CASE: UE 296
WITNESS: JORGE ORDONEZ

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 100

Opening Testimony

June 29, 2015

Q. Please state your name, occupation, and business address.

A. My name is Jorge Ordonez. I am employed by the Public Utility Commission of Oregon (OPUC) as a Senior Economist in the Energy Resources and Planning Division. My business address is 201 High St. SE Suite 100, Salem, Oregon 97301-3612.

Q. Please describe your educational background and work experience.

A. My Witness Qualification Statement is found in Exhibit Staff/101.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to review PacifiCorp's (Pacific Power's or Company's) 2016 Transition Adjustment Mechanism (TAM) for Net Power Costs (NPC or NPCs) for the 2016 calendar year.

In conducting the aforementioned review, Staff referred to the Company's initial filing (Initial Filing or April 1 Filing)[1] and approximately 46 initial and follow-up data requests (DRs).

Q. Have you prepared an exhibit for this docket other than your witness qualification statement?

A. Yes, I have prepared Staff Exhibit/102 consisting of seven pages (exhibits related to a general description of PacifiCorp's filing); Exhibit/103 consisting of four pages (exhibits related to the modeling of the transmission transfer capability between PacifiCorp's east and west balancing authority areas); Staff Exhibit/104 consisting of four pages (exhibits related to Staff's energy imbalance market benefits review); and Staff Exhibit/105 consisting of seven

[1] See http://edocs.puc.state.or.us/efdocs/HAA/ue296haa15059.pdf

pages (exhibits related to the modeling change regarding day-ahead and real-time balancing transactions).

SUMMARY RECOMMENDATIONS

Q. What are your summary findings and recommendations?

A. Based upon the Company's filing, related DR responses, and Staff's analysis, Staff finds that PacifiCorp's 2016 TAM is not unreasonable with the exception of three issues:

- Modeling of the transmission transfer capability between PacifiCorp's east and west balancing authority areas (BAAs; BAAs Nexus Modeling);
- A certain portion of the Company's Energy Imbalance Market (EIM) benefits estimation (EIM Benefits); and
- A modeling change regarding day-ahead and real-time balancing transactions (Day-Ahead and Real-Time Modeling).

As for the BAAs Nexus Modeling, Staff recommends that the Company refine, if practicably possible, its BAAs Nexus Modeling in the Generation and Regulation Initiative Decision (GRID) model for the next TAM, preferably for the 2017 TAM. In the meantime, Staff continues to analyze this issue, and is developing a specific adjustment to provide in the next round of testimony that I expect to include the potential benefits of PacifiCorp being able to share reserves between its BAAs due to the availability of 400 MW of dynamic transfer capability between PacifiCorp's BAAs.[2]

[2] Staff has issued Staff DR 47 asking the Company to provide actual levels, if any, of reserves shared between its BAAs for the past three calendar years. From this information, Staff may run the GRID model to account for the potential level of reserves that the Company may share between its BAAs.

Regarding the EIM benefits, Staff recommends the inclusion of $1.43 million of Oregon-allocated benefits of reduced reserves due to the fact that EIM allows the Company to schedule wind resources on a within-hour basis.

Finally, regarding the Day-Ahead and Real-Time Modeling change, Staff recommends the Commission not accept the Company-proposed change, which results in reducing the Company's Oregon-allocated NPC by approximately $8 million. Although Staff understands the rationale behind the Company-proposed modeling change regarding the Day-Ahead and Real-Time Modeling, the complexity of the computational mechanics for implementing this modeling change presents challenges. Staff appreciates the computational support of PacifiCorp's GRID team in navigating the massive level of data in workbooks, worksheet, GRID inputs, etc. associated with this modeling change. However, Staff recommends that the Commission not adopt the Company-proposed modeling change until Staff and other parties have had the opportunity to reasonably understand the mechanics of the Company-proposed modeling, as well as the opportunity to analyze GRID runs' variances and sensitivities to the Company's proposed change. This could be facilitated through workshops before the next 2017 TAM, similar to the way in which parties participated in workshops covering the EIM benefits presented in this current 2016 TAM.

TESTIMONY ORGANIZATION

Q. How is your testimony organized?

A. My testimony is organized as follows:

I. GENERAL DESCRIPTION OF PACIFICORP'S FILING

Q. Please summarize PacifiCorp's 2016 TAM filing.

A. On a system basis, the Company's Initial Filing requested a 2016 NPC of approximately $1.53 billion,[3] which represents an increase of approximately $65 million compared to the 2015 NPC of $1.47 billion.[4]

Q. What is the effect on an Oregon basis?

A. On an Oregon basis, the 2016 NPC of approximately $378.0 million[5] is higher than the 2015 NPC of $366.2 million,[6] representing an $11.8 million or 3.2 percent increase[7] in NPCs. This represents an overall rate increase of approximately 0.9 percent.[8]

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[3] See line 39, column "TAM CY 2016," in Exhibit PAC/101, Dickman/1.
[4] See line 39, column "UE-287 Final TAM CY 2015," in Exhibit PAC/101, Dickman/1.
[5] This figure includes the "Other Revenue Change" of approximately $2.31 million represented in Exhibit PAC/101, Dickman/1, line 52.
[6] This figure includes $0.82 million in additional revenues due to load variance from UE-287 as represented in Exhibit PAC/101, Dickman/1, line 47.
[7] See Exhibit PAC/101, Dickman/1, line 54.
[8] See Exhibit PAC/404, Ridenour/1, line "Total Sales," column "Change-Net Rates-%."

Q. What are the major changes in costs in the 2016 NPC relative to the 2015 NPC?

A. As shown in Table 1, the increase in NPCs is driven mainly by a reduction in wholesale sales revenue and an increase in purchased power expenses.

Table 1[9]

	Total Company ($ million)	$/MWh
OR TAM CY 2015	**1,473**	**24.58**
[Increase (+) / decrease (-)] except as noted		
Wholesale Sales Revenue [reduction(+)/increase(-)]	*41*	
Purchased Power Expenses	*13*	
Coal Fuel Expenses	*4*	
Natural Gas Fuel Expenses	*2*	
Wheeling, Hydro and Other Expenses	*5*	
Total Increase (+)/Decrease (-)	*65*	
OR TAM CY 2015	**1,538**	**25.21**

Q. Please elaborate on the main drivers of the power cost increase (i.e., the reduction in wholesale sales revenue and the increase in purchased power expenses).

A. The reduction in wholesale sales revenue was driven by lower prices for wholesale market transactions. Market sales in the 2015 TAM were included at an average price of $35.25 per MWh, while market sales in the current TAM are included at an average price of $31.05 per MWh.[10]

Staff initially perceived a discrepancy between the Company's representation of $41 million above and the $38 million figure in Exhibit PAC/100, Dickman/7,

[9] See Exhibit PAC/100, Dickman/6.
[10] See Exhibit PAC/100, Dickman/7, lines 5-9.

lines 9-11. However, the Company clarified this in its response to Staff DR 4, wherein the Company represented that the $41 million figure included approximately $3 million of long-term sales revenue decrease and $38 million of short-term sales revenue decrease. The Company's response to Staff DR 4 is included in Exhibit Staff/102, Ordonez/1.

Q. Please explain the increase in purchased power expenses.

A. The increase in purchased power expenses is attributable mainly to the addition of 14 new power purchase agreements (PPAs) with qualifying facilities (QFs). These increases in purchased power expenses are partially offset by the expiration of two long-term PPAs: one for half of the output of the Hermiston power plant and the other for the output of a turbine located at the Georgia Pacific paper mill in Camas, Washington. The Company justified the inclusion of the QFs' 14 PPAs in response to Staff DR 5, which is included in Exhibit Staff/102, Ordonez/2-4. Staff initially had questions about the GRID modeling of the output of the turbine located at the Georgia Pacific paper mill, which was explained in the Company's response to Staff DR 6, included in Exhibit Staff/102, Ordonez/5-7. Staff also thought that the Company's assumption regarding this turbine was subject to OPUC approval of the transfer of this facility in Docket No. UP 325.[11] This assumption was confirmed

[11] Docket No. UP 325 is in the matter of PACIFICORP, dba PACIFIC POWER, Application for an Order Authorizing the Sale of Certain Assets to Georgia-Pacific Consumer Products LLC. See http://apps.puc.state.or.us/edockets/docket.asp?DocketID=19500.

after the OPUC issued Order No. 15-151 in Docket No. UP 325, entered on May 19, 2015, approving the sale of this facility.[12]

[12] See http://apps.puc.state.or.us/orders/2015ords/15-151.pdf.

