Docket No. UE 263
Exhibit PAC/1100
Witness: C. Craig Paice

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Direct Testimony of C. Craig Paice

March 2013

DIRECT TESTIMONY OF C. CRAIG PAICE

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

A. My name is C. Craig Paice. My business address is 825 NE Multnomah Street, Suite 2000, Portland, Oregon 97232. I am currently employed as a Regulatory Specialist in the Regulation Department.

QUALIFICATIONS

Q. Please describe your education and professional experience.

A. I received a Bachelor of Science Degree in Business Management from Brigham Young University in 1976. I have also attended various educational, professional, and electric industry seminars during my career with the Company. I have been employed by PacifiCorp since the merger with Utah Power & Light Company in 1989. Beginning in 1978 I was employed by Utah Power & Light Company, holding various positions in the accounting, customer service, and regulatory areas.

Q. What are your current responsibilities?

A. My primary responsibilities are to prepare, present, and explain the results of the Company's cost of service studies to regulators and interested parties in jurisdictions where PacifiCorp provides retail electric service.

PURPOSE OF TESTIMONY

Q. What is the purpose of your testimony?

A. I present the Company's proposed revenue requirement for each of the unbundled service categories, the Company's functionalization procedures, and the Oregon Marginal Cost Study.

UNBUNDLED CLASS REVENUE REQUIREMENTS

Q. Please identify Exhibit PAC/1101 and explain what it shows.

A. Exhibit PAC/1101 shows the Company's proposed revenue requirement for each of the unbundled service categories required by OAR 860-038-0200: Generation (also referred to as Production), Transmission, Distribution, Ancillary Services, Consumer Services—Billing, Consumer Services—Metering, Consumer Services—Other, Retail Services, and Investment in Public Purposes.

No revenue requirement is shown for the Retail Services or Investment in Public Purposes categories. The Company separately accounts for the costs associated with unregulated retail activities and is not seeking regulatory cost recovery for these items. Public purpose revenues are collected under a separate tariff.

Q. How was the revenue requirement determined for each of the unbundled categories?

A. Rate base balances, revenues, and expenses were either assigned or allocated to unbundled categories in accordance with OAR 860-038-0200. Traditional revenue requirement methodology (i.e., recovery of costs plus a return on rate base), was then used to determine a revenue requirement for each category. Rate base balances, revenues and expenses are from PacifiCorp's Oregon Results of Operations Report, as filed by Mr. Gary W. Tawwater. The application of PacifiCorp's proposed rate increase is shown on page 2 of Exhibit PAC/1101.

Q. Please identify Exhibit PAC/1102 and explain what it shows.

A. Exhibit PAC/1102, Tab 1 is the summary page from PacifiCorp's December 2014

Functionalized Oregon Results of Operations Report (Functionalized Oregon Results of Operations Report) and is the basis for the unbundled revenue requirement in Exhibit PAC/1101. It separates the results of operations into the unbundled categories identified above.

Q. Please explain how the rate base balances, revenues and expenses in the Functionalized Oregon Results of Operations Report were apportioned among the unbundled categories.

A. The detail of PacifiCorp's Functionalized Results of Operations Report by Federal Energy Regulatory Commission (FERC) account is found in Exhibit PAC/1102, Tab 2. The functionalization procedures in this case are consistent with those approved in Order No. 01-787 and implemented in Advice No. 01-020. Functional factors employed in the development of these results are provided in Exhibit PAC/1106.

Q. How did PacifiCorp determine the revenue requirement for Ancillary Services?

A. The revenue requirement for Ancillary Services was estimated by applying PacifiCorp's prices for Regulation and Frequency Response Service, Spinning Reserve Service, and Supplemental Reserve Service to the relevant billing determinants of PacifiCorp's total Oregon retail load. This is shown in Exhibit PAC/1103. The costs associated with providing these services are included in the Generation function. The estimated revenue for Ancillary Services is treated as an offsetting revenue credit against the Generation revenue requirement.

Q. Please identify Exhibit PAC/1104.

A. Exhibit PAC/1104 contains a summary from PacifiCorp's State of Oregon December 2014 Marginal Cost Study (Marginal Cost Study). The Marginal Cost Study is described in more detail later in my testimony.

