Docket No. UE 263
Exhibit PAC/1200
Witness: Joelle R. Steward

**BEFORE THE PUBLIC UTILITY COMMISSION**

**OF OREGON**

**PACIFICORP**

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**Direct Testimony of Joelle R. Steward**

**March 2013**

# DIRECT TESTIMONY OF JOELLE R. STEWARD

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## ATTACHED EXHIBITS

**Q. Please state your name, business address, and present position with PacifiCorp d/b/a Pacific Power (PacifiCorp or Company).**

A. My name is Joelle R. Steward. My business address is 825 NE Multnomah Street, Suite 2000, Portland, Oregon 97232. My present position is Director, Pricing, Cost of Service, and Regulatory Operations.

## QUALIFICATIONS

**Q. Briefly describe your education and professional experience.**

A. I have a Bachelor of Arts degree in Political Science from the University of Oregon and a Masters of Public Affairs from the Hubert Humphrey Institute of Public Policy at the University of Minnesota. Between 1999 and March 2007, I was employed as a Regulatory Analyst with the Washington Utilities and Transportation Commission. I joined the Company in March 2007 as the Regulatory Manager responsible for all regulatory filings and proceedings in Oregon. I assumed my current position in February 2012, in which I direct the work of the cost of service, pricing, and regulatory operations groups.

## PURPOSE AND SUMMARY OF TESTIMONY

**Q. What are your responsibilities in these proceedings?**

A. I am responsible for the design of the Company's proposed prices in this proceeding. The proposed tariffs incorporate the Company's proposed price increase and are designed consistent with the Commission's rules under OAR 860-038-0200. I am sponsoring the Company's Oregon electric tariff schedules submitted for approval in this filing. Exhibit PAC/1201 contains the proposed tariffs.

**Q. Please summarize your testimony.**

A. The overall rate increase proposed by the Company in this case, including the effect of rebalancing the Rate Mitigation Adjustment (RMA) (discussed later in my testimony), is $56.2 million. However, after reflecting the effect of the implementation of Schedule 80, Transmission Investment Adjustment, for the Mona-to-Oquirrh transmission project in 2013, the overall proposed increase to customer bills as a result of this general rate case will be $44.8 million or 3.7 percent effective January 1, 2014. The Company is proposing a base rate spread that is consistent with the cost of service study in this case. Including the effect of all tariff riders, the Company's proposed net rate spread proposes continued use of the RMA to achieve a rate increase on January 1, 2014, where no customer rate class will see a rate increase more than 6.5 percent.

For rate design, in compliance with Order No. 12-500 the Company has included a new unbundled rate element in all non-direct access delivery service rate schedules—the System Usage Charge—to identify the franchise fee costs that would be avoided by any customer taking direct access. For residential rates, the Company is proposing a monthly basic charge of $10, which is a $1 increase to the current charge. For commercial and industrial rates, the Company is proposing increases to demand charges in Schedule 200 to better reflect cost of service results. Lastly, the Company is proposing separate treatment for the collection of the Lake Side 2 natural gas-fired generating plant (Lake Side 2) investment, which would take effect when the plant goes into service in the second quarter of 2014.

**ALLOCATION OF THE FUNCTIONALIZED REVENUE REQUIREMENT**

**Q. How is the Company proposing to allocate the functionalized revenue requirement across classes of customers in this proceeding?**

A. The Company is allocating the functionalized revenue requirement to classes consistent with the Commission's rules for Direct Access Regulation in OAR 860, Division 38. The rules indicate that rates are to be based on cost. As stated in OAR 860-038-0240(3)(b), "rates for any class of consumer must be based on the unbundled costs to serve that class." In this filing, the Company has allocated the revenue requirement to each rate schedule based on the results of the functionalized class cost of service study sponsored by Mr. C. Craig Paice. The proposed rates for each rate schedule included in the cost of service study are targeted to collect the cost of service for that rate schedule in the test period. Therefore, the proposed base rates for each class are based on the unbundled costs to serve that class.