II. BAAs NEXUS MODELING

Q. Please explain how PacifiCorp transfers power in real-life operations between its west and east BAAs.

A. As shown in Exhibit Staff/103, Ordonez/1,[13] Idaho Power owns 100 percent of three 345-kV transmission lines.[14] Under legacy agreements, PacifiCorp has 1,600 MW of transmission rights across those transmission lines, of which up to 200 MW could be dynamically scheduled.[15] However, this will change due to OPUC approval of the Company's request in Docket No. UE 315 (PacifiCorp and Idaho Power's Joint Application for an Order Authorizing the Exchange of Certain Transmission Assets).

Q. Please explain the Company's request in Docket No. UE 315 and how PacifiCorp's transfer of power will change due to this docket.

A. In Docket No. UE 315, PacifiCorp requested the exchange of certain transmission assets that, among other things, will result in PacifiCorp having ownership and wheeling rights of 1,600 MW, of which 400 MW could be dynamically scheduled across the three aforementioned transmission lines.[16]

Q. Has the OPUC approved the Company's request in Docket No. UP 315?

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[13] The source of this exhibit is Exhibit PAC/302, Vail/1 of Docket No. UP 315. Docket No. UP 315 is in the matter of PACIFICORP, dba PACIFIC POWER and IDAHO POWER COMPANY's Joint Application for an Order Authorizing the Exchange of Certain Transmission Assets (Jim Bridger Plant). See http://apps.puc.state.or.us/edockets/docket.asp?DocketID=19327.

[14] The three transmission lines comprise: one transmission line that extends from Kinport, Idaho to Midpoint, Idaho (Kinport to Midpoint), and two transmission lines that extend from Borah, Idaho to Midpoint, Idaho (Borah to Midpoint 1 and Borah to Midpoint 2).

[15] See Exhibit PAC/300, Vail/8, lines 12-18 of Docket No. UP 315, filed with the OPUC at http://edocs.puc.state.or.us/efdocs/HAA/up315haa141821.pdf.

[16] See Docket No. UP 315's Exhibit PAC/300, Vail/8, lines 21-23 and Exhibit PAC/300, Vail/9, line 1 at http://edocs.puc.state.or.us/efdocs/HAA/up315haa141821.pdf.

A. Yes. The Commission has approved the Company's request in Order No. 15-184.[17] Per the Company's filing in Docket No. UP 315, the transaction is expected to close on December 31, 2015.[18]

Q. What is dynamic scheduling?

A. Dynamic scheduling allows transfers of electricity between BAAs to be scheduled on an intra-hour basis (i.e., in fractions of the hour). In contrast, "static" scheduling is hour-to-hour scheduling not allowing scheduling changes during that hour.[19]

Q. What are the benefits of dynamic scheduling?

A. Unlike static scheduling that precludes mid-hour dispatch, dynamic scheduling allows electricity to be transferred within the hour so that, for example, a receiving BAA can depend on the delivery of energy with a very high level of certainty. As variable energy resources increase in a BAA, the ability to manage intra-hour electricity variability becomes increasingly important. Dynamic scheduling provides a least-cost mechanism for BAAs to help each other in managing variability.[20]

Q. Did the Company model any benefits of dynamic scheduling in its Initial Filing?

A. No. In response to Staff DR 3, part (d), which is included as Exhibit Staff/103, Ordonez/2-4, the Company represented that "GRID only optimizes the system

[17] See http://apps.puc.state.or.us/orders/2015ords/15-184.pdf.
[18] See page 8 of the Joint Purchase and Sale Agreement filed with the OPUC at http://edocs.puc.state.or.us/efdocs/HAA/up315haa141821.pdf.
[19] See page 5 of "Dynamic Transfers: Dynamic Transfers for Renewable Energy in the Western Interconnection Western Renewable Energy Zones Initiative - Phase III" at http://www.raponline.org.
[20] Ibid.

based on hourly average loads and resources, and does not ensure that transfer capability is adequate for all intervals in the hour [(within-hour)] or that the variation necessary over an hour can be accommodated using the Company's dynamic transmission rights."[21] In other words, any within-hour benefits resulting from the dynamic scheduling of 400 MW between PacifiCorp's BAAs were not considered in PacifiCorp's Initial Filing.

Q. Has Staff attempted to estimate the benefits of dynamic scheduling?

A. Yes. Staff ran a GRID scenario allowing reserves to be shared between the Company's BAAs beginning January 1, 2016.[22] However,[23] NPCs values did not change.[24] This may be a result of a modeling limitation that could be overcome by using a different level of reserves in other categories. Staff continues to explore this issue. Staff has issued Staff DR 47, requesting the Company to provide actual levels, if any, of reserves shared between its BAAs for the past three calendar years. Based on this information, for the next round of testimony, Staff intends to run a GRID scenario to account for the potential level of reserves that the Company may be able to share between its BAAs.

Q. Why is Staff interested in reflecting this benefit?

A. As mentioned earlier, when Pacific Power filed its request in Docket UP 315, the Company clearly identified this benefit (i.e., the increased dynamic transfer

[21] See the Company's response to part (d) of Staff DR 3, included in Exhibit Staff/103, Ordonez/3-4.
[22] In the GRID scenario, Staff used the input of 200 MW for "West Side Spinning Transfer Cap (MW)" and 200 MW for "West Side Ready Reserve Transfer Cap (MW)."
[23] The files of Staff's GRID run are in the folder titled "Run of transfer capability," provided in the confidential workpapers supporting this testimony.
[24] See the difference between cell E322 in workbook "_ORTAM16 NPC Study_2015 03 17 CONF (run transfer reserves)," worksheet "NPC" and cell E322 in workbook "_ORTAM16 NPC Study_2015 03 17 CONF (intact - as filed)," worksheet "NPC." Both files are provided to the Company in the confidential workpapers supporting this testimony.

capability between its BAAs) along with multiple other benefits.[25] When Staff recommended that the Commission approve the Company's request, Staff recognized these benefits and, therefore, such benefits should be reflected in this filing accordingly.[26]

[25] The multiple benefits are represented by the Company in Exhibit PAC/400, Duvall/1-2 at http://edocs.puc.state.or.us/efdocs/HAA/up315haa141821.pdf.
[26] See Order No. 15-184 adopting Staff report in Docket No. UE 315 at http://edocs.puc.state.or.us/efdocs/HAU/up315hau144750.pdf.

III. EIM BENEFITS

Q. Did Pacific Power estimate any EIM benefits in its Initial Filing of the 2016 TAM?

A. Yes. Staff acknowledges that the Company made notable and creative efforts to estimate the EIM benefits in its 2016 TAM fling. The Company identified the following benefits:

Table 2[27]
PacifiCorp EIM Benefits in 2016

Type of Benefit	2016 TAM System-wide Basis ($ Million)
Inter-regional dispatch	8.40
Intra-regional dispatch	N/A
Flexibility reserves	1.00
Within-hour dispatch	N/A
2016 test period benefits	**9.40**

Q. Please explain how the Company estimated the benefits associated with monetary values (i.e., inter-regional dispatch benefits and flexibility reserve benefits).

A. The inter-regional dispatch benefits reflect the savings associated with exporting and importing energy between Pacific Power's and the California Independent System Operator's (CAISO's) BAAs. The export benefit is the difference between the export revenue and the expense of the Company's generation that was dispatched to support the transaction. The import benefit is the difference between the import expense and the expense of the Company's

[27] Source: Table 2 in Exhibit PAC/100, Dickman/9.

generation that would have been dispatched in the absence of the transaction.[28]

The Company's forecasted EIM export and import benefits are derived from the results of EIM operation during December 2014 and January 2015, as reflected in the CAISO invoices and the cost of the Company's resources expected to be on the margin.[29]

Q. Please explain how the Company forecasted the flexibility reserve benefits

A. The flexibility reserve benefits were reflected by the Company reducing the regulating reserve requirement modeled in GRID to account for the Company's share of the reserve benefits based on the larger and more diversified footprint of the EIM. During December 2014, the Company's share of the reserve diversity benefit amounted to approximately 6 MW of reserves per 100 MW of EIM transfer capability, as calculated by the CAISO. This amounts to a reserve reduction of roughly 12 MW during the forecast period.[30]

Q. Please comment on these two kinds of benefits with monetary values (i.e., inter-regional dispatch benefit and flexibility reserve benefit).