Q. Please identify Exhibit PAC/1105 and explain what it shows.

A. Page 1 of Exhibit PAC/1105 is the derivation of functionalized class revenue requirements and a comparison with current revenues. This exhibit is based on the results of both the Functionalized Oregon Results of Operations Report and the Marginal Cost Study. Present class revenues are shown on line 1 and megawatt-hours (MWh) are shown on line 2. Full long-run marginal costs for each customer class, separated by function, are shown on lines 5 through 11. Lines 15 through 23 show each class' share of total marginal costs for each function as well as each class' share of revenue and MWh. Lines 27 through 36 show the assignment of functional revenue requirement. The total revenue requirement for each unbundled category, as determined earlier is shown in the total column. The total for each function is then allocated to a particular customer class based on that class' share of total marginal cost for that function. For example, the residential class accounts for 42.24 percent of generation marginal costs and is assigned 42.24 percent of the generation revenue requirement. Regulatory and franchise fees are considered part of the distribution function; however, for the purpose of assigning cost responsibility, the fees have been broken out separately. Regulatory and franchise fees have been assigned on the basis of class revenue. Lines 38 through 45 compare the total revenue requirement by class to the present class revenues collected from base rates as shown on line 1.

Q. Please explain what is shown on pages 2 and 3 of Exhibit PAC/1105.

A. Pages 2 and 3 of Exhibit PAC/1105 provides a reconciliation between Operating Revenues and Target Revenue Requirement as shown on page 1 of this exhibit, with those shown in Exhibits PAC/1101 and PAC/1102. Not all customer classes are included in the Marginal Cost Study. Page 2 of Exhibit PAC/1105 accounts for all Oregon test period revenue sources. Page 3 accounts for all revenue sources included in the Target Revenue Requirement.

MARGINAL COST STUDY

Q. Please describe PacifiCorp's Marginal Cost Study that accompanies this filing.

A. The Marginal Cost Study is found in Exhibit PAC/1107. This study shows, by customer class, PacifiCorp's marginal cost of resources required to produce one additional unit of electricity, or to add one additional customer. Exhibit PAC/1107 contains a marginal cost and circuit model procedures narrative, various summary tables, and 15 sections of supporting data.

Q. Is this Marginal Cost Study similar to studies the Company has previously filed?

A. Yes. This study is similar with the cost of service study presented in the Company's 2012 general rate case, docket UE 246 (2012 Rate Case), however it includes two modifications recommended by parties in that proceeding. First, since the Company is subject to Oregon's renewable portfolio standard (RPS) and a percentage of its retail electricity sales must be from qualified renewable resources, it is appropriate for the calculation of marginal generation energy costs to include renewable resource costs. The Company submitted a compliance filing for tariff changes to provide qualified facilities with an option for avoided cost pricing for renewable resources in docket UM 1396. The Marginal Cost Study has been modified to recognize the impact of renewable energy resources on generation energy costs. This revision follows Staff's recommendation in the 2012 Rate Case.

Second, the Company's distribution circuit model has been revised to include commitment and demand costs on the circuit model trunk, branches six and seven, as is done for branches one through five. Previously, trunk costs were considered to be 100 percent demand-related. Trunk costs should be considered both demand and commitment related since these costs are recognized on all other branches of the circuit and because no specific engineering data is available to support the position that circuit model trunk costs are exclusively demand-related. This revision is consistent with recommendations made by Staff of the Commission and Industrial Customers of Northwest Utilities in the 2012 Rate Case. Both revisions in the Marginal Cost Study illustrate reasonable methods of cost derivation.

Q. How are marginal costs calculated?

A. One-year marginal costs include only changes in operating costs while 10-year and 20-year marginal costs also include the cost of expanding facilities. The costs of these added facilities result in long-run costs that are higher than short-run costs. Short-run costs include only one year of generation energy costs and some billing costs. They do not include any demand-related generation, transmission, or distribution costs. A detailed description of marginal cost procedures is included in Exhibit PAC/1107, Tab 1.

Q. Please describe the marginal cost summary tables included in Exhibit PAC/1107, Tab 2.

A. Tables 1 and 2 of Exhibit PAC/1107 summarize the one-year, 10-year and 20-year marginal costs on a mills-per-kWh or dollars-per-customer basis. Table 3 summarizes the unit costs based on the results of the long-run (20-year) marginal cost study. Unit costs are shown for generation, transmission, distribution and various customer service functional categories. Table 3 also includes energy usage, peak demand, and number of customers by customer class for the 12 month period ending June 30, 2014 (Test Period). This information is used to calculate annual long-run marginal costs by class shown on Table 4.

