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June 9, 2017

Via Electronic Filing

Public Utility Commission of Oregon
Attn: Filing Center
201 High St. SE, Suite 100
Salem OR 97301

Re: In the Matter of PACIFICORP's 2018 Transition Adjustment Mechanism
Docket No. UE 323

Dear Filing Center:

Please find enclosed the redacted version of the Opening Testimony and Exhibits of Bradley G. Mullins on behalf of the Industrial Customers of Northwest Utilities ("ICNU") in the above-referenced docket.

The confidential portions of ICNU's testimony are being handled pursuant to Order No. 16-128 and will follow to the Commission via Federal Express.

Thank you for your assistance. If you have any questions, please do not hesitate to call.

Sincerely,

/s/ Jesse O. Gorsuch
Jesse O. Gorsuch

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that I have this day served the confidential portions of the **Opening Testimony of the Industrial Customers of Northwest Utilities** upon the parties shown below by mailing a copy via First Class U.S. Mail, postage prepaid.

Dated at Portland, Oregon, this 9th day of June, 2017

Sincerely,

/s/ Jesse O. Gorsuch
Jesse O. Gorsuch

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BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 323

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In the Matter of	)
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PACIFICORP, dba PACIFIC POWER,	)
	)
2018 Transition Adjustment Mechanism.	)
	)
	)

OPENING TESTIMONY OF BRADLEY G. MULLINS

ON BEHALF OF THE INDUSTRIAL CUSTOMERS OF NORTHWEST UTILITIES

(REDACTED VERSION)

June 9, 2017

EXHIBIT LIST

ICNU/101 – Regulatory Appearances of Bradley G. Mullins

ICNU/102 – Company Response to OPUC Data Request 002

ICNU/103 – Actual Net Power Cost Report for 2016

Confidential ICNU/104 – Analysis of >7 Day Transactions in DA/RT Adjustment

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Bradley G. Mullins, and my business address is 333 SW Taylor Street, Suite 400, Portland, Oregon 97204.

Q. PLEASE STATE YOUR OCCUPATION AND IDENTIFY THE PARTY ON WHOSE BEHALF YOU ARE TESTIFYING.

A. I am an independent consultant representing energy and utility customers in jurisdictions around the United States and am appearing in this matter—the 2018 Transition Adjustment Mechanism ("TAM") filing of Pacific Power (the "Company")—on behalf of the Industrial Customers of Northwest Utilities ("ICNU"). ICNU is a non-profit trade association whose members are large customers of electric utilities located throughout the Pacific Northwest, including customers of the Company.

Q. PLEASE SUMMARIZE YOUR EDUCATION AND WORK EXPERIENCE.

A. I have a Master of Science degree in Accounting from the University of Utah. After obtaining my Master's degree I worked at Deloitte, where I ultimately specialized in research and development tax credits. Subsequently, I worked at PacifiCorp as an analyst involved in regulatory matters surrounding power supply costs. I currently provide services to utility customers on matters such as power costs, revenue requirement, rate spread and rate design. I have sponsored testimony in numerous regulatory jurisdictions throughout the United States, including before the Oregon Public Utility Commission ("Commission"). A list of my regulatory appearances can be found in Exhibit No. ICNU/101.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. I respond to the Direct Testimony of Mr. Michael G. Wilding filed on behalf of the Company in this matter, regarding the Company's proposed net power costs ("NPC") forecast for 2018 developed using the Generation and Regulation Initiative Decision Tools ("GRID") model.

Q. WHAT LEVEL OF NPC HAS THE COMPANY PROPOSED IN THIS MATTER?

A. The Company proposes to update the level of NPC reflected in rates to be $1,545.6 million on a total-Company basis,[1/] and $380.4 million on an Oregon-allocated basis.[2/] Relative to the Company's actual NPC in 2016, this represents an increase of approximately $79.7 million on a total-Company basis.

Q. WHAT WAS THE NATURE OF YOUR REVIEW OF THE COMPANY'S FILING?

A. I have reviewed the inputs of the Company into the GRID model, and have performed analysis surrounding various aspects of the Company's filing, such as the Day-Ahead and Real-Time System Balancing ("DA/RT") adjustment addressed in Order No. 16-482 in the 2017 TAM.[3/] I have also issued several data requests and reviewed the Company's responses to those requests. In addition, I participated in five workshops prior to the 2018 TAM filing that the Company conducted as a result of the requirement in Order No. 16-482.

Q. WHAT ARE YOUR INITIAL RECOMMENDATIONS IN THIS MATTER?

A. Based on my review, I have developed the following two recommendations.

First, I recommend the Company perform a backcast to demonstrate that the GRID model—inclusive of the various exogenous adjustments that have been implemented over the

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1/ PAC/102 at 5.
2/ PAC/100 at 3:7-8.
3/ Docket No. UE 307.

years—produces a reliable forecast.

Second, I continue to have concerns with the DA/RT adjustment, particularly in the absence of a backcast to validate the need for such an adjustment. Based on the analysis discussed below—which provides a more holistic review of the impact of the DA/RT adjustment methodology—the impact of the DA/RT adjustment is appropriately reduced by $24.1 million on a total-Company basis.

II. NEED FOR A BACKCAST

Q. SHOULD THE COMPANY PERFORM A BACKCAST?

A. Yes. In contrast to a forecast based on expected inputs for a future period, a backcast represents a model run populated with historical input data with the objective of duplicating results that actually occurred. The purpose of a backcast is to gauge the accuracy of a model following the premise that, for it to be considered accurate, a model populated with actual, historical inputs must produce overall results that are comparable to actual results. Such an analysis is routinely conducted when performing analytical modeling, and the Company is probably overdue in conducting one with respect to the GRID model.

The need for a backcast with respect to the GRID model is made more pressing due to the many exogenous adjustments—e.g., the DA/RT adjustment, day-ahead wind integration costs, intra-hour wind integration reserves, market caps, thermal plant screening, energy imbalance market ("EIM") benefits, etc.—made to GRID model results. Many of these adjustments have been discussed and litigated before the Commission in past proceedings. Some increase NPC and others reduce NPC. Consideration of these adjustments, however, has largely been done in isolation, rather than considering whether all of the adjustments, collectively, produce reasonable results. A backcast, on the other hand, would provide an opportunity to consider the collective impacts of all of the modeling adjustments that have been implemented in the past, and thus, may provide information that the Commission finds to be a useful starting point in evaluating the totality of the NPC forecast the Company develops in its annual TAM filings.

Q. HAS THE COMPANY PERFORMED A BACKCAST IN THE PAST?

A. Yes. My understanding is that the Company performed multiple backcasts around the time that the GRID model was developed.[4/] In 2003, for example, the Company prepared a backcast that Randy Falkenberg reviewed on behalf of ICNU.[5/] Mr. Falkenberg noted, "[i]n the analysis, the Company contended that GRID predicted power costs within 0.1% of actual."[6/] Since then, there have been many adjustments made with respect to the GRID modeling, and there have also been many changes in the electric services industry. The GRID model developers, for example, clearly did not contemplate the Company's participation in a regional, sub-hourly, EIM. Given the amount of time that has transpired and changes that have occurred since the last backcast, it is not unreasonable for the Company to perform a new backcast to reevaluate its modeling on a holistic basis.

Q. DID STAFF REQUEST THE COMPANY PERFORM A BACKCAST IN THIS MATTER?

A. Yes. In its Data Request 002, Staff requested the Company perform a backcast, based on a specific set of input parameters.[7/]

4/ The GRID model was originally developed in, or around, 2001.

5/ See Re Pacific Power Light Request for a General Rate Increase in the Company's Oregon Annual Revenues, Docket No. UE 170, Surrebuttal Testimony of Randall J. Falkenberg, ICNU/111 at 24:13-24.

6/ Id.

7/ ICNU/102 at 1 (the Company's response to Staff Data Request 002).

Q. DID THE COMPANY PERFORM THE ANALYSIS?

A. No.[8/]

Q. DO YOU AGREE WITH THE ALL OF THE PARAMETERS PROPOSED BY STAFF?

A. While I agree with many of the parameters, I would probably perform a backcast in a slightly different way. Initially, I would attempt to conform the analysis as closely as possible to the overall methodology that is used to set rates, including all of the exogenous adjustments. Thus, the "Market Cap" constraint is probably better modeled in a backcast based on the same four-year methodology that the Company currently uses, rather than using the methodology described in subpart (b) of the Staff request. Similarly, I would initially model market prices in a backcast based on the same DA/RT and scalar methodology, albeit based on actual monthly market prices rather than monthly forward prices used in the forecast. Using hourly POWERDEX prices, as Staff suggests, however, could subsequently be used as a sensitivity to test whether changes are warranted in the Company's hourly price scaling methodology.

Q. IS PERFORMING A BACKCAST BURDENSOME?

A. It is true that performing a backcast in the GRID model is not an insignificant undertaking. Doing so requires manual analysis of large quantities of hourly data inputs, which can be time-consuming when working with the GRID model. Although, it can also fairly be said that performing a single modeling run in the GRID model is burdensome. It can take about a day of intensive data analysis just to conduct the plant screening processes for a single model run. Thermal plant screening is a process developed to overcome a deficiency in the GRID model

8/ Id.

commitment logic by manually calculating the hourly commitment of gas plants outside of the GRID model.[9/]

Q. DO YOU HAVE ANY SUGGESTIONS REGARDING HOW TO PERFORM THE ANALYSIS IN A LESS BURDENSOME MANNER?

A. Limiting the analysis to calendar year 2016 should serve to reduce the level of burden associated with a backcast. Under this approach, the Company could use the final NPC studies approved in the 2016 TAM as a starting point, and populate those model runs with actual price, load and resource data from 2016.

Q. HOW DID THE NPC FORECAST IN THE 2016 TAM COMPARE TO ACTUAL NPC IN 2016?

A. The modeling in the 2016 TAM is based on normalized input assumptions. In actual operations, however, the Company experienced different loads, different levels of revenues, different market prices, different levels of output from hydro and wind resources, and other factors that are not reflected in a normalized power cost study. Thus, absent a full backcast, it is somewhat difficult to isolate whether the forecast error in the 2016 TAM was the result of non-normal conditions or faulty modeling. Notwithstanding, some pertinent information can be ascertained from such an analysis.