A. Staff's general observation is that the Company's approach is not unreasonable. Staff looks forward to the Company's updates of these estimates based on additional historical information. As the Company represented in response to Staff DR 20, which is incorporated in Exhibit

[28] See Exhibit PAC/100, Dickman/16, lines 8-17.
[29] See Exhibit PAC/100, Dickman/16, lines 11-15.
[30] See Exhibit PAC/100, Dickman/19, lines 5-14.

Staff/104, Ordonez/1-2, PacifiCorp will update the estimates in its Reply Testimony on August 3, 2015, which will incorporate historical results for December 2014 through June 2015.

Q. Please explain why the Company designated the two other EIM benefits (i.e., intra-regional dispatch benefits and within-hour dispatch benefits) as not applicable.

A. The intra-regional dispatch benefits are the benefits of PacifiCorp optimizing its economic dispatch within the Company's BAAs. Since the GRID model has always assumed perfectly optimized hourly dispatch within PacifiCorp's BAAs, the intra-regional dispatch benefit is already incorporated in GRID.[31] Additionally, as represented in part (a) of the Company's response to Staff DR 13, which is included in Exhibit Staff/104, Ordonez/ 3-4, the "intra-regional perspective is restricted to the dispatch of PacifiCorp's generating units. Optimal dispatch occurs when the lowest cost generating units that can serve a given load are dispatched first, and generation from higher cost units is minimized… [and] no net saving can be achieved by backing down one unit and ramping up another unit."[32] Therefore, from the perspective of optimizing the economic dispatch in GRID on an hourly basis, no additional savings can be achieved.

Q. Please explain why the Company designated the within-hour dispatch benefits as not applicable.

[31] See Exhibit PAC/100, Dickman/11, lines 8-12.
[32] See part (a) of the Company's response to Staff DR 13, which is incorporated in Exhibit Staff/104, Ordonez/3-4.

A. As represented in part (b) of the Company's response to Staff DR 13, which is included in Exhibit Staff/104, Ordonez/3-4, the within-hour dispatch benefits are captured in the inter-regional dispatch benefits because the Company does not have access to any other within-hour electricity market besides EIM.

Q. Please comment on the two kinds of benefits that the Company has designated as not applicable (i.e., intra-regional dispatch benefits and within-hour dispatch benefits).

A. Staff's general observation is that the Company's approach is not unreasonable. However, one benefit associated with within-hour scheduling should be incorporated: the reduction of operating reserves in the form of regulating margin reserve, which provide capacity for reacting to changes in load and wind generation due to within-hour scheduling.

Q. What is a regulating margin reserve for Pacific Power?

A. Regulating margin reserve is the additional capacity that Pacific Power holds in reserve to make sure that the Company has adequate reserves at all times to meet NERC standards.[33] Regulating margin reserve responds to follow load and wind changes throughout the delivery hour.

Q. How did Staff estimate the benefits of reduced regulating margin reserve?

A. Staff's adjustment is based on the concept that when the Company schedules its net load (i.e., its load after accounting for intermittent resource generation, particularly wind) on a within-hour basis, there is less need for regulating margin reserves than when the Company schedules on an hour-to-hour basis.

[33] The standard directly applied to this requirement is NERC Standard BAL-001-2: Control Performance Criteria.

This was explained in the Company's wind integration study filed with the 2013 IRP (2013 Wind Study).[34]

The 2013 Wind Study recreated a 30-minute interval balancing scenario that resulted in a reduction in regulating margin reserves of 44 MW for the west BAA and 68 MW for the east BAA.

Q. What is the impact of this adjustment on the Company's proposed NPCs?

A. Staff ran a GRID scenario[35] incorporating this reduced level of regulating reserves that resulted in a system-wide NPC reduction of $5.56 million,[36] which represents a reduction of $1.43 million when expressed on an Oregon-allocated basis.

[34] See Exhibit H of PacifiCorp's 2013 IRP, Volume II, at http://www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Integrated_Resource_Plan/2013IRP/PacifiCorp-2013IRP_Vol2-Appendices_4-30-13.pdf.

[35] The files of Staff's GRID run are in the folder "Reduced Reserves," which is in the confidential workpapers in support of this testimony.

[36] See the difference between cell E322 in workbook "_ORTAM16 NPC Study_2015 03 17 CONF minus44west68east," worksheet "NPC" and cell E322 in workbook _ORTAM16 NPC Study_2015 03 17 CONF (Original)," worksheet "NPC". Both files are provided to the Company in the confidential workpapers in support of this testimony.

IV. DAY-AHEAD AND REAL-TIME MODELING

Q. Please explain the Company's proposed Day-Ahead and Real-Time Modeling change.

A. The Company proposes to modify in GRID the amounts of balancing purchases and sales, and to modify the forward market price curve.

Amounts of Balancing Purchases and Sales

Q. Please explain the proposed modification to the amounts of balancing purchases and sales.

A. The balancing sales volume (Sales Volume) was increased by 2.6 million MWh and the balancing purchases volume (Purchases Volume) was increased by an equal offsetting amount.[37]

Q. What is the Company's rationale for modifying the amounts of balancing purchases and sales?

A. The Company adjusted the amounts of balancing transactions to reflect the use of standard block products.[38]

Q. How does the GRID model currently balance load and resources?

A. The Company explained that the GRID model, as an economic dispatch model, calculates the least-cost solution to balance load and resources to fractions of a MW for each hour. The model makes purchases in the wholesale market (also called "balancing purchases") in the hours when the Company does not

[37] See Exhibit PAC/100, Dickman/20, lines 13-19.
[38] See Exhibit PAC/100, Dickman/23, lines 2-4.

have enough economic[39] owned or contracted resources to meet demand. GRID also makes sales in the wholesale market (also called “balancing sales”) when it has excess resources. GRID calculates these balancing transactions[40] for the precise volume needed in a particular hour.[41]

Q. How does the Company balance load and resources in real-life operations?

A. The Company described that, in actual operations, it continually balances its market position with monthly, then daily, and finally hourly products that are in flat 25-MW blocks.

The future monthly and daily positions (i.e., “short” position[42] and “long” position[43]) are estimated in advance. From this information, the Company buys products to cover its short position or sells products to address its long position. These buying and selling transactions are called “balancing” transactions. For example, after the Company has bought monthly products to balance its future month position, when any day of such future month approaches, the Company has to sell power if the amount of monthly products exceeded (unwinding the excess purchase) the need, or buy more power if the amount of monthly products was insufficient.

[39] By “economic,” Staff means that even though the Company may have plenty of owned or contracted resources available for dispatching in a particular hour, however such resources may be more expensive to operate relative to making wholesale purchases.
[40] By “transactions,” Staff refers to “purchases” and “sales.”
[41] See Exhibit PAC/100, Dickman/23, line 14.
[42] A “short” position is one in which the Company does not have enough resources to economically meet its demand.
[43] A “long” position means that the Company has excess resources to meet demand.

However, constant variation in the Company's load and resource balance results in the Company having to balance its position on an hour-to-hour basis.

Q. Please clarify the pertinent issues here.

A. There are two pertinent issues here: 1) the impact of the availability of flat 25-MW products, and 2) the impact of purchasing and selling products in advance.

Q. Do you agree with the Company's explanation regarding the first issue (i.e., the impact of the availability of flat 25-MW products)?

A. Yes. The GRID model, as an economic dispatch model, calculates the least-cost solution to balance load and resources to fractions of a MW for each hour; however, in actual operations, the Company continually balances its market position with flat 25-MW blocks. Therefore this actual feature of power markets should be reflected in the GRID if practically implemented.

Q. Do you agree with the Company's explanation regarding the second issue (i.e., the impact of purchasing and selling products in advance)?

A. Staff agrees that the Company has to make monthly and daily balancing purchases and sales in advance; however, the amounts proposed by the Company are not easily understood.