**Q. Do you have an exhibit that summarizes the functionalized results of the cost of service study presented by Mr. Paice?**

A. Yes. Exhibit PAC/1202, Steward/1-2, summarizes the functionalized results of the cost of service study in column (4). This summary is provided at the level used to design rates. The cost of service for each rate schedule has been summarized into the following components: Transmission & Ancillary Services, System Usage, Distribution, Generation Energy Other (Non-NPC), and Generation Energy NPC.

**Q. What is the purpose of including this summary of cost components for the target functionalized revenue requirement?**

A. The summary level for revenue requirement shown in Exhibit PAC/1202, Steward/1-2, summarizes the cost of service results into the target revenue requirement components used in rate design.

The process of unbundling the Company's proposed prices is consistent with the method the Company first implemented in docket UE 116. For each rate schedule, the functionalized costs developed by Mr. Paice are applied to rates as follows: distribution, billing, metering, and customer costs are included in each proposed delivery service schedule's Distribution rates; the Federal Energy Regulatory Commission (FERC) regulated transmission and ancillary services are included in each proposed delivery service schedule's Transmission & Ancillary Services rates; non-net power cost generation costs are included in Schedule 200, Base Supply Service rates; and net power costs are included in Schedule 201, Net Power Costs, Cost-Based Supply Service rates.

**Q. Please explain the System Usage costs shown in exhibit PAC/1202 and how those costs are proposed to be recovered in rates.**

A. In Order No. 12-500, the Commission directed the Company to develop a volumetric rate element for franchise fees that could be avoided by customers taking direct access. The amounts shown as System Usage costs in Exhibit PAC/1202 are a portion of the Oregon Franchise Tax and Oregon Energy

Supplier Assessment from FERC Account 408 in the results of operations.[1] The System Usage costs have been calculated as the portion of the franchise and energy supplier taxes associated with revenues not paid by direct access customers: net power costs and transmission and ancillary services. As discussed later, a separate volumetric rate element has been developed to recover these costs, which will not be paid by direct access customers.

**Q. Have any adjustments been made to the functionalized revenue requirement by rate schedule resulting from the cost of service study sponsored by Mr. Paice?**

A. Yes, consistent with past cases the Company has made one adjustment. The functionalized revenue requirement has been adjusted to remove the proposed changes to net power costs (NPC) collected through Schedule 201. Changes to Schedule 201 are implemented through the Transition Adjustment Mechanism (TAM), which is a separate proceeding from this general rate case, and the Schedule 201 changes will be addressed in that proceeding. The modified cost of service results reflecting this adjustment that removes the NPC increase from the functionalized revenue requirement is shown in Exhibit PAC/1202, Steward/1-2, column (5). This column displays the target functionalized revenue requirement used in the design of rates proposed in this general rate case.

[1]The Oregon Energy Supplier Assessment is a fee paid to the Oregon Department of Energy under ORS 469.421(8). While this treatment for this assessment was not reflected in Order No. 12-500, the Company has included it in the System Usage Charge because it is assessed in the same manner (a percent of revenue) as franchise taxes in FERC Account 408. The Company is therefore proposing parallel treatment.

**Q. Do the Company's proposed rates collect the target functionalized revenues?**

A. Yes. The revenues calculated by multiplying the test period billing determinants by the proposed rates are summarized in column (6) of Exhibit PAC/1202, Steward/1-2. A direct comparison to the target functionalized revenues shown in column (5) of this exhibit shows that the calculated revenues equal the target revenues with the exception of small differences due to the rounding of rates. The detailed calculation of proposed revenues based on billing determinants and proposed rates is shown in Exhibit PAC/1202, Steward/3-12.