The final GRID model run in the 2016 TAM forecast NPC of $1,521.1 million on a total-Company basis. In comparison, the Company incurred Actual NPC of $1,465.9 million on a total-Company basis in 2016. Thus, the Company over-forecast total NPC by approximately $55.2 million in 2016. A copy of the actual NPC report of the Company for

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[9/] See Re PacifiCorp, dba Pacific Power, 2009 Transition Adjustment Mechanism Schedule 200, Cost-Based Supply Service, Docket UE 199, Direct Testimony of Randy Falkenberg, Exhibit ICNU/100 at 15:18-28:21; See also Docket UE 199, Rebuttal Testimony of Gregory N. Duvall, Exhibit PPL/106 at 1:18-2:4 (stating the Company's agreement to Mr. Falkenberg's adjustment).

2016 was provided in response to ICNU Data Request 11 and is attached as Exhibit No. ICNU/103.

Q. HAVE YOU ISOLATED SOME OF THE CAUSES OF THE COMPANY'S OVER-FORECASTING IN THE 2016 TAM?

A. Yes. Table 1, below, presents a conventional analysis known as a "side-by-side" analysis. It presents the various components of NPC from the respective filings and compares them on the basis of total dollars and volumes, with the objective of determining which NPC categories are driving the forecast variance.

CONFIDENTIAL TABLE 1
NPC Side-by-Side
2016 TAM v. 2016 Actual

	2016 TAM			2016 Actual NPC			Delta					
	$M	GWh	$/MWh	$M	GWh	$/MWh	$M	%	GWh	%	$/MWh	%
L.T. Sales for Resale	[redacted]	[redacted]	[redacted]	(27.7)	(612)	45.26	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
S.T. Sales for Resale	[redacted]	[redacted]	[redacted]	(148.1)	(6,019)	24.60	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
L.T. Purch. and Exch.	[redacted]	[redacted]	[redacted]	205.2	2,828	72.56	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Qualif. Facilities	[redacted]	[redacted]	[redacted]	204.2	3,513	58.14	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Mid-C Contracts	[redacted]	[redacted]	[redacted]	4.2	340	12.45	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
S.T. Purchases	[redacted]	[redacted]	[redacted]	83.0	4,706	17.63	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Coal Gen.	[redacted]	[redacted]	[redacted]	751.7	36,583	20.55	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Gas Gen.	[redacted]	[redacted]	[redacted]	257.0	9,887	26.00	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Hydro Gen.		[redacted]			3,843				[redacted]	[redacted]		
Renewable Gen.	[redacted]	[redacted]		3.9	3,256		[redacted]		[redacted]	[redacted]		
Wheeling	[redacted]			132.4			[redacted]	[redacted]				
Total NPC / Net Re	**1,521.1**	**60,875**	**24.99**	**1,465.9**	**58,327**	**25.13**	**(55.2)**	**-4%**	**(2,548)**	**-4%**	**(0.15)**	**-1%**

As can be seen from the table, there are many differences between the level of NPC included in the 2016 TAM and actual NPC in 2016. Loads were about 2,548 GWh less than forecast, and were a key driver to the lower-than-expected NPC.

Another notable item in the table above appears on the line "S.T. Purchases." In the 2016 TAM, the Company forecast an average rate for short-term purchases of approximately

$[redacted]/MWh, inclusive of the impacts of the DA/RT adjustment. In actual operations, however, the Company made short-term purchases at an average rate of $17.63/MWh. Thus, the 2017 TAM forecast of the Company and average cost of short-term market purchases varies by approximately $[redacted]/MWh or [redacted]%. This variance runs counter to the underpinnings of the DA/RT adjustment, which is designed to capture "the price difference between the average market price and the company's actual prices for balancing transactions."[10/]

Q. HOW DOES ACTUAL NPC IN 2016 COMPARE TO NPC REQUESTED IN THIS MATTER?

A. In this matter, the Company has forecast NPC of $1,545.6 million. Thus, the Company's filing represents an increase of $79.7 million relative to the $1,465.9 million actually incurred in 2016. Oregon loads are expected to remain flat relative to 2016 levels and the cost of power continues to decline. Accordingly, the driver of the material increase in NPC is not entirely clear based on the information the Company has presented in this matter.

Q. PLEASE SUMMARIZE YOUR RECOMMENDATION.

A. A backcast using 2016 data would provide useful information in helping the Commission understand the overall accuracy of the Company's GRID modeling, and for that reason, I believe that the Company would be justified in performing such an analysis.

10/ Docket No. UE 307, Order 16-482 at 14.

III. DA/RT SYSTEM BALANCING ADJUSTMENT

Q. IS THE DA/RT ADJUSTMENT APPROPRIATELY INCLUDED IN THE COMPANY'S FORECAST?

A. I continue to disagree with the merits of the DA/RT adjustment and have performed some additional analysis indicating that the impact of the adjustment is likely overstated. While it may be true that the subset of transactions the Company identified have historically settled unfavorably relative to monthly market prices, there are other components of NPC, which may settle favorably relative to monthly market prices, producing offsetting benefits relative to the Company's approach. I have analyzed the impact of broadening the scope of transactions subject to the DA/RT adjustment, and based on my review, recommend reducing the impact of the DA/RT adjustment by $24.1 million on a total-Company basis.

Q. DID YOU IDENTIFY ANY ERRORS THE DA/RT ADJUSTMENT THE COMPANY CALCULATED?

A. Yes. The workpaper titled "ORTAM18w_DA-RT Price Adder (1612) (CY2016-2020) CONF," contains an error on tab "Adders," rows "184:189." The formula the Company used on these rows incorrectly referenced the market prices from the month prior to that intended. The impact of correcting this error is an approximate $0.6 million reduction to the impact of the DA/RT adjustment on a total-Company basis.

Q. DO YOU AGREE THAT THE DA/RT ADJUSTMENT IS APPROPRIATELY CHARACTERIZED AS HAVING TWO COMPONENTS?

A. No. The Company characterizes the DA/RT adjustment as having two components: 1) a price component; and 2) a volume component. I, however, disagree that it is appropriate to characterize the adjustment in such a manner. Based on the way that the adjustment is calculated, the complicated mechanics underlying the price and volume components are irrelevant. As a final step in the Company's implementation of the DA/RT adjustment, the Company applies a plug, outside of the GRID model, to force the total impact of the DA/RT adjustment to tie to the historical average, which in this case the Company has proposed as the 60 months ending in June 2016. Accordingly, it is more appropriate to view the Company's adjustment as a single adjustment based solely on the historical averages, rather than viewing it as two, largely arbitrary, components.

Q. WHY DID THE COMPANY OVER-FORECAST THE AVERAGE $/MWH COST OF SHORT-TERM PURCHASES IN THE 2016 TAM, AS DETAILED IN CONFIDENTIAL TABLE 1 ABOVE?

A. I think one contributing factor may have to do with the fact that the Company limited its calculation of the DA/RT adjustment to include only those historical transactions executed less than seven days prior to the period when power is settled. The Company does not, however, balance its system solely with transactions made less than seven days prior to the settlement period. The Company also balances its system by "layering-in" longer-term transactions over an extended period of time, which contribute to the average cost of purchases in the test period. In the DA/RT adjustment, the Company adds an additional systematic cost for transactions of less than seven days, yet does not consider whether the longer-term transactions are systematically settling favorably, or unfavorably, relative to the market. That is, there may be offsetting systematic benefits associated with the layering-in of longer-term transactions which are being ignored due to the way that the Company limits its analysis to transactions executed less than seven days prior to settlement. For simplicity purposes through the remainder of this testimony, I refer to these two classes of transactions as "<7 Day Transactions" and ">7 Day Transactions."

Q. HAVE YOU CONDUCTED ANALYSIS OF THE SYSTEMATIC IMPACT OF >7 DAY TRANSACTIONS IN THE DA/RT ADJUSTMENT?

A. Yes. I reviewed the impact of the Company's assumption restricting the adjustment calculation to <7 Day Transactions. I used the workpapers the Company provided in response to Staff Data Requests 5 and 6, which contain the hourly transaction data used to inform the DA/RT adjustment and are where the Company applied the filter to limit the transactions to those executed less than seven days prior to settlement. With respect to these workpapers, the only change made was removing the filtering criteria that limited the analysis to <7 Day Transactions. That is, my analysis includes all transactions, irrespective of whether the transaction was done within seven days of the settlement period. Based on these modified workpapers, I performed updated DA/RT adjustment calculations. The difference between the updated DA/RT adjustment calculation and the original DA/RT adjustment calculation was then appropriately attributed to the >7 Day Transactions.

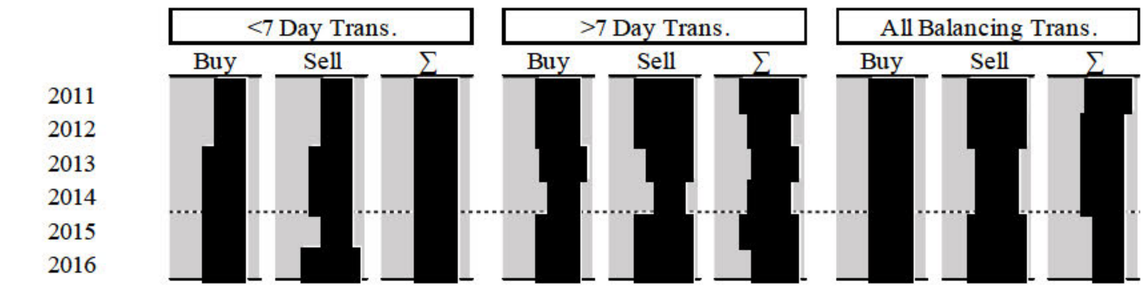
Q. WHAT WAS THE RESULT OF YOUR ANALYSIS?

A. Confidential Table 2, below, presents a comparison of the DA/RT adjustment calculated with, and without, transactions executed more than seven days prior to settlement. In Confidential Exhibit No. ICNU/103, I have broken the table out further into transactions made in the PACE and PACW balancing areas, which provides some interesting insights into ways the Company uses combinations of short-term, day-ahead, and real-time transactions to balance its system.