Q. Please explain how generation marginal costs are calculated.

A. Marginal generation costs in this study are based on the Company's currently approved Oregon avoided cost calculations. New resource costs are based on the fixed and variable cost of a combined cycle combustion turbine, which operates as a base load unit. Recognizing that base load generation produces the dual products of capacity and energy, capacity costs are determined using the fixed costs of a simple cycle combustion turbine. Generation energy costs are calculated by combining the remaining fixed and all variable costs of the combined cycle turbine plus renewable wind resource costs. Renewable resource costs included in the marginal cost of service study are based on a Wyoming wind facility (35 percent capacity factor) shown in Table 6.3 of the Company's 2011 integrated resource plan (IRP) which is consistent with the renewable avoided cost compliance filing in docket UM 1396. These costs are weighted according to the Oregon RPS requirements for each year during the long-run marginal cost period. This results in weightings of five percent for 2014, 15 percent for 2015-2019, 20 percent for 2020-2024, and 25 percent for 2025-2032. Non-renewable marginal energy costs are reduced by one minus the renewable weighting percentage, added to the weighted renewable costs, summed and present valued to determine marginal energy costs. Weighting the cost of renewable energy by the Oregon mandatory RPS requirements is a straightforward and easily understood method of recognizing these costs. Marginal generation capacity and energy costs are summarized on Table 5 of Exhibit PAC/1107.

Q. How are transmission costs calculated?

A. Transmission costs are based on a five-year analysis of forecasted expenditures to meet increased load on the transmission system. Expenditures identified as growth-related are used to develop marginal transmission costs. All of these growth-related transmission investments, except bulk power lines, are classified entirely to demand. Bulk power lines are classified both to demand and energy in the same proportions as the long-run marginal costs of generation resources. Marginal transmission costs are summarized on Table 6 of Exhibit PAC/1107.

Q. Please provide a general overview of how marginal distribution costs are determined.

A. Table 7 of Exhibit PAC/1107 provides a unit cost summary by class and load size of marginal distribution costs. Distribution costs are classified into three components: (1) demand-related, shown in dollars per kW/year; (2) commitment-related, shown in dollars per customer/year; and (3) billing-related, shown in dollars per customer/year. Commitment-related distribution costs consist of the costs of transformers, poles and conductor that are not determined by the level of demand customers place on the system. Demand-related distribution costs include additional costs of larger transformers, substations, poles and conductors with sufficient capacity to serve the level of demand a customer class places on the system.

Q. Please describe how the marginal costs of distribution line transformers are calculated.

A. Marginal transformer costs are calculated using a least squares regression analysis of the current installed cost versus size of the Company's commonly installed transformers. Commitment and demand costs are separated by the nature of this statistical technique. The regression provides an intercept term, which represents the commitment costs, and a slope, which represents the demand cost per kW. The regression also identifies the additional costs of a three-phase transformer over a single-phase transformer.

Q. Please describe how the marginal costs of distribution circuits are calculated.

A. Marginal costs of distribution poles and wires are calculated using the Company's

Distribution Circuit Model. The circuit model focuses on several key characteristics that influence distribution cost of service. Among these are customer density, customer size and usage characteristics, and customer location on the circuit. The hypothetical circuit is constructed with seven branches of equal length using the composite line statistics and current cost estimates for Oregon. Customer locations are based on actual customer distances from the substation as determined by the Company's Computer Aided Design Operations (CADOPS) database. The results are segregated into commitment-related and demand-related costs for each customer class. A detailed description of the updated circuit model is also included in the marginal cost procedures in Exhibit PAC/1107, Tab 1.

Q. How are substation marginal costs calculated?

A. Marginal substation costs are determined using the per kW cost of substation additions being considered for a five-year period. The cost per kW is determined by dividing the growth-related distribution substation investment in the capital budget horizon by the related increase in substation capacity. Substation marginal costs are classified entirely to demand and are allocated to customer classes based on the distribution peak load for each class.

Q. What is included in the service drop category?

A. The service drop category includes the marginal cost of service drops with associated operation and maintenance (O&M). Current typical installed costs for service drops are determined for each customer load size.

Q. What is included in the metering category?

A. The metering category includes the marginal cost of metering equipment with associated O&M and meter reading expense. Current typical installed metering costs are determined for each customer load size by analyzing service requirements, such as single or three-phase service and voltage level. Meter O&M is based on historical expenditures.

Q. What is included in the billing and customer service/other categories?

A. This category includes the costs of billing, payment processing and debt recovery, meter reading expense and all the remaining customer accounting and customer service activities. Meter reading expense is based on historical costs and allocated to customer classes based on typical meter reading times. Customer accounting and customer service expense are based on historical expenditures and are assigned to each customer class based on the various resources required to perform billing, collections, and customer service activities for different types of customers.

Q. Does this conclude your direct testimony?

A. Yes.