Q. Please explain why the amounts are not easily understood.

A. The Company estimated these amounts from a massive data set. Therefore, Staff struggles to understand how the Company estimated these amounts. For example, the GRID data from which the Company estimated the monthly, daily, and real-time balancing purchases and sales comprises approximately 1.25

million cells representing hourly purchases and sales for heavy load hours (HLH) and light load hours (LHL) for each market hub in which the Company trades electricity products (i.e., California-Oregon border or COB, Four Corners, Mead, Mid Columbia or Mid C, Mona, Nevada-Oregon border or NOB, and Palo Verde).[44] The complex formulas and tables used in the Company's worksheets are extremely challenging to decipher even for the Staff Senior Economist, who is a certified MS Excel user with more than ten years working with economic dispatch models.

Forward Market Price Curve

Q. Please explain the proposed modification of the forward market price curve.

A. The forward market price curve input in GRID (Forward Prices) is modified by generating two separate forward market price curves: 1) a forward market price curve for purchases (Purchase Forward Prices) and 2) a forward market price curve for sales (Sales Forward Prices).

Q. How do these two new forward market price curves (i.e., Purchase Forward Price and Sales Forward Price) differ from the plain Forward Prices?

A. The values of the Purchase Forward Prices are higher than those of the Forward Prices, and the values of the Sales Forward Prices are lower than those of the Forward Prices.[45]

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[44] See the confidential workbook, "ORTAM16 DA-RT_2015 03 17 CONF," worksheet "STF DA-RT Hourly," filed by the Company as workpapers for its Initial Filing.
[45] See Exhibit PAC/100, Dickman/28, lines 16-21.

Q. Please explain how GRID models the plain Forward Price.

A. The GRID model uses an hourly forward price curve developed from monthly HLH and LLH prices with hourly scalars applied. These scalars are the same within a given month for each weekday of that month.[46] Staff corroborated this fact by randomly reviewing the Forward Price for January 2016. In that month, the prices from 11:00 a.m. to noon for every weekday of the weeks of January 4, 11, 18, and 25 are identical. In another example, the electricity price for 11:00 a.m. to noon on Wednesday, January 6, 13, 20, and 27 are identical.[47]

Q. Please explain the Company's rationale for estimating new forward market price curves (i.e., Purchase Forward Price and Sales Forward Price).

A. Historically, the Company has bought more electricity during higher-than-average price periods in each month and sold more electricity during lower-than-average price periods. As a result, the average cost of the Company's daily and hourly short-term firm purchases has been consistently higher than the average actual monthly market price, while the hourly revenues from its daily and hourly short-term firm sales have been consistently lower than the average actual monthly market price.[48]

Q. Has the Company provided historical information to support its claim?

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[46] See Exhibit PAC/100, Dickman/25, line 12 and Dickman/26 line 1.
[47] See the confidential workbook "ORTAM16w_1412 OFPC (CY2016) with 3yr Avg Price Adder," worksheet "1412 OFPC (CY2016)," filed by the Company as the TAM Support Set 2. Specifically, see column "I".
[48] See Exhibit PAC/100, Dickman/26, lines 2-9.

A. Yes. The Company represented that in the 36 months that ended in June 2014, the Company's day-ahead and real-time transactions increased NPC by an average of $7.1 million per year compared to the historical monthly average market prices. Approximately $4.3 million of this impact was the result of higher-than-average purchase prices, while $2.8 million was due to lower-than-average sales prices.[49]

Q. Was Staff able to corroborate these figures?

A. Staff was unable to corroborate these figures for the reasons described above (Amounts of Balancing Purchases and Sales) in this testimony. The Company estimated these amounts from a massive data set. Therefore, Staff struggles to understand how the Company estimated these amounts. For example, as requested in Staff DR 39, which is included in Exhibit Staff/105, Ordonez/4, the Company estimated these values in the confidential MS Excel workbook "ORTAM16 BSD Direct NPC Testimony Support CONF.xlsx." That file, which is approximately 47 megabytes (MB) in size, gathers data from another MS Excel workbook, "ORTAM16w_1412 OFPC (CY2016) with 3yr Avg Price Adder.xlsx," which is approximately 22 MB in size. That workbook, in turn, gathers information from six other MS Excel files with sizes that range from 43 MB to 63MB each. Refreshing one file takes several minutes. These six files contain similar information that was divided among six files because Excel lacks the capacity to handle all of the cells in a single workbook.

[49] See Exhibit PAC/100, Dickman/26, lines 11-15.

Q. So, in summary, what is Staff's observation of each issue (i.e., that the plain Forward Price does not reflect the volatility of real time market prices, and the way in which the Company estimated the Purchase Forward Price and Sales Forward Price)?

A. Staff agrees that there is a need to address the fact that the Forward Price curve does not reflect constant variations in electricity prices. However, Staff does not understand the mechanism by which the Company intends to do so, for the reasons stated above.

Q. Has the Company assisted Staff in navigating the massive files referenced above?

A. Yes. Staff appreciates the assistance of the Company's GRID team, which has spanned multiple hours and days. Nevertheless, the extremely complex calculations are still not understood.

Conclusion

Q. What is Staff's position as of filing this opening testimony?

A. Staff generally agrees with the rationale for the Company's proposed modeling change. However, the means for implementing such a change is not clear. Therefore, at this point, Staff recommends that the Commission not adopt the Company-proposed modeling change until Staff and other parties have had the opportunity to reasonably understand the mechanics of the Company-proposed modeling, as well as the opportunity to analyze GRID runs' variances and sensitivities to the Company's proposed change. This could be facilitated through workshops before the next 2017 TAM, similar to the way in which parties participated in workshops covering the EIM benefits presented in this current 2016 TAM.

V. OVERALL CONCLUSION

Q. What is Staff overall conclusion?

A. Staff finds that PacifiCorp's 2016 TAM is not unreasonable with the exception of the following three issues, with their respective Staff-proposed adjustments:

- BAAs Nexus Modeling with an adjustment to be provided in the next round of testimony that I expect to include the potential benefits of PacifiCorp being able to share reserves between its BAAs due to the availability of 400 MW of dynamic transfer capability between PacifiCorp's BAAs.[50]
- EIM Benefits with the reduction of $1.43 million of Oregon-allocated NPC due to the benefits of reduced reserves that result from EIM allowing the Company to schedule wind resources on a within-hour basis.
- Day-Ahead and Real-Time Modeling with the reduction of $8 million of Oregon-allocated NPC.

Q. Would you like to address any other matters?

A. Staff anticipates that other parties to this docket may raise additional issues. Staff reserves the opportunity to testify in its next round of testimony

[50] Staff has issued Staff DR 47 asking the Company to provide actual levels, if any, of reserves shared between its BAAs for the past three calendar years. From this information, Staff may run the GRID model to account for the potential level of reserves that the Company may share between its BAAs.

regarding any additional issues or adjustments presented by an intervening party.

Q. Does this conclude your testimony?

A. Yes.

CASE: UE 296
WITNESS: Jorge Ordonez

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 101

Witness Qualification Statement

June 29, 2015

WITNESS QUALIFICATION STATEMENT

NAME	Jorge D. Ordonez
EMPLOYER	Public Utility Commission of Oregon
TITLE	Senior Economist, Energy Resources and Planning Division
ADDRESS	201 High St. SE Suite 100, Salem, Oregon 97301-3612
EDUCATION AND TRAINING	Utility Management Certificate Willamette University, Oregon, 2008
	Certificate in Management of Hydropower Development Swedish International Development Cooperation Agency, Sweden, 2006 & South Africa, 2007
	MBA, concentration in finance, Fulbright Scholar, Willamette University, Oregon, 2005
	Certificate in Project Appraisal and Management Maastricht School of Management, Netherlands, 2002
	BS, Mechanical Engineering, thermal power efficiency Electrical & Mechanical Engineering School San Antonio Abad University, Peru, 1998

EXPERIENCE

I received a Bachelors of Science degree in mechanical engineering from San Antonio Abad University in Cusco, Peru in 1998. Subsequently, as a Fulbright Scholar, I received an MBA with an emphasis in finance from Willamette University in 2005. From 1999 to 2008, I worked for a Peruvian power generation company and was promoted many times, working as an Engineer, Resource Scheduler, Manager of Economic Planning and Vice-President of Generation, Commercial and Trading. Since January 2009, I have been employed by the Public Utility Commission of Oregon as a Senior Financial Economist and earlier this year I was promoted to the position of Senior Economist. I am responsible evaluating utilities' issuance of securities, cost of capital, mergers and acquisitions, property sales, cost of service studies, marginal cost studies, rate spread and rate design, integrated resource plans, purchased gas costs, and power costs.