CONFIDENTIAL TABLE 2

Impact of >7 Day Transactions on DA/RT Adjustment

Cost/(benefit) over monthly market prices, $millions



Average Annual:	<7 Day Buy	<7 Day Sell	<7 Day ∑	>7 Day Buy	>7 Day Sell	>7 Day ∑	All Balancing Buy	All Balancing Sell	All Balancing ∑
2011-2016	19.3	4.9	24.3	19.4	(23.2)	(3.8)	38.7	(18.3)	20.4
7/2011 - 6/2016	18.9	8.8	**27.7** (a)	16.9	(18.3)	(1.4)	35.8	(9.6)	26.3
2015-2016	25.2	(3.7)	21.5	26.9	(44.3)	(17.4)	52.2	(48.0)	**4.1** (b)

(a) Company Proposed DA/RT adjustment with error correction

(b) ICNU proposed DA/RT adjustment

Q. WHAT HAVE YOU CONCLUDED BASED ON YOUR ANALYSIS OF THIS DATA?

A. First, the annual impact of the DA/RT adjustment has been very volatile on a year-to-year basis. Including only <7 day transactions, the impact was as high as $[redacted] million in 2014, compared to just $[redacted] million in 2016. The volatility in the impact of the DA/RT adjustment is further exacerbated if transactions >7 days are included in the analysis. If all balancing transactions are included, the impact was $[redacted] million in 2014, compared to only $[redacted] million in 2016. In fact, if all balancing transactions are included, the DA/RT adjustment actually produced a benefit of $[redacted] million in 2011. As a result of this volatility, one would appropriately conclude that the costs at issue with respect to the DA/RT adjustment are difficult, if not impossible, to forecast accurately.

Second, the data demonstrate a discrete shift beginning in 2015, which is demarked by the dashed line in the table. This is when the Company began participating in the EIM. As can be noted, the overall DA/RT cost with all balancing transactions declined from $[redacted] million to $[redacted] million in 2016. This shift appears to be driven predominantly by the impacts of the >7 day transactions, which settled favorably relative to the monthly market in an amount of $[redacted] million and $[redacted] million in 2015 and 2016, respectively.

Q. BASED ON THIS ANALYSIS, WHAT DO YOU RECOMMEND?

A. Based on my analysis, I recommend that the DA/RT adjustment be calculated only over the period 2015 to 2016. This period encompasses only the time since the Company began participating in the EIM. This change is appropriate since the Company has clearly made some changes to the way that it balances its system since it began participating in the EIM. Second, I recommend that the impact of the >7 day transactions be included in the calculation. Since 2015, this class of transactions has settled favorably relative to monthly market prices, and is appropriately considered as a component of the Company's system balancing activities.

Q. WHAT IS THE IMPACT OF YOUR RECOMMENDATION?

A. The Company has proposed to include a total DA/RT adjustment of approximately $28.2 million on a total-Company basis. This amount is appropriately reduced by $0.6 million to $27.7 million to address the formula error identified above. Further, modifying the calculation to include the >7 Day Transactions and limiting the calculation to 2015 and 2016, produces a DA/RT adjustment of $4.1 million. Thus, the total impact of my recommendation, including the impact of the error identified above, is a reduction to NPC of approximately $24.1 million on a total-Company basis.

Q. DOES THIS CONCLUDE YOUR OPENING POWER COST TESTIMONY?

A. Yes.

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 323

In the Matter of	)
	)
PACIFICORP, dba PACIFIC POWER,	)
	)
2018 Transition Adjustment Mechanism.	)
	)

EXHIBIT NO. ICNU/101

REGULATORY APPEARANCES OF BRADLEY G. MULLINS

Q. PLEASE PROVIDE A LIST OF YOUR REGULATORY APPEARANCES.

A. I have sponsored testimony in the following regulatory proceedings:

- Or.PUC, UE 323: In re Portland General Electric Company, Request for a General Rate Revision
- Or.PUC, UM 1811: In re Portland General Electric Company, Application for Transportation Electrification Programs
- Or.PUC, UM 1810: In re Pacific Power & Light Company, Application for Transportation Electrification Programs
- Wa.UTC, UE-161204: In re Pacific Power & Light Company, Revisions to Tariff WN-U-75 (Net Removal Tariff)
- Wa.UTC, UE-161123: In re Puget Sound Energy's Revisions to Tariff WN U-60, Adding Schedule 451, Implementing a New Retail Wheeling Service
- Bonneville Power Administration, BP-18: 2018 Joint Power and Transmission Rate Proceeding
- Or.PUC, UP 334 (Cons.): In re Portland General Electric Company Application for Approval of Sale of Harborton Restoration Project Property
- Ar.PSC, 16-028-U: In re An Investigation of Policies Related to Renewable Distributed Electric Generation
- Ar.PSC, 16-027-R: In re Net Metering and the Implementation of Act 827 of 2015
- Ut.PSC, 16-035-01: In re the Application of Rocky Mountain Power for Approval of the 2016 Energy Balancing Account

- Wa.UTC, UE-160228, UG-160229: In re Avista Corporation Request for a General Rate Revision
- Wy.PSC, 20000-292-EA-16: In re the Application of Rocky Mountain Power to Decrease Current Rates by $2.7 Million to Recover Deferred Net Power Costs Pursuant to Tariff Schedule 95 and to Increase Rates by $50 Thousand Pursuant to Tariff Schedule 93
- Or.PUC, UE 307: In re PacifiCorp, dba Pacific Power, 2017 Transition Adjustment Mechanism
- Or.PUC, UE 308: In re Portland General Electric Company, 2017 Annual Power Cost Update Tariff (Schedule 125)
- Or.PUC, UM 1050: In re PacifiCorp, Request to Initiate an Investigation of Multi-Jurisdictional Issues and Approve an Inter-Jurisdictional Cost Allocation Protocol
- Wa.UTC, UE-152253: In re Pacific Power & Light Company, General rate increase for electric services
- Wy.PSC, 20000-469-ER-15 In The Matter of the Application of Rocky Mountain Power for Authority of a General Rate Increase in Its Retail Electric Utility Service Rates in Wyoming of $32.4 Million Per Year or 4.5 Percent
- Wa.UTC, UE-150204: In re Avista Corporation, General Rate Increase for Electric Services
- Wy.PSC, 20000-472-EA-15: In re the Application of Rocky Mountain Power to Decrease Rates by $17.6 Million to Recover Deferred Net Power Costs Pursuant to Tariff Schedule 95 to Decrease Rates by $4.7 Million Pursuant to Tariff Schedule 93

- Wa.UTC, UE-143932: Formal complaint of The Walla Walla Country Club against Pacific Power & Light Company for refusal to provide disconnection under Commission-approved terms and fees, as mandated under Company tariff rules
- Or.PUC, UE 296: In re PacifiCorp, dba Pacific Power, 2016 Transition Adjustment Mechanism
- Or.PUC, UE 294: In re Portland General Electric Company, Request for a General Rate Revision
- Or.PUC, UM 1662: In re Portland General Electric Company and PacifiCorp dba Pacific Power, Request for Generic Power Cost Adjustment Mechanism Investigation
- Or.PUC, UM 1712: In re PacifiCorp, dba Pacific Power, Application for Approval of Deer Creek Mine Transaction
- Or.PUC, UM 1719: In re Public Utility Commission of Oregon, Investigation to Explore Issues Related to a Renewable Generator's Contribution to Capacity
- Or.PUC, UM 1623: In re Portland General Electric Company, Application for Deferral Accounting of Excess Pension Costs and Carrying Costs on Cash Contributions
- Bonneville Power Administration, BP-16: 2016 Joint Power and Transmission Rate Proceeding
- Wa.UTC, UE-141368: In re Puget Sound Energy, Petition to Update Methodologies Used to Allocate Electric Cost of Service and for Electric Rate Design Purposes
- Wa.UTC, UE-140762: In re Pacific Power & Light Company, Request for a General Rate Revision Resulting in an Overall Price Change of 8.5 Percent, or $27.2 Million

- Wa.UTC, UE-141141: In re Puget Sound Energy, Revises the Power Cost Rate in WN U-60, Tariff G, Schedule 95, to reflect a decrease of $9,554,847 in the Company's overall normalized power supply costs
- Wy.PSC, 20000-446-ER-14: In re the Application of Rocky Mountain Power for Authority to Increase Its Retail Electric Utility Service Rates in Wyoming Approximately $36.1 Million Per Year or 5.3 Percent
- Wa.UTC, UE-140188: In re Avista Corporation, General Rate Increase for Electric Services, RE: Tariff WN U-28, Which Proposes an Overall Net Electric Billed Increase of 5.5 Percent Effective January 1, 2015
- Or.PUC, UM 1689: In re PacifiCorp, dba Pacific Power, Application for Deferred Accounting and Prudence Determination Associated with the Energy Imbalance Market
- Or.PUC, UE 287: In re PacifiCorp, dba Pacific Power, 2015 Transition Adjustment Mechanism.
- Or.PUC, UE 283: In re Portland General Electric Company, Request for a General Rate Revision
- Or.PUC, UE 286: In re Portland General Electric Company's Net Variable Power Costs (NVPC) and Annual Power Cost Update (APCU)
- Or.PUC, UE 281: In re Portland General Electric Company 2014 Schedule 145 Boardman Power Plant Operating Adjustment
- Or.PUC, UE 267: In re PacifiCorp, dba Pacific Power, Transition Adjustment, Five-Year Cost of Service Opt-Out (adopting testimony of Donald W. Schoenbeck).

