consistent with the tariff. The customer would have the ability to elect a Schedule 296 opt-out the following November, at which point the five-year transition would begin (assuming that the overall program cap has not been reached).[4]

Neither the language in the tariffs nor the description of the treatment of a late DASR were disputed in docket UE 267 by Noble Solutions or any other party. While Noble Solutions asserts that parties did not have an opportunity to respond to PacifiCorp's reply testimony, all parties had the opportunity to raise this issue in cross examination and in post-hearing briefs and chose not to do so.

Q. Why is the treatment of a late DASR under the Company's five-year opt-out program different than the treatment under the one- and three-year programs?

A. The Company's five-year opt-out program is different from the one- and three-year programs because customers pay transition adjustments for the five-year period but are then no longer subject to transition adjustments. This means that service under the five-year opt-out program commencing after January 1 would result in the customer paying less than the full five years of transition adjustments, including the

[3] Advice No. 13-004, Original Sheet No. 296-3 (Feb. 28, 2013).
[4] Docket No. UE 267, PAC/300, Steward/11-12 (Mar. 27, 2014).

customer opt-out charge. To avoid the full amount of transition adjustments, a customer could request or otherwise cause the submission of the DASR to be delayed.

To address this potential situation, the Company indicates in Schedule 296 that the transition adjustments are "Adjustments for Consumers Electing this Option for service beginning January 1, 2016."[5] Contrary to the statement in Mr. Higgins' testimony that the one- and three-year tariffs contain the same language, they do not.[6] Neither Schedule 294 nor 295 indicate that the transition adjustments apply only to service beginning on January 1 of the initial year.

Q. Are there also unique enrollment limitations on the five-year opt-out program?

A. Yes. The five-year opt-out program is limited to a total of 175 aMW. Requiring timely submission of a DASR is important to monitoring enrollment in the program.

Q. How much time does the ESS have to complete and submit the DASR to meet the deadline for January 1 service?

A. An ESS has four weeks from the first day of the open enrollment window to submit a DASR. There is also no constraint on the ability of the ESS to work with customers before the enrollment window opens. The ESS may submit a DASR at any time after the customer has submitted the Change of Service Election Declaration (CSED), which could be as early as the first day of the open enrollment period. Even after the close of the three-week open enrollment window,[7] the ESS has an additional week to submit the DASR to meet the deadline.

[5] Advice No. 15-004, Original Sheet No. 296-3 (effective Mar. 9, 2015).
[6] Noble Solutions/100, Higgins/29-30.
[7] In his testimony Mr. Higgins incorrectly cites that the end of the 2015 multi-year opt-out open enrollment window as Monday, December 4, 2015 which is not a valid date. The correct date is Monday, December 7, 2015.

Q. Does Noble Solutions provide a reason why it cannot meet the DASR submission deadline?

A. No. Noble Solutions offers no explanation why it cannot meet the DASR deadline. It is the ESS's responsibility to submit the DASR in time for the customer to commence service at the beginning of the election period.

Q. Has Noble Solutions offered any new evidence or arguments for changing the provisions adopted in docket UE 267 for the five-year opt-out program, including the requirement that the DASR must be received 13 days prior to the commencement of service on January 1?

A. No. As noted in the reply testimony of Brian S. Dickman, when denying Noble Solutions' petition for reconsideration in docket UE 267, the Commission stated that if parties wanted to challenge the Company's five-year opt-out program in the future, they must present new evidence or arguments.[8] Noble Solutions has not met this requirement here.

Q. If the Commission decided to allow direct access customers to commence service under the five-year opt-out program on a date after January 1, is Noble Solutions' proposal for the customer to pay the difference between what they paid under Schedule 220 from January 1 to the commencement of service on the program and the costs under the program reasonable?

A. Generally speaking, yes. While this proposal adds administrative complexities, if the Commission decides to allow five-year opt-out program customers to commence service after January 1, then those customers should pay the difference between the

[8] *Re PacifiCorp's Transition Adjustment, Five-Year Cost of Service Opt-Out*, Docket UE 267, Order No. 15-195 at 2-3 (June 16, 2015).

transition adjustments they paid under Schedule 220/294 and the transition adjustments plus the consumer opt-out charge under Schedule 296.

If the Commission allows customers to join the five-year opt-out program after January 1, the Company recommends that service from the ESS should commence no later than February 1. This will avoid the adjustment becoming unreasonably large and will keep program administration from becoming overly complicated. The completed DASR would still need to be submitted 13 days prior to the ESS service commencement date.

Q. Does this conclude your reply testimony?

A. Yes.