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 102

Exhibits in Support
Of Opening Testimony

(General Description of PacifiCorp's Filing)

June 29, 2015

OPUC Data Request 4

REDUCTION OF WHOLESALE SALES REVENUES - Regarding Table 1 in Exhibit PAC/100, Dickman/6, wherein the Company represented $41 million of Wholesale Sales Revenue decrease from the 2015 TAM,

And,

Regarding Exhibit PAC/100, Dickman/7, lines 9-11, wherein the Company represented: *"Revenue from market transactions is approximately $38 million lower on a total-company basis than in the 2015 TAM."*

Please:

Provide a comprehensive explanation of the difference between the $41 and $38 million of Wholesale Sales Revenue decrease referred above; please also provide a reconciliation of the amounts.

If the Company relied on information sources to formulate the responses to the above questions, please identify each such specific source and provide a copy of each such specific source document in portable document format (PDF) file(s), MS Word file(s), Excel workbook (with cell references and formulae intact) file(s), or any other common document format indicating the specific page, section, etc. of the relevant source document.

Response to OPUC Data Request 4

Referencing the Direct Testimony of Company witness, Brian S. Dickman, in Table 1 (Exhibit PAC/100, Dickman/6), the $41 million Wholesale Sales Revenue decrease includes approximately $3 million long-term sales revenue decrease, and $38 million short-term (market) sales revenue decrease. For more details, please refer to Mr. Dickman's confidential work papers provided concurrently with the filing; specifically the file entitled "ORTAM16 BSD Direct NPC Testimony Support CONF.xlsx" and the files linked to that file. The $41 million value is calculated in cell B8 of tab "Table 1." The $38 million figure is calculated in cell C18 of tab "Testimony Support."

UE 296/PacifiCorp
May 27, 2015
OPUC Data Request 5

OPUC Data Request 5

INCREASE IN POWER PURCHASE EXPENSE

Regarding Exhibit PAC/100, Dickman/7, wherein the Company represented:
"*The increase in purchased power expense is mainly attributable [to] the addition of 14 new power purchase agreements (PPAs) with qualifying facilities (QFs). As discussed later in my testimony, all of these PPAs are expected to reach commercial operation in 2016."*

Regarding Exhibit PAC/100, Dickman/43, wherein the Company represented:
"Q. *What type of information does the Company rely on to support the expected commercial operation dates for these contracts?*

" A. There are several <u>sources of information</u> [emphasis added]. First, the scheduled commercial operation date is set forth in the PPA for each project. As part of the negotiations, various milestones are included in the PPA that are documented and support the commercial operation date. Second, counterparties provide project status updates on a monthly basis that document progress toward milestones and the commercial operation date. Third, the Company monitors the status of the generator interconnection process, which is posted on the publicly available transmission provider's OASIS website, to ensure project output can be brought onto the Company's transmission system consistent with the commercial operation date."

Please:

(a) Provide a list of the 14 contracts referred in the first quotation in this data request including the main characteristics of each contract (e.g., capacity, energy, commercial operation date, etc.)

(b) For <u>each</u> of the 14 contracts referred in the first quotation in this data request, provide a copy of such contract;

(c) For <u>each</u> of the 14 contracts referred in the first quotation in this data request, provide copies of the documentation or *<u>sources of information</u>* (referred in the second quotation of this data request) upon which the Company relied to include such contract in the 2016 TAM;

(d) From the information provided in part "c" of this data request, for <u>each</u> of the contracts referred in the first quotation of these data request, please indicate in which document including page number there is information that support each criterion of the three-prone approach described in the second quotation of this data request for including such contract in the 2016 TAM; and

(e) Identify where in the Generation and Regulation Initiative Decision Tools model (GRID) files are the inputs of the 14 PURPA contracts modeled.

If the Company relied on information sources to formulate the responses to the above questions, please identify each such specific source and provide a copy of each such specific source document in portable document format (PDF) file(s), MS Word file(s), Excel workbook (with cell references and formulae intact) file(s), or any other common document format indicating the specific page, section, etc. of the relevant source document.

Response to OPUC Data Request 5

(a) The 14 qualifying facility (QF) power purchase agreements referenced in the Direct Testimony of Company witness, Brian S. Dickman (Exhibit PAC/100, Dickman/7) are listed below:

Large QF included in GRID individually:

- Chopin Wind – Oregon Schedule 37
- Blue Mountain Power (Wind) – Utah Schedule 38
- Enterprise Solar – Utah Schedule 38
- Escalante Solar I – Utah Schedule 38
- Escalante Solar II – Utah Schedule 38
- Escalante Solar III – Utah Schedule 38
- Pioneer Wind Park I – Wyoming Schedule 38
- Utah Red Hills Solar – Utah Schedule 38

Small QF included in GRID in aggregate by state:

- City of Astoria (Hydroelectric) – Oregon Schedule 37
- Beatty Solar – Oregon Schedule 37
- Sprague River Solar – Oregon Schedule 37
- Quichapa 1 (Solar) – Utah Schedule 37
- Quichapa 2 (Solar) – Utah Schedule 37
- Quichapa 3 (Solar) – Utah Schedule 37

For commercial operation date and capacity information, please refer to the Company's responses to subparts (c) and (e) below. For energy information, please refer to the Mr. Dickman's confidential work papers provided concurrently with the filing; specifically the file entitled "_ORTAM16 NPC Study_2015 03 17 CONF.xlsm" for the large facilities listed above, and Confidential Attachment TAM Support Set 2; specifically the file entitled "ORTAM16w_QF (1412) CONF.xlsx" for the small facilities.

(b) Please refer to TAM Support Set 3; specifically the confidential and non-confidential attachments beginning with “15-E..

(c) Please refer to Confidential Attachment OPUC 5 -1, Attachment OPUC 5 -2, Confidential Attachment OPUC 5 -3, and Attachment OPUC 5.4.

(d) Please refer to the Company’s response to subpart (c) above.

(e) The input data for the large QFs listed in subpart (a) above is provided in the following files, provided in Confidential Attachment TAM Support Set 2. The nameplate capacity of the contracts is located in the demand input file (“ORTAM16_Demand CONF.xlsx”), the purchase price is located in the energy charge input file (“ORTAM16_Energy Charge (1412) CONF.xlsx”), and the expected derate, used to adjust the nameplate capacity to the hourly expected output, is located in the EOR input file (“ORTAM16_EOR CONF.xlsx”).

The input data for the small QFs is entered in GRID in aggregate by state. For details by facility, please refer to Confidential Attachment TAM Support Set 2; specifically the file entitled “ORTAM16w_QF (1412) CONF.xlsx.”

The information provided in the Confidential Attachments is designated as confidential under the protective order in these proceedings and may only be disclosed to qualified persons as defined in that order.

OPUC Data Request 6

Regarding Exhibit PAC/100, Dickman/7, lines 16-19, wherein the Company represented:

"*Increases in purchased power expenses are partially offset by the expiration of two long-term purchase agreements, on for half of the output for the Hermiston power plant and the other for the output from a turbine located at the Georgia Pacific paper mill in Camas, Washington*".

Please:

(a) Provide a general explanation of how in the Generation and Regulation Initiative Decision Tools model (GRID) the Hermiston power plant is modeled; please also indicate where in the GRID files are the inputs for modeling of this plant;

(b) Provide an explanation of how by excluding one half of the output from the Hermiston power plant offsets the increases in purchased power expenses. For example, is the contract price for one half of the output of this plant out of the money relative to the forward electricity prices for the period where this contract is removed? As an additional example, is the contract price for one half of the output from this plant out of the money relative to the marginal unit for the period when this contract removed? Please explain;

(c) Provide a general explanation of how in GRID of the turbine located at the Georgia Pacific paper mill is modeled; please also indicate where in the GRID files the inputs for modeling this plant are located;

(d) Provide an explanation of how by excluding the output from of the turbine located at the Georgia Pacific paper mill offsets the increases in purchased power expenses. For example, is the contract price for the output of this plant out of the money relative to the forward electricity prices for the period where this contract is removed? As an additional example, is the contract price for the output from this plant out of the money relative to the marginal unit for the period when this contract removed? Please explain;

(e) Provide a comprehensive explanation whether or not the assumption of excluding from GRID the output from the turbine located at the Georgia Pacific paper mill is subject to the Public Utility Commission of Oregon (OPUC) approval of the Company's request in Docket No. UP 325, where the Company "seeks approval from the [OPUC] to sell an on-site generation unit and a 69 kilovolt (kV) transmission line to Georgia-Pacific Consumer Products (Camas) LLC (GP Camas)."[1]

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[1] See page 1 of the application in Docket No. UE 325, "In the Matter of PacifiCorp d/b/a Pacific Power Application for and Order Authorizing the Sale of Certain Assets to GP Camas" at http://edocs.puc.state.or.us/efdocs/HAA/haa16358.pdf

Response to OPUC Data Request 6

(a) The Hermiston plant consists of two units which are labeled “Hermiston 1 Owned” and “Hermiston 2 Owned” in Generation and Regulation Initiative Decision Tool (GRID) and the GRID input files. Despite the name, these resources represent both the owned and purchased shares of the Hermiston plant, prior to the expiration of the Hermiston Purchase agreement. Beginning July 1, 2016, only a 50 percent share of the Hermiston units is included in GRID. This treatment is the same as that of other shared units in the Company’s fleet.