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 323

In the Matter of	)
	)
PACIFICORP, dba PACIFIC POWER,	)
	)
2018 Transition Adjustment Mechanism.	)
	)

EXHIBIT NO. ICNU/102

COMPANY RESPONSE TO OPUC DATA REQUEST 002

UE 323 / PacifiCorp
May 26, 2017
OPUC Data Request 2

OPUC Data Request 2

Please provide backcast GRID model results and model inputs for 2012, 2013, 2014, 2015, and 2016. In addition to providing the results, please provide parties access to the GRID runs via the online portal. Please use the GRID inputs used in the final approved GRIG forecast for each year with the following exceptions:

(a) Replace market energy prices with actual hourly POWERDEX prices for each hub;

(b) Replace market sale capacity to equal the maximum aggregate hourly transaction size within the year at each hub;

(c) Replace fuel costs with generating unit specific actual fuel costs or fuel cost curves at the most granular time period available to the Company;

(d) Replace load with actual load;

(e) Replace planned outages with actual planned and forced outages;

(f) Eliminate forced outage rate constraints;

(g) Replace heat rate to equal actual heat rate or actual heat rate curve; and

(h) Replace hydro conditions with actual hydro conditions.

Response to OPUC Data Request 2

The Company objects to this request on the basis that it is overly broad and unduly burdensome, and not reasonably calculated to lead to the discovery of admissible evidence. Notwithstanding the foregoing objection, the Company responds as follows:

The Company has not performed any backcast studies for the period of 2012 through 2016 using the Generation and Regulation Initiative Decision Tool (GRID). Please refer to the Company's response to OPUC Data Request 3.

(a) Please refer to the Company's response to Sierra Club Data Request 1.4; specifically Confidential Attachment Sierra Club 1.4, which includes actual hourly market prices for 2012 through 2016. Note: Confidential Attachment Sierra Club 1.4 contains confidential and proprietary third party data which is the property of POWERDEX. The POWERDEX actual hourly market prices are provided subject to the PacifiCorp POWERDEX Subscription Agreement which requires that POWERDEX proprietary data be provided only to persons qualified to receive confidential information under the protective order for this proceeding. Furthermore, parties must return or destroy all POWERDEX data that the Company provides in responses to data requests in this proceeding, and any extracts thereof, following conclusion of this regulatory proceeding.

(b) Please refer to the Company's response to OPUC Data Request 5; specifically Confidential Attachment OPUC 5, and the Company's response to OPUC Data Request 6; specifically Confidential Attachment OPUC 6, which provide short-term firm (STF) market transactions from 2009 through 2016. In addition, please refer to the confidential work paper entitled "ORTAM18_Market Capacity FEB17 CONF", tab entitled "48 month Source" which was included with the five-day work papers supporting the Company's 2018 transition adjustment mechanism (TAM). This work paper provides STF sales transaction for July 2012 through June 2016.

(c) Please refer to the Company's response to ICNU Data Request 011; specifically Attachment ICNU 011 -1, which provides actual net power costs (NPC) reports for 2012 through 2016. Actual fuel costs can be derived by taking the dollars divided by megawatt-hours (MWh) for each unit by month.

(d) Please refer to Confidential Attachment OPUC 2 –1, which provides actual hourly load for 2012 through 2016.

(e) Please refer to Confidential Attachment OPUC 2 –2, which provides actual planned and forced outage data for the Company's owned thermal, hydroelectric and wind generation facilities in the period of 2012 through 2016.

(f) Please refer to the Company's response to subpart (e) above.

(g) Please refer to the confidential work paper entitled "ORTAM18w_HeatRateCurves 16Jun CONF.zip", which was included with the five-day work papers supporting the Company's 2018 TAM.

(h) Please refer to Confidential Attachment OPUC 2 –3, which provides actual hourly owned hydroelectric generation for 2012 through 2016.

Confidential information is designated as Protected Information under Order No. 16-128 and may only be disclosed to qualified persons as defined in that order.

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 323

In the Matter of	)
	)
PACIFICORP, dba PACIFIC POWER,	)
	)
2018 Transition Adjustment Mechanism.	)
	)

EXHIBIT NO. ICNU/103

ACTUAL NET POWER COST REPORT FOR 2016

PACIFICORP
ACTUAL NET POWER COST REPORT
FOR THE YEAR ENDING DECEMBER 31, 2016

	Total	Jan-16	Feb-16	Mar-16	Apr-16	May-16	Jun-16	Jul-16	Aug-16	Sep-16	Oct-16	Nov-16	Dec-16
								DOLLARS					
SPECIAL SALES FOR RESALE													
Long Term Firm Sales													
Black Hills	$ 12,563,485	$ 957,311	$ 955,107	$ 941,596	$ 940,677	$ 1,015,150	$ 991,673	$ 1,134,689	$ 1,236,510	$ 1,161,869	$ 1,089,986	$ 978,783	$ 1,160,134
BPA Wind	3,203,785	332,007	405,770	291,848	207,556	494,256	118,594	173,184	115,038	177,159	287,316	256,500	344,556
Hurricane Sale	15,990	1,235	1,235	1,235	1,170	1,300	1,365	1,495	1,495	1,365	1,430	1,300	1,365
LADWP (IPP Layoff)	3,318,535	2,310,335	574,056	434,144	-	-	-	-	-	-	-	-	-
SMUD	(135,779)	-	-	-	-	(135,779)	-	-	-	-	-	-	-
UMPA II	8,731,659	472,103	413,650	418,521	419,896	422,091	932,984	1,780,719	1,400,832	793,036	593,573	490,680	593,573
Total Long Term Firm Sales	27,697,675	4,072,991	2,349,818	2,087,343	1,569,300	1,797,019	2,044,616	3,090,087	2,753,876	2,133,429	1,972,305	1,727,262	2,099,628
Short Term Firm Sales													
Short Term Firm Sales	145,438,583	$ 16,332,340	$ 14,259,053	$ 6,514,752	$ 5,773,245	$ 7,065,879	$ 5,930,760	$ 11,037,627	$ 9,353,673	$ 14,020,796	$ 18,478,283	$ 16,835,625	$ 19,836,549
Other Firm Sales	2,646,158	229,203	4,719	164,425	43,819	48,022	389,388	386,302	244,771	198,438	307,613	158,151	471,306
Total Short Term Firm Sales	148,084,741	$ 16,561,544	$ 14,263,772	$ 6,679,177	$ 5,817,064	$ 7,113,901	$ 6,320,148	$ 11,423,929	$ 9,598,445	$ 14,219,234	$ 18,785,897	$ 16,993,776	$ 20,307,856
Total Secondary Sales	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Special Sales For Resale	**$ 175,782,416**	**$ 20,634,535**	**$ 16,613,590**	**$ 8,766,520**	**$ 7,386,364**	**$ 8,910,920**	**$ 8,364,764**	**$ 14,514,016**	**$ 12,352,320**	**$ 16,352,662**	**$ 20,758,202**	**$ 18,721,038**	**$ 22,407,484**

ICNU/103
Mullins/2

PACIFICORP
ACTUAL NET POWER COST REPORT
FOR THE YEAR ENDING DECEMBER 31, 2016

	Total	Jan-16	Feb-16	Mar-16	Apr-16	May-16	Jun-16	Jul-16	Aug-16	Sep-16	Oct-16	Nov-16	Dec-16
PURCHASED POWER & NET INTERCHANGE													
Long Term Firm Purchases													
APS Supplemental	$ 717,362	$ 8,787	$ -	$ 73,961	$ 27,599	$ 21,456	$ 16,529	$ 21,662	$ 59,693	$ 97,032	$ 132,701	$ 101,985	$ 155,960
Combine Hills Wind	5,541,593	347,483	484,546	589,657	472,655	505,664	449,303	437,633	368,136	405,360	462,668	510,356	508,129
Deseret Purchase	27,099,336	2,329,856	1,985,340	2,221,939	2,268,101	1,758,375	2,310,845	2,342,716	2,537,938	2,288,949	2,242,382	2,279,978	2,532,918
Douglas PUD Settlement	2,144,642	15,052	105,119	260,115	298,607	341,480	255,100	173,619	124,558	86,670	199,834	219,650	64,838
Eagle Mountain - UAMPS/UMPA	2,627,238	170,786	148,314	249,367	133,805	237,601	267,371	294,460	257,580	244,525	207,677	172,411	243,341
Gemstate	1,182,925	106,300	102,900	105,100	102,900	102,900	102,900	102,900	115,500	102,900	137,228	137,228	(35,831)
Hermiston Purchase	28,622,215	5,523,382	5,212,556	4,822,149	4,251,243	4,054,764	4,651,741	180,554	-	-	(74,173)	-	-
Hurricane Purchase	126,653	14,859	14,450	10,706	8,658	7,313	6,669	11,934	14,625	12,870	8,600	7,137	8,834
IPP Purchase	3,318,535	2,310,335	574,056	434,144	-	-	-	-	-	-	-	-	-
MagCorp Reserves	6,706,025	575,226	531,298	581,838	561,877	580,299	558,836	568,456	572,266	542,523	543,642	546,169	543,595
Nucor	7,129,800	594,150	594,150	594,150	594,150	594,150	594,150	594,150	594,150	594,150	594,150	594,150	594,150
Old Mill Solar	659,436	-	-	3,371	56,789	60,952	113,913	127,039	113,300	88,673	43,831	31,592	19,976
Pavant III Solar	5,072	-	-	-	-	-	-	-	-	-	-	-	5,072
P4 Production	20,293,365	1,960,345	1,666,980	1,666,980	1,456,735	1,666,980	1,666,980	1,666,980	1,666,980	1,666,980	1,666,980	1,438,295	2,102,150
PGE Cove	134,406	11,000	16,000	16,000	16,000	16,000	16,000	(36,594)	16,000	16,000	16,000	16,000	16,000
Rock River Wind	5,172,608	634,124	565,523	497,722	405,963	310,106	212,514	297,587	205,140	333,928	541,180	457,835	710,986
Small Purchases east	41,271	3,389	4,921	3,862	3,323	3,076	3,130	3,297	3,513	3,113	3,074	3,066	3,507
Small Purchases west	-	-	-	-	-	-	-	-	-	-	-	-	-
Three Buttes Wind	21,250,160	2,655,793	2,573,883	2,232,525	1,429,522	1,249,661	1,065,517	1,059,061	1,164,862	1,455,694	2,050,299	1,853,961	2,459,381
Top of the World Wind	42,967,632	4,690,976	5,216,328	4,495,224	2,918,841	2,723,259	2,051,174	2,200,106	2,502,764	3,153,958	4,199,862	4,004,475	4,810,665
Tri-State Purchase	8,994,013	728,818	699,849	740,463	723,868	716,920	764,705	775,176	777,111	789,359	772,447	760,834	744,461
Wolverine Creek Wind	10,243,985	778,462	934,499	1,023,699	834,235	720,278	748,976	801,862	596,207	717,237	1,133,837	847,851	1,106,843
Subtotal Long Term Firm Purchase	$ 194,978,269	$ 23,459,122	$ 21,430,711	$ 20,622,970	$ 16,564,870	$ 15,671,233	$ 15,856,353	$ 11,622,598	$ 11,690,323	$ 12,599,923	$ 14,882,217	$ 13,982,972	$ 16,594,976
Seasonal Purchased Power													
Constellation 2013-2016	$ 4,830,993	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,818,943	$ 1,770,462	$ 1,238,480	$ 3,108	$ -	$ -
Total Seasonal Purchased Power	$ 4,830,993	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,818,943	$ 1,770,462	$ 1,238,480	$ 3,108	$ -	$ -