**Q. Have you prepared an exhibit showing the estimated effects of the prices proposed in this general rate case?**

A. Yes. Exhibit PAC/1203 shows the estimated effect of the Company's proposed prices. It contains two summary tables: Table 1203-1 shows the effect of the proposed prices by delivery service rate schedule for the proposed net rate increase on January 1, 2014 of $44.8 million; Table 1203-2 shows the effect of the proposed prices by delivery service rate schedule for the revenue requirement change requested in this case of $56.2 million. The expected January 1, 2014 rate increase shown in Table 1203-1 includes the effect following the implementation in early 2013 of Schedule 80, Transmission Investment Adjustment for the Mona-to-Oquirrh transmission project, applied to the 2014 forecast billing determinants. The Transmission Investment Adjustment is currently estimated to be $11.4 million and is expected to become effective during May 2013, as authorized by the Commission in Order No. 12-493. The estimated increase for the Transmission Investment Adjustment, shown in column (6) of Table 1203-1, reduces the net increase that will go into effect on January 1, 2014, from $56.2 million to $44.8 million. These tables show the effect of the price changes on both base revenues and net revenues. Base revenues show the effect before the impacts of any adjustment tariffs. Net revenues include the effect of adjustment tariffs (discussed directly below) and the impact of the $0.2 million RMA rebalancing (discussed later in my testimony).

The adder columns in Tables 1203-1 and 1203-2 show revenues from present adjustment tariff schedules (Schedules 96, 204, and 299). The adder revenue is added to base revenue to calculate net revenue including adjustment schedules. Table 1203-3 shows the calculation of the adjustment revenue included in the adders columns in Tables 1203-1 and 1203-2. Table 1203-4 shows the present and proposed rates for these adjustment schedules. These tables exclude the effects of pass-through adjustment schedules for Low Income Bill Payment Assistance Charge (Schedule 91), the Adjustment Associated with the Pacific Northwest Electric Power Planning and Conservation Act (Schedule 98), the Klamath Dam Removal Surcharges (Schedule 199), the Public Purpose Charge (Schedule 290), and the Energy Conservation Charge (Schedule 297).

Beginning on page 5 of Exhibit PAC/1203 are the monthly billing comparisons for each of the major delivery service rate schedules showing the customer bill impacts of the proposed prices at various levels of usage. The monthly billing comparisons in Exhibit PAC/1203 show the expected rate increases for January 1, 2014, as they include the effect of the estimated Transmission Investment Adjustment in present rates. The monthly billing comparisons also include the effects of all adjustment schedules, including the pass-through adjustment schedules listed above.

**Q. What are the Company's rate spread objectives in this case?**

A. The Company's rate spread objectives in this case are to minimize price impacts on our customers while fairly reflecting cost of service and sending proper signals about increasing costs.

**Q. What is the Company's rate spread proposal in this case?**

A. Based on the cost of service results and in order to achieve the Company's rate spread objectives in this case, Table 1 below summarizes the Company's proposed net percentage price changes for the major rate schedule classes.

**TABLE 1**

| | |
|---|---|
| Residential Schedule 4 | **2.9%** |
| General Service | |
| Schedule 23/723 (0-30kW) | **4.1%** |
| Schedule 28/728 (31-200kW) | **1.7%** |
| Schedule 30/730 (201-999kW) | **5.2%** |
| Large General Service | |
| Schedules 47/747, 48/748 (≥1,000kW) | **6.5%** |
| Agricultural Pumping Service Schedule 41/741 | **3.7%** |
| Lighting Schedules | **6.5%** |
| Overall | **3.7%** |

Under the Company's proposal, the rate change that takes effect January 1, 2014, will result in no customer rate schedule class receiving an increase greater than 6.5 percent. The Company's proposed rate spread strikes a balance between moderating rate impacts on customers, while sending proper price signals about increasing costs and minimizing subsidization across rate schedule classes. As a result, the Company proposes revisions to the RMA to achieve these goals.

**Q. Please describe the Rate Mitigation Adjustment.**

A. The RMA, Schedule 299, is designed to mitigate the impacts of changes in the functionalized revenue requirement on net rates across rate schedules. Net rates are the rates that customers pay once all tariff riders (including the RMA) are taken into account. The RMA is designed to be revenue neutral overall at the time a general rate case price change is implemented, resulting in RMA credits for some rate schedule classes requiring rate mitigation with offsetting RMA charges for others. The RMA was first implemented in docket UE 116 to transition to cost of service rates under SB 1149. The Schedule 299 RMA tariff rider is included in customers' rates for delivery services in order to minimize the effect of the price change allocation across customer classes.