The fuel costs, heat rate, and outage rate are contained within the following input data series provided in Confidential Attachment TAM Support Set 2: files entitled “ORTAM16_Fuel Price (1412) CONF.xlsx,” “ORTAM16_Heat Rate Coefficients CONF.xlsx,” and “ORTAM16_EOR CONF.xlsx.” The daily gas plant commitment (a.k.a. “screening”) is input to GRID via the file entitled “ORTAM16_Planned Outages CONF.xlsx.” The optimized commitment schedule is calculated in the screening files entitled “ORTAM16s_Screen - 8 HRM1 CONF.xlsx” and “ORTAM16s_Screen - 9 HRM2 CONF.xlsx.”

Other attributes of the Hermiston plant are input directly in the GRID database and are accessible from within GRID. Select the GRID project associated with the Company’s filing, and click “Process” next to the Company’s base net power costs (NPC) scenario ("_ORTAM16 NPC Study _2015 03 17 CONF”). Then export the “Thermal Attributes” report at the bottom left in the Input-Derived Extracts section. This report provides details on nameplate capacity, minimum operating level, reserve capability, and various other attributes of the thermal units modeled in GRID.

(b) The statement in the direct testimony of Company witness, Brian S. Dickman refers to the fact that long-term purchased power expenses are reduced once the contract to purchase half of the output for the Hermiston power plant expires (i.e. the Company will no longer incur this particular expense). The statement did not consider the impact on other categories of net power costs (NPC), such as short-term market purchases or the output of the marginal generating unit, due to the lost output from the Hermiston power plant.

(c) The Georgia Pacific (GP) Camas load and generation are located within the Company’s West Main transmission bubble. This means that the Company’s transmission rights allow for resources or transfers delivering in West Main to serve the GP Camas load. Because the contract terminates prior to the forecast period, no inputs for this resource are included in the current GRID study. For details on the GRID inputs from the prior case, please refer to Confidential Attachment OPUC 6.

(d) The statement in Mr. Dickman’s testimony was referring to the fact that long-term purchased power expenses are reduced once the contract to purchase the output from a turbine located at the GP Camas paper mill expires (i.e. the Company will no longer incur this particular expense). The statement did not consider the impact on other categories of NPC, such as short-term market purchases or the output of the marginal generating unit, due to the lost output from the GP Camas generator.

(e) The Company's forecasted load included in GRID assumes the Company continues to serve GP's net load requirements, under the expectation that GP takes possession of the generator and uses the output to offset its load. This treatment is consistent with the order in docket UP 325, where the commission approved PacifiCorp's application to sale certain assets, including the co-generation facilities, to GP.

The information provided in the Confidential Attachment is designated as confidential under the protective order in these proceedings and may only be disclosed to qualified persons as defined in that order

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 103

Exhibits in Support
Of Opening Testimony

(BAAs Nexus Modeling)

June 29, 2015

Existing Wheeling Rights

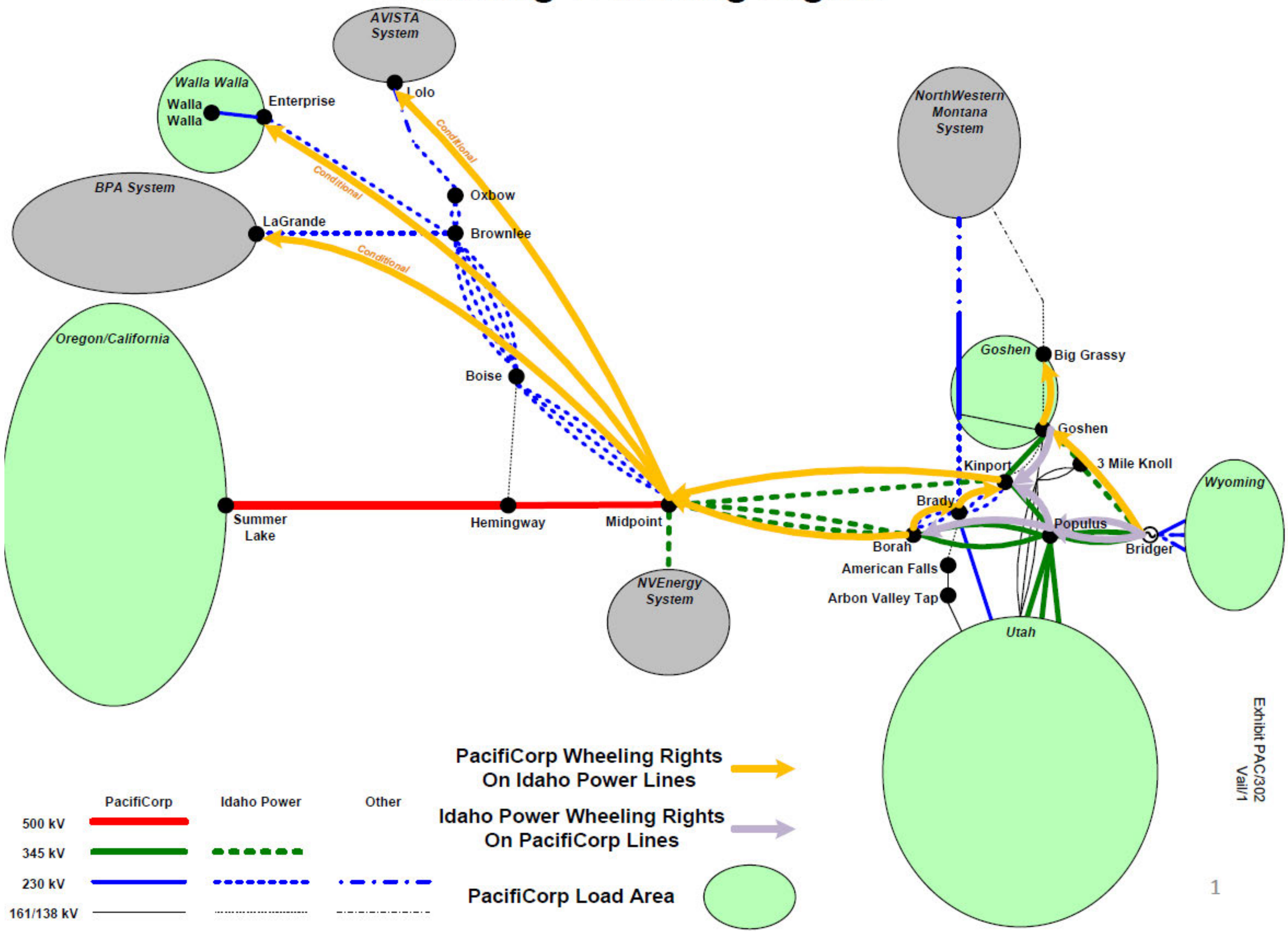

Exhibit PAC/302
Vail/1

Staff/103
Ordonez/1

OPUC Data Request 3

Regarding Exhibit PAC/300, Vail/8, lines 12-18, in Docket No. UP 315[1], wherein the Company represented:

"Q. What are PacifiCorp's transmission ownership and rights in the west of Kinport area prior to the transaction?