PACIFICORP
ACTUAL NET POWER COST REPORT
FOR THE YEAR ENDING DECEMBER 31, 2016

	Total	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	$ 7,979,979	$ 711,058	$ 1,002,185	$ 1,111,824	$ 1,070,400	$ 704,258	$ 370,728	$ 285,159	$ 389,632	$ 341,270	$ 416,241	$ 772,108	$ 805,115
QF Idaho	8,078,869	531,403	536,765	634,565	608,474	889,054	888,288	755,225	653,064	580,500	666,250	712,857	622,424
QF Oregon	24,455,986	1,957,523	2,060,644	2,761,300	2,656,145	2,260,025	1,958,793	1,856,798	1,832,038	1,696,489	1,789,262	1,732,083	1,894,888
QF Utah	7,275,178	492,656	571,860	630,872	618,564	677,014	680,889	628,603	601,554	659,334	618,572	559,171	536,088
QF Washington	301,945	6,521	6,083	5,350	19,719	50,440	58,518	60,636	57,230	31,859	5,589	-	-
QF Wyoming	281,635	35,211	36,768	35,137	24,539	18,766	12,660	24,356	19,455	15,638	20,675	17,697	20,732
Biomass One QF	14,257,282	1,344,832	1,361,635	1,396,119	1,373,827	865,864	854,754	875,125	1,387,865	1,474,954	1,388,906	1,410,194	523,207
Chevron Wind QF	576,848	53,268	77,732	87,204	41,899	38,729	31,264	35,397	34,581	34,758	44,425	38,835	58,756
Chopin Wind QF	471,389	-	-	-	-	-	-	-	-	-	146,416	157,654	167,319
DCFP QF	100,096	438	3,911	5,050	6,683	6,754	12,693	11,634	6,001	15,815	14,804	8,324	7,990
Enterprise Solar I QF	4,497,225	-	-	-	-	97,161	571,285	937,233	704,237	511,500	408,448	718,695	548,665
Escalante 1 Solar QF	2,961,710	-	-	-	-	-	-	500,576	610,726	486,377	379,989	591,532	392,511
Escalante 2 Solar QF	3,195,581	-	-	-	-	-	-	761,538	663,180	482,781	363,187	553,812	371,083
Escalante 3 Solar QF	3,187,028	-	-	-	-	-	-	860,370	650,635	473,647	375,752	497,532	329,092
Evergreen BioPower QF	3,460,539	193,070	170,894	229,915	313,067	315,201	350,202	365,011	384,905	345,514	287,479	257,406	247,877
ExxonMobil QF	11,023	-	-	-	-	-	-	11,023	-	-	-	-	-
Five Pine Wind QF	6,013,899	500,166	679,618	689,670	596,204	390,074	480,160	671,636	423,236	-	-	559,683	1,023,453
Foote Creek III Wind QF	1,631,017	177,961	239,076	211,385	102,785	80,708	53,616	116,625	78,354	94,592	163,250	125,184	187,482
Granite Mountain East Solar QF	2,344,172	-	-	-	-	-	-	-	424,537	253,654	642,410	598,886	424,685
Granite Mountain West Solar QF	1,095,004	-	-	-	-	-	-	-	93,902	153,080	174,856	385,985	287,182
Iron Springs QF	4,775,689	-	-	-	-	-	566,989	637,508	713,203	1,009,815	769,582	625,471	453,120
Kennecott Refinery QF	-	-	-	-	-	-	-	-	-	-	-	-	-
Kennecott Smelter QF	-	-	-	-	-	-	-	-	-	-	-	-	-
Latigo Wind QF	6,336,211	-	87,680	529,043	620,877	518,329	623,232	599,739	545,831	729,431	588,682	841,596	651,770
Mountain Wind 1 QF	9,021,283	1,082,405	1,360,652	835,049	531,330	475,074	386,588	798,956	457,050	654,921	654,705	517,243	1,267,310
Mountain Wind 2 QF	13,773,713	1,549,179	1,937,649	1,293,095	787,059	673,048	693,614	1,417,168	813,523	1,044,477	1,005,704	728,820	1,830,378
North Point Wind QF	13,303,597	1,057,570	1,383,912	1,624,876	1,337,561	866,270	1,072,934	1,616,806	1,024,093	-	-	1,287,841	2,031,733
Oregon Wind Farm QF	11,184,984	546,005	821,601	1,134,345	1,122,599	1,272,012	1,040,095	1,140,872	969,000	1,015,133	841,724	493,946	787,653
Pavant II Solar QF	176,112	-	-	-	-	-	-	-	-	-	5,141	91,217	79,754
Pioneer Wind 1 QF	2,949,562	-	-	-	-	-	-	-	-	26	543,251	1,235,804	1,170,482
Power County North Wind QF	4,544,696	307,368	387,745	444,811	332,670	229,514	252,206	386,152	337,758	332,319	451,233	349,896	733,023
Power County South Wind QF	3,878,177	222,951	367,653	398,390	296,345	197,165	208,214	289,863	275,871	265,520	422,170	295,792	638,243
Roseburg Dillard QF	705,545	48,294	44,104	47,936	77,063	79,287	37,033	78,249	64,422	36,447	78,490	64,238	49,983
SF Phosphates QF	-	-	-	-	-	-	-	-	-	-	-	-	-
Spanish Fork Wind 2 QF	2,937,916	487,400	162,172	164,994	148,704	157,121	214,452	279,128	319,939	222,050	229,826	277,214	274,917
Sunnyside QF	27,501,790	2,552,886	2,438,780	2,491,671	859,282	2,277,211	2,523,557	2,515,938	2,566,875	2,199,745	2,314,325	2,475,419	2,286,100
Tesoro QF	476,569	43,633	36,068	56,242	42,363	84,240	11,226	8,349	13,448	30,737	49,078	45,221	55,963
Three Peaks Solar QF	235,041	-	-	-	-	-	-	-	-	-	-	-	235,041
Threemile Canyon Wind QF	1,547,751	64,088	92,737	147,667	178,990	201,182	179,349	163,705	119,511	120,146	88,840	93,030	98,505
US Magnesium QF	-	-	-	-	-	-	-	-	-	-	-	-	-
Utah Pavant Solar QF	3,707,324	135,636	193,680	244,549	299,777	375,843	440,743	553,526	456,838	394,174	272,513	227,187	112,858
Utah Red Hills Solar QF	5,007,102	187,256	241,930	263,645	303,128	381,882	686,107	943,477	698,903	496,669	386,909	209,861	207,334
Subtotal Qualifying Facilities	$ 204,239,464	$ 14,288,778	$ 16,303,533	$ 17,474,704	$ 14,370,055	$ 14,182,225	$ 15,260,188	$ 20,186,383	$ 18,391,395	$ 16,203,373	$ 16,608,680	$ 19,557,435	$ 21,412,714
Mid-Columbia Contracts													
Douglas - Wells	$ 3,650,764	$ 301,236	$ 301,236	$ 301,236	$ 301,236	$ 301,236	$ 301,236	$ 301,236	$ 301,236	$ 310,219	$ 310,219	$ 310,219	$ 310,219
Grant Surplus	2,003,126	166,927	166,927	166,927	166,927	166,927	166,927	166,927	166,927	166,927	166,927	166,927	166,927
Grant Reasonable	(1,417,612)	(103,163)	(103,163)	(103,163)	(282,824)	(103,163)	(103,163)	(103,163)	(103,163)	(103,163)	(103,163)	(103,163)	(103,163)
Subtotal Mid-Columbia Contracts	$ 4,236,278	$ 365,001	$ 365,001	$ 365,001	$ 185,339	$ 365,001	$ 365,001	$ 365,001	$ 365,001	$ 373,984	$ 373,984	$ 373,984	$ 373,984
Total Long Term Firm Purchases	$ 408,285,003	$ 38,112,901	$ 38,099,244	$ 38,462,675	$ 31,120,265	$ 30,218,459	$ 31,481,541	$ 33,992,925	$ 32,217,180	$ 30,415,760	$ 31,867,989	$ 33,914,391	$ 38,381,674