**Q. Besides mitigation of rate changes across rate schedules, what other factors contribute to the adjustment of the RMA in a general rate case?**

A. In each general rate case, the RMA must be rebalanced in order to achieve revenue neutrality so that the revenues from the RMA charges and the RMA credits are in balance. The present Schedule 299 RMA rates were designed to be revenue neutral in the calendar year 2013 test period from the Company's last general rate case, docket UE 246 (2012 Rate Case); however, due to changes in rate schedule loads, present Schedule 299 RMA rates are not projected to produce revenue neutrality in the calendar year 2014 test period of this case. The present RMA rates result in RMA credits that exceed RMA charges by $0.2 million for the 2014 test period loads (see Exhibit PAC/1203, Table 1203-3, Column 5, Row 17). Consistent with prior RMA revisions, the proposed RMA rates have been designed to be revenue neutral for the 2014 test period. As a result of this realignment, the proposed net rate increase in this case is $0.2 million higher than the base revenue requirement increase (Exhibit PAC/1203, Table 1203-1 and Table 1203-2).

**Q. Has the RMA required rebalancing in prior general rate cases?**

A. Yes. For example, in the 2012 Rate Case the RMA required a rebalancing adjustment of $2.8 million.

**Q. What are the present and proposed RMA revenues and rates in this case?**

A. The present and proposed RMA revenues are shown in Exhibit PAC/1203, Table 1203-3, columns (5) and (6). Present and proposed RMA rates are shown in Exhibit PAC/1203, Table 1203-4, columns (5) through (10).

**Q. What is the Company's RMA objective in this case?**

A. The Company's RMA objective in this case is to minimize rate schedule subsidization through the RMA while minimizing impacts on customers. As a result, the Company has limited RMA charges and credits as much as possible. The Company proposes no increase to present RMA credit rates. In addition, the Company proposes to reduce RMA credit rates if the continuation of the present RMA credit rates would result in a percentage increase lower than the overall net percentage increase. As a result, the Company is proposing to reduce the RMA credit to Schedule 41/741, Agricultural Pumping Service by approximately $0.9 million in order to achieve a January 1 net rate impact for Schedule 41/741 equal to the overall net percentage increase of 3.7 percent.

For Large General Service Schedules 47/747 and 48/748, the Company proposes no change to the present RMA credit rates in order to minimize rate impacts to these customers. The proposed January 1 net increase for Schedules 47/747 and 48/748 is 6.5 percent. Eliminating or reducing the RMA credit rates would result in a larger increase for these schedules. With this proposal, Schedule 47/747 and 48/748 will continue to receive the largest RMA credit rates of any rate schedule class, ranging from 0.267 cents per kWh to 0.413 cents per kWh, depending on voltage level, and will produce over $10.1 million of annual credits to these rate schedules. Nonetheless, the Company believes the proposed RMA credits for Schedule 47/747 and 48/748 are reasonable in light of the overall percentage increase proposed for these customers.

Residential Schedule 4 and General Service Schedules 23/723, 28/728, and 30/730 will see a slight reduction in their RMA surcharge rates as a result of the decrease in the credit to Schedule 41/741. Lighting schedules continue to pay an RMA surcharge rate; however, the Company has reduced the RMA rate so the January 1 net increase for this rate class is capped at 6.5 percent, which is consistent with Schedules 48/748 and 47/747.

Overall, the Company believes that these proposals are fair and will minimize rate impacts while reducing subsidization through the RMA.

## RATE DESIGN

**Q. Please generally describe the process for designing rates to collect the proposed revenue requirement.**

A. Proposed rates are designed to collect the target functionalized revenue requirement based on customer billing determinants including number of monthly bills, kilowatts, and kilowatt-hours consumed for the rate case test period. The billing determinants used in this case reflect the forecast test period for the 12 months ending December 2014.

**Q. How are the forecast billing determinants developed?**

A. Forecast test period billing determinants are developed based on the Company's forecast test period bills and energy forecasts along with the historical test period billing determinants.

A three-step process occurs in developing test period billing determinants. First, monthly forecast test period bills and energy by class and by rate schedule are prepared by the Company as described by Ms. Kelcey A. Brown.