A. Idaho Power owns 100 percent of the three 345 kV lines, including one transmission line that extends from Kinport, Idaho to Midpoint, Idaho and two transmission lines that extend from Borah, Idaho to Midpoint, Idaho. Under the Legacy Agreements, PacifiCorp is allowed 1,600 MW of transmission service across the transmission lines, of which up to ***200 MW could be dynamically scheduled [emphasis added].***"

And,

Regarding Exhibit PAC/300, Vail/8, lines 19-23 and Vail/9, lines 1-4 in Docket No. UP 315, wherein the Company represented:

"*Q. What will PacifiCorp's transmission ownership and rights in the west of Kinport area be after the transaction?*

A. As detailed in the JPSA, PacifiCorp will have ownership rights and wheeling rights that it can use across all three transmission lines. Specifically, PacifiCorp will have 1,090 MW of ownership rights, plus 510 MW of firm OATT service, ***including 400 MW of dynamic service [emphasis added]****. PacifiCorp will be able to use a combination of point-to point transmission service rights over Idaho Power's system, and PacifiCorp network transmission service on newly owned assets, providing operational flexibility not afforded under the Legacy Agreements.*"

Please:

(a) Provide the transmission topology used in GRID for modeling all its system including the transmission links between PacifiCorp's east and west balancing authorities;

(b) For each transmission line or link modeled in GRID represented in part "a" of this date request, please provide the transmission capacity value assumed in GRID (Modeled Transmission Capacity) including an explanation of the type of transmission capacity (e.g., dynamic transmission capacity);

(c) For each transmission line or link modeled in GRID represented in part "a" of this data request, please explain how the Modeled Transmission Capacity values provided

[1] Docket No. UP315 is in the Matter of PACIFICORP, dba PACIFIC POWER and IDAHO POWER COMPANY's Joint Application for an Order Authorizing the Exchange of Certain Transmission Assets (Jim Bridger Plant).

in response "b" of this data requests differs with the actual/real transmission ratings of such transmission line (Actual/Real Transmission Capacity);

(d) Provide an explanation of how much DTC between its east and west balancing authorities the Company assumed in GRID; for example, if the Company used the 200 MW of DTC referred in the first quotation above, please explain why not the 400 MW of DTC referred in the second quotation above; and

(e) Provide a copy of the BPA South Idaho Exchange agreement or contract;

If the Company relied on information sources to formulate the responses to the above questions, please identify each such specific source and provide a copy of each such specific source document in portable document format (PDF) file(s), MS Word file(s), Excel workbook (with cell references and formulae intact) file(s), or any other common document format indicating the specific page, section, etc. of the relevant source document.

Response to OPUC Data Request 3

(a) Please refer to Confidential TAM Support Set 2, specifically the files "ORTAM16w_Transmission Topology Map CONF.pptx" and "ORTAM16w_Transmission Topology CONF.xlsx," for the topology map and transmission capacity details, respectively. Note: the Generation and Regulation Initiative Decision Tool (GRID) has hourly granularity and does not differentiate between static and dynamic scheduling rights.

(b) Please refer to the Company's response to subpart (a) above.

(c) Each transmission line or link modeled in GRID represents transfer capability owned by or allocated to PacifiCorp and available for the use of the PacifiCorp merchant function. The components of PacifiCorp's merchant function rights are listed in separate rows within the "POR–POD" link capacity with positive values. In some "POR-POD" links, PacifiCorp's merchant function rights are derated for reasons which include encumbrances due to another party's scheduling rights, derates to accommodate reserve carrying capability, or derates due to historical outage rates on paths that are typically derated by transmission providers.

Actual/real transmission ratings of these transmission lines or links may vary from what is modeled in GRID for reasons such as transmission reliability margins, ownership or allocation of capacity to other transmission customers, or capacity not purchased by PacifiCorp's merchant function.

(d) GRID does not constrain transfers based on static or dynamic transmission rights, and therefore does not restrict dynamic transfer capability to either 200 megawatts (MW) or 400 MW. GRID only optimizes the system based on hourly average loads and resources, and does not ensure that transfer capability is adequate for all intervals in the hour or that the variation necessary over an hour can be accommodated using the Company's dynamic transmission rights.

(e) Please refer to the Company's response to OPUC Data Request 12, subpart (a).

PUBLIC UTILITY COMMISSION
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STAFF EXHIBIT 104

Exhibits in Support
Of Opening Testimony

(EIM Benefits)

June 29, 2015

OPUC Data Request 20

Regarding Exhibit PAC/100, Dickman/13, lines 9-12, wherein the Company stated:

"The EIM benefit estimates and data to support those estimates will be improved with additional experience, and the Company intends to update the calculations during this case to include more historical results."

Please:

(a) As of the date of responding this data request, provide a more detailed explanation and examples of the "additional experience" that PacifiCorp mentioned in the above quotation; and

(b) As of the date of responding this data request, indicate when does PacifiCorp anticipate providing updates of its calculations during this case to include more historical results (e.g., Rebuttal Update Filing, Final Update Filing, etc. per the guidelines approved in Order No. 09-274 of Docket No. UE199); please indicate which historical months PacifiCorp intends to include in each of its proposed updates.

Response to OPUC Data Request 20

(a) "Additional experience" refers to: Energy Imbalance Market (EIM) model framework (California Independent System Operator (CAISO) responsibility) and EIM model inputs (PacifiCorp responsibility). The EIM model framework improved with additional experience. For example CAISO proposed an enhancement to prevent modeled infeasible solutions by including previously excluded capacity that is available and critical for system balancing but not available for economic EIM dispatch, such as run-of-river hydro resources. The EIM model inputs also improved with additional experience. For example, hydro resources had operational characteristics updated to more accurately reflect operational reality and allow for market solutions across the entire range of operation.

"Additional experience" also refers to the additional historical results available since the Company's filing was prepared. These results provide the following potential improvements.

- The Company's reserve diversity benefit appears to follow a daily pattern as a result of load and congestion within the CAISO, rather than the flat reserve value incorporated in the Company's initial filing.

- The inter-regional benefit is based on the margin between export revenues or import expenses on transfers to and from the CAISO and the generation cost of the resource dispatched up or down to accommodate the transfer. The Company's initial filing calculated the associated generation cost based on a limited pool of

PacifiCorp resources. The Company is continuing to gather and review data related to the incremental impact of EIM transfers.

(b) The Company's net power costs (NPC) update will be filed with its Reply Testimony on August 3, 2015, per the schedule in this docket. The Company anticipates incorporating historical results for December 2014 through June 2015 in that filing.

OPUC Data Request 13

ENERGY IMBALANCE MARKET (EIM) - Regarding Table 2 in Exhibit PAC/100, Dickman/9, wherein PacifiCorp described the benefits of EIM (i.e., inter-regional benefits, intra-regional benefits, flexibility reserves, and within-hour dispatch)[1] and further represented the following regarding the intra-regional benefits:

"*The GRID NPC forecast already reflects the optimized (i.e., lowest cost) dispatch of PacifiCorp's generating units within its two BAAs, so there are no additional benefits from EIM optimized dispatch (i.e., **intra-regional** [emphasis added] and **within-hour** [emphasis added] dispatch benefits).*[2]"

And,

Regarding Exhibit PAC/100, Dickman/11, lines 9-12, wherein the Company represented: "*The GRID model has always assumed perfectly optimized hourly dispatch within PacifiCorp's BAAs (i.e., intra-regional dispatch) and does not reflect any intra-hour imbalance or intra-hour dispatch costs (i.e., within-hour dispatch).*"

Please:

(a) In the context of the first quotation above, provide a comprehensive explanation strictly from the **"intra-regional"** point of view of how the GRID NPC forecast already reflects the optimized dispatch of PacifiCorp's generating units within its two BAAs so there are no additional benefits from EIM optimized dispatch;

(b) In the context of the first quotation above, provide a comprehensive explanation strictly from the **"within-hour"** point of view of how the GRID NPC forecast already reflects the optimized dispatch of PacifiCorp's generating units within its two BAAs so there are no additional benefits from EIM optimized dispatch; and

(c) Based on the Company's response to part "b" of this data request, please reconcile such response with the Company's statement of the second quotation above (i.e, GRID model has always assumed perfectly optimized hourly dispatch within PacifiCorp's and does not reflect any **intra-hour** imbalance or **intra-hour** dispatch costs).