PACIFICORP
ACTUAL NET POWER COST REPORT
FOR THE YEAR ENDING DECEMBER 31, 2016

	Total	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	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
BPA Exchange	-	-	-	-	-	-	-	-	-	-	-	-	-
BPA FC II Wind	-	-	-	-	-	-	-	-	-	-	-	-	-
BPA FC IV Wind	-	-	-	-	-	-	-	-	-	-	-	-	-
BPA So. Idaho	-	-	-	-	-	-	-	-	-	-	-	-	-
Cowlitz Swift	-	-	-	-	-	-	-	-	-	-	-	-	-
EWEB FC I	-	-	-	-	-	-	-	-	-	-	-	-	-
PSCO FC III	-	-	-	-	-	-	-	-	-	-	-	-	-
PSCo 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
Redding Exchange	-	-	-	-	-	-	-	-	-	-	-	-	-
SCL State Line	-	-	-	-	-	-	-	-	-	-	-	-	-
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													
Short Term Firm Purchases	$ 117,416,777	$ 4,933,345	$ 3,627,299	$ 7,686,854	$ 8,670,419	$ 9,846,349	$ 15,379,368	$ 21,320,284	$ 19,340,719	$ 7,774,398	$ 4,007,841	$ 2,555,879	$ 12,274,022
EIM Settlements	(22,582,121)	604,168	(1,706,203)	(1,462,571)	2,792,857	3,470,091	2,401,012	(3,294,936)	(3,490,569)	(2,392,607)	(6,825,431)	(4,124,166)	(8,553,765)
Other Firm Purchases	(11,820,045)	(825,648)	336,697	(565,474)	(4,094,741)	(3,693,955)	(1,155,778)	(1,686,566)	(1,470,302)	33,993	3,476,798	1,088,672	(3,263,742)
Total Short Term Firm Purchases	$ 83,014,611	$ 4,711,866	$ 2,257,794	$ 5,658,808	$ 7,368,535	$ 9,622,485	$ 16,624,602	$ 16,338,783	$ 14,379,848	$ 5,415,784	$ 659,207	$ (479,616)	$ 456,515
Total Secondary Purchases	$ (59,408)	$ 9,445	$ 8,573	$ 23,019	$ 11,284	$ 5,984	$ (191,130)	$ 9,580	$ 21,269	$ 9,076	$ 10,447	$ 11,416	$ 11,629
Total Purchased Power & Net Interchai	**$ 496,640,205**	**$ 43,284,211**	**$ 40,815,611**	**$ 44,594,502**	**$ 38,950,084**	**$ 40,296,928**	**$ 48,365,014**	**$ 50,791,288**	**$ 47,068,297**	**$ 36,290,619**	**$ 32,987,643**	**$ 33,896,191**	**$ 39,299,817**

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	Total	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	$ 130,835,086	$ 11,026,147	$ 11,370,667	$ 10,857,904	$ 10,760,207	$ 11,337,041	$ 10,857,833	$ 10,723,376	$ 10,359,594	$ 10,254,072	$ 10,698,242	$ 11,306,964	$ 11,283,040
Non-Firm Wheeling	1,562,610	112,988	33,042	90,672	36,443	81,364	430,259	487,509	41,485	164,053	19,237	40,591	24,966
Total Wheeling & U. of F. Expense	**$ 132,397,697**	**$ 11,139,134**	**$ 11,403,710**	**$ 10,948,576**	**$ 10,796,650**	**$ 11,418,405**	**$ 11,288,092**	**$ 11,210,885**	**$ 10,401,080**	**$ 10,418,125**	**$ 10,717,479**	**$ 11,347,555**	**$ 11,308,007**
COAL FUEL BURN EXPENSE													
Cholla	40,212,229	4,874,100	3,339,034	1,240,952	509,595	1,967,516	6,535,216	5,210,408	4,667,920	2,774,104	3,389,651	1,133,368	4,570,366
Colstrip	15,479,263	1,354,679	1,125,515	1,193,641	1,345,516	501,361	817,784	1,559,022	2,643,108	1,513,287	1,680,366	919,564	825,420
Craig	20,278,713	1,400,365	1,193,579	1,859,941	1,934,876	1,876,131	1,879,712	1,882,232	2,017,430	1,157,058	1,181,383	1,984,759	1,911,249
Dave Johnston	57,806,147	5,340,248	4,119,272	3,837,015	4,310,208	5,157,811	4,757,965	5,372,246	4,513,799	4,733,257	4,810,480	5,283,636	5,570,212
Hayden	11,644,955	1,352,163	1,181,667	930,235	490,598	439,655	1,116,252	1,086,893	1,364,617	1,261,906	1,065,539	681,754	673,677
Hunter	131,013,496	13,869,687	10,023,133	6,438,076	7,974,624	7,095,316	10,959,868	12,942,377	12,700,772	11,651,890	11,524,419	12,918,945	12,914,388
Huntington	106,739,544	10,672,278	7,606,675	4,072,652	4,318,905	6,786,411	9,073,577	10,777,761	10,853,814	10,658,823	11,577,051	9,429,046	10,912,551
Jim Bridger	235,990,431	19,482,416	17,424,007	13,609,000	11,593,721	16,530,971	21,659,416	21,193,655	23,119,611	33,915,999	16,180,769	15,421,729	25,859,134
Naughton	109,685,635	10,606,070	9,519,833	9,392,156	6,958,719	5,821,760	7,718,973	9,637,449	9,572,479	10,414,749	10,375,772	9,518,443	10,149,231
Wyodak	22,800,742	2,162,659	2,168,404	2,209,826	1,229,518	(55,923)	27,732	2,274,935	2,738,187	2,560,329	2,556,067	2,447,286	2,481,723
Total Coal Fuel Burn Expense	**$ 751,651,155**	**$ 71,114,665**	**$ 57,701,117**	**$ 44,783,496**	**$ 40,666,280**	**$ 46,121,008**	**$ 64,546,496**	**$ 71,936,978**	**$ 74,191,738**	**$ 80,641,402**	**$ 64,341,497**	**$ 59,738,530**	**$ 75,867,950**
GAS FUEL BURN EXPENSE													
Chehalis	$ 46,297,239	$ 3,233,258	$ 2,812,613	$ 3,513,055	$ 2,571,285	$ 2,996,755	$ 3,759,694	$ 2,904,075	$ 4,181,072	$ 6,214,076	$ 3,903,534	$ 3,982,421	$ 6,225,402
Currant Creek	39,605,139	3,474,940	2,558,140	4,317,496	3,126,181	2,178,765	4,500,225	4,550,482	5,043,328	3,017,661	3,087,392	905,549	2,844,981
Gadsby	4,109,422	377	-	-	218,244	27,520	549,479	1,512,434	1,524,254	276,846	268	-	-
Gadsby CT	3,612,894	291,417	245,440	402,662	177,115	292,761	238,855	225,508	290,944	200,299	509,072	470,002	268,819
Hermiston	22,887,251	2,281,624	1,887,102	1,583,847	1,050,101	887,781	1,389,110	1,473,654	1,465,403	2,589,308	2,163,963	2,515,785	3,599,573
Lake Side 1	68,694,671	5,867,118	5,997,731	5,401,431	5,694,559	5,528,333	6,554,951	5,947,044	5,780,388	5,339,998	4,647,340	5,416,936	6,518,844
Lake Side 2	71,841,194	6,904,683	5,829,966	4,534,545	5,780,933	6,774,967	5,732,242	7,151,159	5,999,001	5,669,306	5,130,650	5,544,449	6,789,294
Total Gas Fuel Burn Expense	**$ 257,047,811**	**$ 22,053,416**	**$ 19,330,992**	**$ 19,753,035**	**$ 18,618,418**	**$ 18,686,881**	**$ 22,724,556**	**$ 23,764,356**	**$ 24,284,391**	**$ 23,307,494**	**$ 19,442,220**	**$ 18,835,141**	**$ 26,246,912**
OTHER GENERATION EXPENSE													
Blundell	$ 3,932,817	$ 310,082	$ 325,027	$ 311,509	$ 323,524	$ 300,870	$ 290,345	$ 252,676	$ 338,811	$ 207,894	$ 414,145	$ 447,151	$ 410,783
Total Other Generation Expense	**$ 3,932,817**	**$ 310,082**	**$ 325,027**	**$ 311,509**	**$ 323,524**	**$ 300,870**	**$ 290,345**	**$ 252,676**	**$ 338,811**	**$ 207,894**	**$ 414,145**	**$ 447,151**	**$ 410,783**
NET POWER COST	**$ 1,465,887,270**	**$ 127,266,973**	**$ 112,962,867**	**$ 111,624,599**	**$ 101,968,591**	**$ 107,913,172**	**$ 138,849,739**	**$ 143,442,166**	**$ 143,931,995**	**$ 134,512,872**	**$ 107,144,782**	**$ 105,543,529**	**$ 130,725,985**
Net Power Cost/Net System Load	$ 25.13	$ 24.28	$ 24.62	$ 24.69	$ 23.95	$ 24.04	$ 26.94	$ 25.69	$ 26.27	$ 29.30	$ 22.96	$ 24.30	$ 24.15

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	Total	Jan-16	Feb-16	Mar-16	Apr-16	May-16	Jun-16	Jul-16	Aug-16	Sep-16	Oct-16	Nov-16	Dec-16
								MEGAWATT-HOURS					
NET SYSTEM LOAD	**58,326,703**	5,240,910	4,588,634	4,520,310	4,257,841	4,488,623	5,154,105	5,583,552	5,478,218	4,591,319	4,666,147	4,343,880	5,413,165
SPECIAL SALES FOR RESALE													
Long Term Firm Sales													
Black Hills	252,508	16,560	16,452	15,790	15,745	17,407	18,480	25,736	30,902	27,115	23,468	17,826	27,027
BPA Wind	41,513	4,762	5,820	4,186	2,977	2,650	1,701	2,484	1,650	2,541	4,121	3,679	4,942
Hurricane Sale	246	19	19	19	18	20	21	23	23	21	22	20	21
LADWP (IPP Layoff)	122,424	52,674	49,076	20,674	-	-	-	-	-	-	-	-	-
SMUD	-	-	-	-	-	-	-	-	-	-	-	-	-
UMPA II	195,270	9,063	7,830	8,362	8,100	8,396	21,600	41,850	32,922	18,360	13,950	10,887	13,950
Total Long Term Firm Sales	611,961	83,078	79,197	49,031	26,840	28,473	41,802	70,093	65,497	48,037	41,561	32,412	45,940
Short Term Firm Sales													
Short Term Firm Sales	5,844,916	751,857	614,864	256,902	297,054	366,390	229,495	405,926	335,776	550,759	764,370	559,933	711,590
Other Firm Sales	173,881	17,367	14,939	17,412	14,881	13,257	16,500	16,862	14,415	12,071	11,655	7,822	16,700
Total Short Term Firm Sales	6,018,797	769,224	629,803	274,314	311,935	379,647	245,995	422,788	350,191	562,830	776,025	567,755	728,290
Total Secondary Sales	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Special Sales For Resale	**6,630,758**	**852,302**	**709,000**	**323,345**	**338,775**	**408,120**	**287,797**	**492,881**	**415,688**	**610,867**	**817,586**	**600,167**	**774,230**
Total Requirements	**64,957,461**	**6,093,212**	**5,297,634**	**4,843,655**	**4,596,616**	**4,896,742**	**5,441,903**	**6,076,433**	**5,893,906**	**5,202,185**	**5,483,733**	**4,944,047**	**6,187,395**