Second, a full set of billing determinants, including all rate elements such as kW demand, load size, reactive power quantities and kilowatt-hours by rate block, are retrieved at the customer invoice level from the Company's billing system for the base period—in this case, the 12 months ended June 2012. These historical billing determinants are summarized by class, rate schedule, and voltage level.

Finally, a full set of forecast billing determinants is developed using the historical base period data and the test period forecast. The forecast billing determinants are calculated based upon the ratio of historical bills and energy (temperature normalized) in the base period to the forecast bills and energy provided in the sales forecast.

**Q. Have you provided an exhibit showing proposed rates and the billing determinants used to design rates?**

A. Yes. Exhibit PAC/1202, Steward/3-13, contains historical and forecast billing determinants along with present and proposed base rates.

**Q. Please summarize the rate design changes proposed by the Company.**

A. The basic structure of the Company's current tariffs, broken out into Delivery Service and Supply Service tariffs as first approved in docket UE 116, is proposed to remain in effect. In compliance with Order No. 12-500, the Company has included a new rate element—the System Usage Charge—to unbundle the franchise fee costs that would be avoided by a customer taking direct access. Additionally, the Company is proposing separate treatment for the collection of the Lake Side 2 generation investment.

**Q. Please explain how the System Usage Charge was designed and how it will be applied to customers.**

A. As previously noted, the System Usage Charge is calculated as a per kilowatt-hour rate to unbundle the portion of each rate schedule's allocation of the franchise and energy supplier taxes related to costs that customers taking direct access would not pay to the utility—specifically, net power costs and transmission and ancillary services. Previously, these costs were collected through the distribution rates of each rate schedule for all customers. Consistent with Order No. 12-500, the Company proposes that the System Usage Charge will not be applied to direct access service customers. However, direct access customers will continue to pay the portion of those fees attributed to distribution and non-net power cost generation components. Because the System Usage Charge will not apply to the direct access delivery service schedules, it has not been included in the proposed Direct Access Delivery Service rate schedules in this case. Effective January 1, 2014, when a customer takes service under a direct access delivery service schedule, the customer will pay only the portion of the franchise and energy supplier taxes attributable to direct access delivery service from the Company, as required by Order No. 12-500. The System Usage Charge has been added as a separate section to all cost based delivery service schedules proposed in this filing and included in Exhibit PAC/1201. All cost based delivery service customers will pay the System Usage Charge.

**Q. Please explain the proposed tariffs for residential customers.**

A. Residential customers are served on Delivery Service Schedule 4. For the Basic Charge, the Company proposes to increase the current Basic Charge by $1.00 per month. This results in a proposed Basic Charge of $10.00 per month. This change will better reflect the fixed costs of serving residential customers while, in conjunction with the proposed energy charges, keeping customer impacts in line with the overall rate change for smaller users. Even with this change the Company's Basic Charge will remain at or below the basic/minimum charges of more than half of 24 electric utilities surveyed by the Company in Oregon. The 24 utilities include the major investor-owned and municipally-owned utilities along with people's utility districts and electric cooperatives in Oregon.

For residential customers, as well as for all classes of customers, Schedule 200, Base Supply Service, is proposed to reflect changes in the non-net power cost generation revenue requirement as indicated in Exhibit PAC/1202, Steward/1-2. The Company proposes to keep the same rate blocks and ratio between the rates for each block as in the currently effective rates. The portfolio options (Schedules 210 through 213) do not require changes since they are adders to customers' Schedule 200 rates.

**Q. Please explain the proposed tariffs for general service customers.**

A. The proposed general service tariffs are Schedule 23/723 for small (less than 31 kW) nonresidential general service customers, Schedule 28/728 for general service customers between 31 and 200 kW, and Schedule 30/730 for general service customers over 200 kW but less than 1,000 kW. The Company automatically migrates these customers to the appropriate rate schedule once they meet its applicability criteria. The Company has proposed to modify base delivery and Schedule 200 Base Supply Service prices, at different voltage levels, to collect the target functionalized revenue requirement. For Schedule 30/730 the Company proposes to increase the Schedule 200 demand charges by $0.07 per kW, a percentage increase for that rate approximately equal to the overall base percentage increase for the rate schedule. This increase continues movement toward cost of service while minimizing rate impacts to customers.