Response to OPUC Data Request 13

(a) The intra-regional perspective is restricted to the dispatch of PacifiCorp's generating units. Optimal dispatch occurs when the lowest cost generating units that can serve a given load are dispatched first, and generation from higher cost units is minimized. The Generation and Regulation Initiative Decision Tool (GRID) employs a linear

[1] See Table 2 of Exhibit PAC/100, Dickman/9.
[2] See Exhibit PAC/100, Dickman/12, lines 19-22.

program optimization—i.e., optimal dispatch—constrained by: transmission capacity, thermal discretionary availability, purchases and sales market caps, and net load requirements. The GRID result is optimal within these constraints, that is, no net savings can be achieved by backing down one unit and ramping up another unit. The Energy Imbalance Market (EIM) does not create any benefits additional to GRID because the EIM does not relieve any of the constraints on the GRID linear program optimization (i.e., transmission capacity, thermal discretionary availability, purchases and sales market caps, and net load requirements).

(b) The within-hour benefit from EIM exports and imports is captured in the inter-regional benefit analysis. The within-hour optimization described here is restricted to the dispatch of PacifiCorp's generating units because the Company does not have access to any other within-hour electricity market besides EIM.

GRID is an hourly model and contains hourly values for load, wind, solar, prices and other inputs. GRID produces optimized generation dispatch, transmission schedules, and market transactions given these hourly inputs. In reality, market prices and transactions, and static transmission schedules are fixed for the entire hour, while load, wind, and solar vary continuously. These within-hour changes in load and wind must be met with the Company's generation resources. The generation changes needed to balance the continuous changes in load, wind, and solar over an entire hour result in higher costs relative to a static, perfectly-optimized, hourly schedule as contained in GRID. Since these costs are not included in GRID there are no additional benefits from EIM optimized dispatch relative to the GRID model.

(c) GRID reflects perfectly optimized costs for an hourly period assuming load net of wind and solar generation remains unchanged at a single level for the whole hour. In reality, this optimal solution is valid only if load net of wind and solar generation is equal to that hourly average, whether for the entire hour, or some limited portion of it.

When load net of wind and solar generation is lower than the hourly average, the Company's generation must be backed down, even if higher cost market transactions are the incremental resource in GRID. When load net of wind and solar generation is higher than the hourly average, the Company's next available generation capacity will be dispatched up, again even if market transactions are the incremental resource in GRID. Whether viewed from an hourly or within-hour granularity, resources are optimally dispatched based on the ranking of their marginal cost. Because of this optimization, when the supply stack results in resources with different marginal costs being backed down and dispatched up over the course of the hour, the sum of the within-hour dispatch costs will always be higher than the dispatch calculated using the hourly average requirement. The GRID result does not include these additional within-hour costs because it does not include the within-hour variation in requirements or the constrained set of resources available to accommodate those changes.

PUBLIC UTILITY COMMISSION
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STAFF EXHIBIT 105

Exhibits in Support
Of Opening Testimony

(Day-Ahead and Real-Time Modeling)

June 29, 2015

OPUC Data Request 37

MODELING CHANGES - Regarding the Company's proposed modeling change of previously unrecognized costs related to day-ahead and real-time balancing transactions (Day-Ahead & Real-Time Balancing Costs) that results in a 2016 TAM NPC increase of approximately $8 million, please respond the following questions:

(a) Is the $8 million figure a system-wide basis figure or an Oregon-allocated basis figure?

(b) Provide a breakdown of the Day-Ahead & Real-Time Balancing Costs into the **day-ahead** balancing costs and into **real-time** balancing costs;

(c) Provide a comprehensive explanation whether or not the **real-time** portion of the Day-Ahead & Real-Time Balancing Costs is already accounted when the Company estimates the EIM costs that result in the EIM net benefits[1] (net benefits = gross benefits minus costs) as represented in Table 2 of Exhibit PAC/100, Dickman/9. Staff question is based on the Company's representation in Exhibit PAC/100, Dickman/10, lines 8-10, that "[t]he EIM is a **real-time** balancing market that optimizes generator dispatch every five and 15 minutes…"

Response to OPUC Data Request 37

(a) The referenced change is on an Oregon allocated basis. For more details, please refer to the file entitled "ORTAM16 BSD Direct NPC Testimony Support CONF.xlsx" provided in the confidential work papers supporting the Direct Testimony of Company witness, Brian S. Dickman.

(b) The Company has not prepared a breakout of these costs between day-ahead and real-time periods; however, the source data on which the referenced figures are based contains the necessary details. Please refer to Confidential Attachment TAM Support Set 2; specifically the file entitled "ORTAM16w_1412 OFPC (CY2016) with 3yr Avg Price Adder.xlsx" and files linked to that file.

(c) "Real-time" with respect to the Day Ahead and Real-Time Balancing Costs refers to short-term firm (STF) transactions for one or more whole hours, executed on at least an hour-ahead basis. Hour-ahead transactions represent the Company's last opportunity to adjust its transmission schedules for any expected changes in loads and resources in an upcoming hour. Because these transactions are for hourly products,

[1] By "net benefits" Staff refers to the fact that the Company calculated some benefits by first calculating benefits and then subtracting the associated costs of such benefits. For example, as for the "Inter-Regional Dispatch Benefit," the Company estimated such benefits as follows: "[t]he export benefit is the difference between the export revenue and the expense of the Company generation that was dispatched to support the transaction. The import benefit is the difference between the import expense and the and the expense of the Company generation that would have been dispatched but for the transaction."

they are distinct from the costs and benefits associated with the Energy Imbalance Market (EIM), which optimizes generator dispatch over five minute and 15 minute intervals through the use of a limited set of transmission paths over which the Company has dynamic scheduling rights.

OPUC Data Request 38

Referring to Exhibit PAC/100 Dickman/26, the Company states that it has historically bought more during higher-than-average price periods and sold more during lower-than-average price periods. Please provide data for the years 2007-2014 to support this assertion.

Response to OPUC Data Request 38

The Company relies on data from July 2011 through June 2014 to support this assertion. For details, please refer to Confidential Attachment TAM Support Set 2; specifically the tab entitled “Adders” in the file entitled “ORTAM16w_1412 OFPC (CY2016) with 3yr Avg Price Adder.xlsx”, as well as files linked to that file.

For a summary of data from 2009 through June 2011 and July 2014 through December 2014, please refer to Confidential Attachment OPUC 38 -1. For details, please refer to Confidential Attachment OPUC 38 -2 through Confidential Attachment OPUC 38 -7. The Company has not examined data for earlier periods.

The information provided in the Confidential Attachment is designated as confidential under the protective order in these proceedings and may only be disclosed to qualified persons as defined in that order.

OPUC Data Request 39

Referring to Exhibit PAC/100, Dickman/26, the Company states that the NPC increased by $7.1 million per year over 36 months. Please provide the NPC increase on a monthly basis for each of the 36 months.

Response to OPUC Data Request 39

The referenced change is on an Oregon allocated basis.

For details, please refer to the file entitled "ORTAM16 BSD Direct NPC Testimony Support CONF.xlsx" provided in the confidential work papers supporting the Direct Testimony of Company witness, Brian S. Dickman. For the monthly detail, please refer to Confidential Attachment TAM Support Set 2; specifically the file entitled "ORTAM16w_1412 OFPC (CY2016) with 3yr Avg Price Adder.xlsx."

OPUC Data Request 40

Referring to Exhibit PAC/100, Dickman/28, the Company states that it has incorporated separate prices for purchases and sales in GRID. Please provide the complete dataset representing these revised purchases and sales.

Response to OPUC Data Request 40

Please refer to Confidential Attachment TAM Support Set 2; specifically the file entitled "ORTAM16w_1412 OFPC (CY2016) with 3yr Avg Price Adder.xlsx" and files linked to that file.

OPUC Data Request 41

Referring to Exhibit PAC/100, Dickman/30, the Company claims the modeling change for purchases and sales results in an increase of $8.0 million to NPC. Is this on a company-wide basis or an Oregon allocated basis?

Response to OPUC Data Request 41

Please refer to the Company’s response to OPUC Data Request 37, subpart (a).

OPUC Data Request 42

Referring to Exhibit PAC/200, Graves/3, please provide the source(s) for the values in Figure 1. If the figures are calculated or derived, please provide the input data used for the calculation, the source of the input data, and an example of the methodology used to calculate the value.

Response to OPUC Data Request 42

Please refer to Confidential Attachment OPUC 42.

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