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	Total	Jan-16	Feb-16	Mar-16	Apr-16	May-16	Jun-16	Jul-16	Aug-16	Sep-16	Oct-16	Nov-16	Dec-16
PURCHASED POWER & NET INTERCHANGE													
Long Term Firm Purchases													
APS Supplemental	32,025	750	-	3,450	1,200	1,200	750	700	1,950	4,550	5,700	5,750	6,025
Combine Hills Wind	116,763	7,322	10,210	12,424	9,959	10,655	9,467	9,221	7,757	8,541	9,749	10,753	10,706
Deseret Purchase	280,826	26,753	10,625	21,701	23,862	-	25,863	27,355	36,494	24,838	22,658	24,418	36,259
Douglas PUD Settlement	62,384	440	2,998	7,538	8,943	10,227	7,640	5,054	3,572	2,425	5,561	6,137	1,849
Eagle Mountain - UAMPS/UMPA	87,508	6,198	5,481	7,067	5,010	8,318	9,581	9,256	7,914	7,944	6,724	6,020	7,995
Gemstate	51,838	-	-	-	-	5,343	14,637	15,812	16,046	-	-	-	-
Hermiston Purchase	547,251	117,191	125,790	112,970	67,608	53,438	67,772	2,483	-	-	-	-	-
Hurricane Purchase	1,949	229	222	165	133	113	103	184	225	198	132	110	136
IPP Purchase	122,424	52,674	49,076	20,674	-	-	-	-	-	-	-	-	-
MagCorp Reserves	-	-	-	-	-	-	-	-	-	-	-	-	-
Nucor	-	-	-	-	-	-	-	-	-	-	-	-	-
Old Mill Solar	9,015	-	-	268	757	813	1,519	1,694	1,511	1,182	584	421	266
Pavant III Solar	96	-	-	-	-	-	-	-	-	-	-	-	96
P4 Production	-	-	-	-	-	-	-	-	-	-	-	-	-
PGE Cove	11,941	1,014	966	1,013	990	990	990	1,014	1,014	990	954	992	1,014
Rock River Wind	145,833	17,916	15,939	14,028	11,442	8,740	5,990	8,387	5,782	9,412	15,253	12,904	20,039
Small Purchases east	366	31	52	33	29	26	27	28	31	26	26	26	30
Small Purchases west	-	-	-	-	-	-	-	-	-	-	-	-	-
Three Buttes Wind	333,872	41,931	40,696	35,128	22,409	19,587	16,701	16,600	18,258	22,819	32,136	29,059	38,548
Top of the World Wind	651,049	71,075	79,035	68,109	44,225	41,262	31,078	33,335	37,921	47,793	63,653	60,674	72,889
Tri-State Purchase	96,250	7,369	6,456	7,736	7,213	6,994	8,500	8,830	8,891	9,277	8,744	8,378	7,862
Wolverine Creek Wind	174,814	13,286	15,947	17,469	14,236	12,291	12,781	13,684	10,174	12,240	19,349	14,468	18,888
Subtotal Long Term Firm Purchase	2,726,204	364,179	363,493	329,774	218,016	179,996	213,399	153,636	157,539	152,235	191,223	180,111	222,603
Seasonal Purchased Power													
Constellation 2013-2016	122,979	-	-	-	-	-	-	39,771	43,133	40,000	75	-	-
Total Seasonal Purchased Power	122,979	-	-	-	-	-	-	39,771	43,133	40,000	75	-	-

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	Total	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	72,538	6,429	8,503	9,204	8,847	6,289	3,790	3,012	4,317	3,754	4,416	6,892	7,084
QF Idaho	134,914	9,240	9,092	11,347	11,113	13,466	16,015	12,119	10,122	9,461	10,902	11,927	10,110
QF Oregon	262,404	20,445	21,501	28,134	28,129	25,385	21,804	20,526	20,155	18,714	16,674	18,405	22,531
QF Utah	100,915	5,683	7,427	8,651	8,894	10,025	10,202	9,691	8,893	9,372	8,903	7,296	5,878
QF Washington	8,150	176	162	144	530	1,361	1,574	1,636	1,544	857	166	-	-
QF Wyoming	11,260	1,478	1,428	1,203	945	749	533	818	629	656	920	862	1,039
Biomass One QF	159,261	18,399	18,467	18,893	18,757	-	-	-	18,984	20,087	19,016	19,303	7,356
Chevron Wind QF	42,051	4,516	5,676	4,503	2,813	2,592	1,902	2,440	2,001	2,629	4,226	3,775	4,978
Chopin Wind QF	9,671	-	-	-	-	-	-	-	-	-	3,039	3,202	3,430
DCFP QF	4,974	24	248	389	514	452	596	464	218	636	673	479	281
Enterprise Solar I QF	140,268	-	-	-	-	6,526	22,355	28,593	21,539	21,333	16,319	13,314	10,288
Escalante 1 Solar QF	85,339	-	-	-	-	-	-	12,227	18,904	20,250	15,270	11,178	7,511
Escalante 2 Solar QF	94,435	-	-	-	-	-	-	20,968	20,475	20,169	14,354	11,002	7,467
Escalante 3 Solar QF	97,501	-	-	-	-	-	-	24,699	20,004	19,713	15,138	10,756	7,191
Evergreen BioPower QF	50,268	2,859	2,500	3,347	4,536	4,595	5,061	5,331	5,548	4,983	4,202	3,695	3,611
ExxonMobil QF	265	-	-	-	-	-	-	265	-	-	-	-	-
Five Pine Wind QF	85,952	7,101	9,393	11,111	9,833	7,225	8,297	8,891	5,139	-	-	7,625	11,338
Foote Creek III Wind QF	75,950	9,376	11,301	7,333	5,165	4,473	2,813	4,112	3,009	4,301	7,509	6,750	9,808
Granite Mountain East Solar QF	55,799	-	-	-	-	-	-	-	12,634	9,216	13,374	12,138	8,436
Granite Mountain West Solar QF	25,726	-	-	-	-	-	-	-	3,176	6,217	3,441	7,452	5,441
Iron Springs QF	114,477	-	-	-	-	-	20,239	17,852	20,386	19,179	15,630	12,391	8,799
Kennecott Refinery QF	-	-	-	-	-	-	-	-	-	-	-	-	-
Kennecott Smelter QF	-	-	-	-	-	-	-	-	-	-	-	-	-
Latigo Wind QF	111,184	-	5,435	10,989	11,151	9,621	10,775	9,993	7,413	11,528	10,147	14,079	10,053
Mountain Wind 1 QF	160,884	17,812	23,318	15,810	11,182	9,885	7,513	12,701	6,587	11,455	12,221	10,090	22,312
Mountain Wind 2 QF	211,253	22,567	29,788	21,252	14,709	12,615	10,596	16,722	9,151	15,480	17,258	12,513	28,603
North Point Wind QF	191,935	14,998	19,173	26,277	22,100	16,349	18,843	21,578	12,501	-	-	17,591	22,526
Oregon Wind Farm QF	152,543	7,298	11,042	15,341	15,275	17,647	13,754	16,168	13,595	13,871	11,247	6,758	10,548
Pavant II Solar QF	8,509	-	-	-	-	-	-	-	-	-	225	4,996	3,288
Pioneer Wind 1 QF	81,794	-	-	-	-	-	-	-	-	-	20,712	30,122	30,960
Power County North Wind QF	63,878	4,502	5,539	7,410	5,674	4,643	4,546	5,247	4,249	4,598	5,874	4,937	6,660
Power County South Wind QF	54,521	3,259	5,248	6,653	5,048	3,967	3,775	3,919	3,452	3,676	5,505	4,188	5,832
Roseburg Dillard QF	28,075	1,906	1,740	1,892	3,112	3,269	1,461	3,088	2,542	1,436	3,120	2,535	1,972
SF Phosphates QF	-	-	-	-	-	-	-	-	-	-	-	-	-
Spanish Fork Wind 2 QF	48,248	4,349	2,898	3,124	3,017	3,229	4,015	4,468	4,955	3,849	4,378	5,172	4,794
Sunnyside QF	400,996	38,540	35,836	37,101	10,852	31,951	37,843	37,682	38,867	30,122	33,035	36,664	32,503
Tesoro QF	19,573	1,773	1,444	2,273	1,770	3,293	471	351	533	1,197	2,105	1,940	2,422
Three Peaks Solar QF	8,842	-	-	-	-	-	-	-	-	-	-	-	8,842
Threemile Canyon Wind QF	20,700	855	1,239	1,959	2,389	2,726	2,339	2,244	1,633	1,604	1,156	1,253	1,303
US Magnesium QF	-	-	-	-	-	-	-	-	-	-	-	-	-
Utah Pavant Solar QF	109,951	4,241	6,096	7,942	10,048	12,758	13,960	14,082	11,418	11,189	7,951	6,773	3,493
Utah Red Hills Solar QF	208,081	10,077	15,475	17,130	17,649	22,433	24,168	25,285	20,355	19,818	16,158	12,084	7,448
Subtotal Qualifying Facilities	3,513,084	217,903	259,968	279,411	234,052	237,524	269,243	347,171	334,928	321,350	325,264	340,134	346,136
Mid-Columbia Contracts													
Douglas - Wells	248,655	20,179	19,556	23,046	23,266	23,070	24,099	21,068	19,425	13,885	15,459	20,625	24,977
Grant Surplus	91,474	8,493	8,430	9,805	8,057	6,701	8,720	8,150	7,204	5,432	5,264	5,209	10,009
Grant Reasonable	-	-	-	-	-	-	-	-	-	-	-	-	-
Subtotal Mid-Columbia Contracts	340,129	28,672	27,986	32,851	31,323	29,771	32,819	29,218	26,629	19,317	20,723	25,834	34,986
Total Long Term Firm Purchases	6,702,396	610,754	651,447	642,036	483,391	447,291	515,461	569,796	562,229	532,902	537,285	546,078	603,725