**Q. Please explain the proposed tariffs for irrigation customers.**

A. In line with the changes for general service customers, Schedule 41/741, Agricultural Pumping Service rates have been modified to collect the target revenue requirement and to track functionalized costs.

**Q. How has the Company treated Schedule 33 Klamath Basin Irrigation and Drainage Pumping customers in this general rate case?**

A. In accordance with the law and with Order No. 06-172, as clarified in Order No. 06-440, the seven-year rate mitigation transition period for the Klamath Basin irrigation and drainage pumping customers served under the Company's Schedule 33 will conclude on April 16, 2013, before the test year for this case. At that time, these customers will be migrated to standard tariff, Schedule 41, Agricultural Pumping Service. Therefore, for the 2014 test year in this case, the Company has included Schedule 33 customers under standard irrigation tariff Schedule 41 for all rates, revenues and billing determinants.

**Q. Please explain the proposed tariffs for large general service customers.**

A. For Schedules 48/748, Large General Service, the Company has proposed to modify base prices, at different voltage levels, to collect the target functionalized revenue requirement. For partial requirements customers served on Schedule 47/747, most prices are linked to changes in Schedule 48/748 prices. Changes to Schedule 48/748 continue to flow through to Schedule 47/747. The Company proposes to maintain the current Schedule 48/748 rate structure, including an on-peak period demand charge only and the current on-peak/off-peak time of use energy charge differential. As with Schedule 30/730, the Company proposes to increase Schedule 47/747 and 48/748 Schedule 200 demand charges by $0.07 per kW, a percentage increase for that rate approximately equal to the overall base percentage increase for the rate schedule, to better reflect the cost of service while minimizing customer impacts.

**Q. Please explain the proposed tariffs for lighting customers.**

A. For lighting (Schedules 15, 50, 51/55/751, 52/752, 53/753, and 54/754) the proposed revisions are designed to collect the overall functionalized target revenue requirement.

## GENERATION INVESTMENT ADJUSTMENT

**Q. Please explain the proposed rate treatment of the Lake Side 2 generation investment in this general rate case.**

A. As discussed in the testimony of Mr. Gary W. Tawwater, the Company proposes to place in rates the generation investment for the Lake Side 2 generating plant following a prudence review in this case and once the investment becomes used and useful. The in-service date is expected to occur in the second quarter of 2014. Exhibit PAC/1204 presents the proposed rate spread and rates for this adjustment along with an illustrative version of the Generation Investment Adjustment tariff. Following a prudence review in this case, the Company proposes to submit an advice filing in 2014 for approval of the proposed Generation Investment Adjustment tariff no less than 30 days before the in-service date of Lake Side 2.

**Q. How are the proposed generation investment adjustment rates calculated?**

A. The generation investment adjustment costs are allocated to customer classes based on the generation allocation factors from the cost of service study. The proposed tariff rider rates have been designed to collect these costs through energy charges.

**Q. Why has the Company proposed separate treatment of the costs for this generation investment project?**

A. As discussed by Mr. Richard P. Reiten, the Company has proposed this treatment for Lake Side 2 so the prudence of this project may be reviewed in this general rate case and the project may be properly reflected in rates in a timely manner once it becomes used and useful. This is consistent with the treatment of the Mona-to-Oquirrh transmission investment approved by the Commission in Order No. 12-493.

**Q. Are the rates for the Generation Investment Adjustment tariff reflected in the proposed rate spread, rate design and rate impact Exhibits PAC/1202 and PAC/1203?**

A. No. Since this investment is anticipated to become used and useful following the January 1, 2014 effective date of proposed rates in this case, the effects of this proposed adjustment are not included in the rate comparisons or rate impacts in these exhibits.

**Q. What will be the rate change attributable to the Generation Investment Adjustment tariff proposed to become effective in May 2014?**

A. As shown in Exhibit PAC/1204, the annualized effect of the Generation Investment Adjustment tariff is approximately $22.7 million, equal to an increase of approximately 1.8 percent.

**Q. Does this conclude your direct testimony?**

A. Yes.