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	Total	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	(2,136)	142,655	69,078	-	-	(78,195)	(137,832)	(142,813)	(142,848)	(69,149)	78,336	138,159	140,473
BPA Exchange	-	-	-	-	-	-	-	-	-	-	-	-	-
BPA FC II Wind	-	-	-	-	-	-	-	-	-	-	-	-	-
BPA FC IV Wind	535	756	1,503	(2,336)	(1,855)	(798)	(1,098)	593	(342)	1,267	2,151	112	583
BPA So. Idaho	1,139	-	-	869	-	270	-	-	-	-	-	-	-
Cowlitz Swift	(22,369)	(15,240)	-	8,175	(6,671)	10,156	2,154	911	(7,284)	(4,549)	-	2,664	(12,685)
EWEB FC I	2,446	2,400	(35)	(1,205)	(230)	-	(340)	157	12	114	578	817	178
PSCO FC III	-	-	-	-	-	-	-	-	-	-	-	-	-
PSCo Exchange	3,415	-	84	99	(316)	1,831	163	252	(43)	397	484	104	360
Redding Exchange	-	-	-	-	-	-	-	-	-	-	-	-	-
SCL State Line	(4,272)	(8,572)	(6,038)	18,562	2,062	(4,835)	(1,369)	(5,445)	(6,780)	242	5,952	2,964	(1,016)
Total Storage & Exchange	(21,243)	122,000	64,592	24,163	(7,010)	(71,572)	(138,322)	(146,345)	(157,285)	(71,678)	87,501	144,820	127,893
Short Term Firm Purchases													
Short Term Firm Purchases	5,206,977	216,719	160,540	350,173	652,946	872,732	719,913	728,001	606,553	258,896	160,566	121,576	358,362
EIM Settlements	(536,922)	8,225	(12,349)	(11,529)	51,032	94,384	26,659	(144,869)	(148,064)	(91,954)	(71,619)	(61,036)	(175,801)
Other Firm Purchases	47,379	13,135	9,457	(17,931)	12,226	7,328	4,355	1,161	(2,663)	9,391	175,297	(157,382)	(6,995)
Total Short Term Firm Purchases	4,717,434	238,079	157,648	320,713	716,204	974,444	750,927	584,293	455,825	176,333	264,244	(96,842)	175,566
Total Secondary Purchases	(11,467)	(8,083)	(2,084)	(3,859)	1,057	(8,024)	(1,655)	6,382	5,001	(196)	(1,786)	946	832
Total Purchased Power & Net Interchai	**11,387,120**	**962,750**	**871,602**	**983,054**	**1,193,642**	**1,342,139**	**1,126,411**	**1,014,127**	**865,771**	**637,360**	**887,245**	**595,002**	**908,017**

PACIFICORP
ACTUAL NET POWER COST REPORT
FOR THE YEAR ENDING DECEMBER 31, 2016

	Total	Jan-16	Feb-16	Mar-16	Apr-16	May-16	Jun-16	Jul-16	Aug-16	Sep-16	Oct-16	Nov-16	Dec-16
COAL GENERATION													
Cholla	1,740,097	219,489	139,427	48,577	16,267	74,138	172,946	227,649	211,932	231,564	143,217	47,128	207,763
Colstrip	1,035,662	104,731	91,820	81,273	85,318	39,421	54,533	97,184	100,953	98,208	98,352	100,002	83,867
Craig	1,159,892	78,136	69,682	98,620	110,564	111,472	107,311	114,623	119,981	69,303	65,390	106,497	108,313
Dave Johnston	5,088,505	470,422	369,390	323,547	387,848	460,048	432,933	480,713	405,625	407,255	419,348	458,611	472,765
Hayden	494,248	56,638	46,332	37,684	18,171	17,901	45,199	53,169	55,292	55,005	50,183	29,171	29,503
Hunter	7,057,745	767,982	553,731	371,541	393,323	386,596	582,080	701,059	705,438	612,581	634,454	615,357	733,603
Huntington	5,503,890	530,954	430,229	214,101	222,608	339,429	463,280	561,689	554,794	545,191	594,738	489,651	557,226
Jim Bridger	8,017,176	778,316	674,744	451,513	341,052	494,817	704,902	884,476	957,051	654,570	615,508	568,547	891,680
Naughton	4,871,839	463,666	402,794	399,091	316,535	282,641	388,805	459,072	418,776	445,297	442,739	412,453	439,970
Wyodak	1,614,214	157,286	145,801	158,254	82,759	-	-	161,996	197,322	189,459	174,879	172,742	173,716
Total Coal Generation	**36,583,268**	**3,627,620**	**2,923,950**	**2,184,201**	**1,974,445**	**2,206,463**	**2,951,989**	**3,741,630**	**3,727,164**	**3,308,433**	**3,238,808**	**3,000,159**	**3,698,406**
GAS GENERATION													
Chehalis	1,420,028	83,293	46,709	111,236	49,109	76,069	121,680	76,789	141,574	242,979	135,520	151,769	183,301
Currant Creek	1,474,686	121,179	82,251	165,780	145,274	82,682	189,807	177,565	204,457	102,452	109,683	12,672	80,884
Gadsby	63,646	(395)	(356)	(375)	4,447	(373)	8,152	26,341	24,836	2,532	(394)	(355)	(414)
Gadsby CT	57,257	3,104	2,004	6,341	3,258	4,754	4,930	5,203	6,316	3,215	8,556	7,591	1,985
Hermiston	1,145,656	117,395	126,023	113,176	67,588	53,545	67,115	67,059	81,463	103,807	96,833	118,449	133,203
Lake Side 1	2,730,622	227,114	209,220	232,458	268,947	275,393	240,386	248,812	232,290	207,948	173,581	188,868	225,605
Lake Side 2	2,995,420	258,573	241,936	182,202	286,482	314,387	306,671	309,838	259,550	220,476	189,283	194,408	231,614
Total Gas Generation	**9,887,315**	**810,263**	**707,787**	**810,818**	**825,105**	**806,457**	**938,741**	**911,607**	**950,486**	**883,409**	**713,062**	**673,402**	**856,178**
HYDRO GENERATION													
West Hydro	3,547,092	362,856	415,319	517,706	324,098	267,507	188,097	144,502	125,122	116,745	331,617	393,526	359,997
East Hydro	296,333	7,908	13,738	26,110	37,236	38,242	31,883	43,177	37,471	20,393	10,294	14,230	15,651
Total Hydro Generation	**3,843,425**	**370,764**	**429,057**	**543,816**	**361,334**	**305,749**	**219,980**	**187,679**	**162,593**	**137,138**	**341,911**	**407,756**	**375,648**

PACIFICORP
ACTUAL NET POWER COST REPORT
FOR THE YEAR ENDING DECEMBER 31, 2016

	Total	Jan-16	Feb-16	Mar-16	Apr-16	May-16	Jun-16	Jul-16	Aug-16	Sep-16	Oct-16	Nov-16	Dec-16
OTHER GENERATION													
Blundell	256,918	23,745	22,709	22,376	15,577	22,602	19,731	19,860	21,682	20,915	22,430	22,637	22,654
Black Cap Solar	4,021	131	247	294	487	440	575	488	430	445	224	165	95
Dunlap I Wind	388,498	48,140	54,731	36,948	27,512	21,127	15,133	23,290	17,550	25,299	37,732	31,577	49,459
Foote Creek I Wind	108,681	12,469	15,237	10,959	7,796	6,937	4,452	6,503	4,321	6,651	10,786	9,631	12,939
Glenrock Wind	311,607	39,464	35,792	31,816	21,204	19,481	17,888	17,882	20,301	22,556	29,963	24,262	30,998
Glenrock III Wind	118,738	14,560	14,162	12,362	8,361	7,354	6,617	6,808	7,236	8,848	10,987	9,317	12,126
Goodnoe Wind	223,899	9,349	14,996	21,822	22,355	24,001	24,791	23,109	17,303	19,151	16,025	14,828	16,169
High Plains Wind	316,175	32,398	43,793	32,341	23,382	18,679	14,266	18,567	14,432	21,987	31,168	25,070	40,092
Leaning Juniper 1	202,605	6,995	9,754	17,568	22,205	25,266	25,094	21,567	17,809	18,025	12,006	12,024	14,292
Marengo I Wind	356,053	27,469	32,830	38,794	28,454	28,519	26,567	25,593	18,019	24,802	32,773	35,563	36,670
Marengo II Wind	170,369	13,574	16,775	19,479	13,132	13,429	12,086	10,901	9,207	12,398	15,712	16,590	17,086
McFadden Ridge Wind	95,925	9,630	13,348	9,115	6,521	5,767	4,443	6,058	4,710	6,682	9,960	7,760	11,931
Rolling Hills Wind	284,156	36,053	34,824	29,888	20,043	17,134	15,398	15,562	16,910	20,064	27,483	22,916	27,881
Seven Mile Wind	348,841	39,655	46,772	31,616	20,847	20,916	14,563	21,441	15,199	23,181	37,409	29,350	47,892
Seven Mile II Wind	69,847	8,183	9,268	6,388	4,214	4,282	3,178	3,761	2,783	4,841	8,049	6,038	8,862
Total Other Generation	**3,256,333**	**321,815**	**365,238**	**321,766**	**242,090**	**235,934**	**204,782**	**221,390**	**187,892**	**235,845**	**302,707**	**267,728**	**349,146**
TOTAL RESOURCES	**64,957,461**	**6,093,212**	**5,297,634**	**4,843,655**	**4,596,616**	**4,896,742**	**5,441,903**	**6,076,433**	**5,893,906**	**5,202,185**	**5,483,733**	**4,944,047**	**6,187,395**
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BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 323

In the Matter of	)
	)
PACIFICORP, dba PACIFIC POWER,	)
	)
2018 Transition Adjustment Mechanism.	)
	)

CONFIDENTIAL EXHIBIT NO. ICNU/104

ANALYSIS OF >7 DAY TRANSACTIONS IN DA/RT ADJUSTMENT

(REDACTED VERSION)

Confidential Exhibit ICNU/104 contains Protected Information subject to Order No. 16-128 and has been redacted in its entirety.