Application No. 18-04-___
Exhibit PAC/1200
Witness: Robert M. Meredith

BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF CALIFORNIA

PACIFICORP

Direct Testimony of Robert M. Meredith

Cost of Service

April 2018

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ATTACHED EXHIBITS

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

A. My name is Robert M. Meredith. My business address is 825 N.E. Multnomah St, Suite 2000, Portland, Oregon 97232. My present position is Manager, Pricing and Cost of Service.

I. QUALIFICATIONS

Q. Please briefly describe your education and business experience.

A. I graduated magna cum laude from Oregon State University in 2004 with a Bachelor of Science degree in Business Administration and a minor in Economics. In addition to my formal education, I have attended various industry-related seminars. I have worked for PacifiCorp for 13 years in various roles of increasing responsibility in the Customer Service, Regulation, and Integrated Resource Planning departments. I have over seven years of experience preparing cost of service and pricing related analyses for each of the six states that PacifiCorp serves. I assumed my present position in March 2016.

Q. Have you testified in previous regulatory proceedings?

A. Yes. I have previously filed testimony on behalf of PacifiCorp in regulatory proceedings in California, Idaho, Oregon, Utah, Washington, and Wyoming.

II. PURPOSE OF TESTIMONY

Q. What is the purpose of your testimony?

A. I will present the development of PacifiCorp's functionalized class revenue requirement and supporting marginal cost-of-service study for the forecasted 12 months ending December 31, 2019 (Test Period). In this marginal cost-of-service study, I support several modifications that were made to the study relative to PacifiCorp's previous studies. These changes were made to increase the accuracy of the study and to better reflect present circumstances.

III. MARGINAL COST OF SERVICE STUDY

Q. Please explain Exhibit PAC/1201, Table 1.

A. Exhibit PAC/1201, Table 1 shows PacifiCorp's functionalized class revenue requirement results based on the proposed revenue requirement change. Line 1 provides normalized present revenues by function for the Test Period. Line 2 shows the proposed revenues for each of the functionalized service categories: Production (also referred to as Generation), FERC Transmission, State Transmission and Distribution. Line 3 shows the proposed revenue changes by function.

Q. Please describe Exhibit PAC/1201, Table 2.

A. Exhibit PAC/1201, Table 2 corresponds to the summary page from PacifiCorp's Test Period Results of Operations Summary for the state of California supported by Ms. Shelley E. McCoy's testimony (Exhibit PAC/1100). It is the basis for the functionalized revenue requirement in Exhibit PAC/1201, Table 1.

Q. Please describe how functionalization is employed in the Results of Operations.

A. Functionalization is the process of separating expenses and rate base items according to utility function. The production or generation function consists of the costs associated with power generation, including mining and wholesale purchases. The transmission function includes the costs associated with the high voltage system utilized for the bulk transmission of power from the generation source and interconnected utilities to the load centers. The distribution function includes the radial distribution system that connects customers to the transmission system. This includes distribution substations, poles and wires, line transformers, service drops, and meters. Also included in the distribution function are the costs of metering, meter reading, billing, collections, and customer service.

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

A. Traditional revenue requirement methodology, recovery of costs plus a return on rate base, is used to determine state and functionalized category revenue requirement. Costs and rate base assets are from PacifiCorp's Test Period Results of Operations for the state of California supported by Ms. McCoy's testimony. The application of PacifiCorp's proposed rate increase, as shown on Exhibit PAC/1201, Table 1, is consistent with Ms. McCoy's Exhibit PAC/1101. As described in Ms. McCoy's testimony, the revenue requirement shown on Table 1 of Exhibit PAC/1201 excludes costs associated with the Energy Cost Adjustment Clause (ECAC).

Q. Please describe Exhibit PAC/1201, Table 3.

A. Exhibit PAC/1201, Table 3 contains the normalized forecast revenues and functional class revenue requirement for the Test Period. Columns (C)–(G), lines 1–12 provide the functionalized forecast revenue by class. Revenue from the ECAC are excluded. Lines 13–24 are based on the results of both PacifiCorp's Functionalized Results of Operations and Marginal Cost Study. For example, the total generation revenue requirement shown in Column (C), line 24 is based on Column (A), line 2 of Exhibit PAC/1201, Table 1. The total generation revenue is then allocated to the various classes of customers based on the percentages shown in Exhibit PAC/1201, Table 6, Column (B).

Q. Please describe Exhibit PAC/1201, Table 4.

Exhibit PAC/1201, Table 4 reflects the results of Exhibit PAC/1201, Table 3 in cents per kilowatt hour (kWh).

Q. Please identify Exhibit PAC/1201, Tables 5 and 6.

A. Exhibit PAC/1201, Tables 5 and 6 contain summaries from PacifiCorp's State of California 2019 Marginal Cost Study. Lines 32–34 of Exhibit PAC/1201, Table 5 provide full functionalized marginal cost for each customer class, and lines 37–41 show each class's percent contribution of the total functionalized marginal cost. For example, Column (B), line 38 shows that the residential class is responsible for 48.33 percent of the total Generation marginal costs. Exhibit PAC/1201, Table 6 summarizes lines 37–40 of Exhibit PAC/1201, Table 5.

IV. CALIFORNIA MARGINAL COST STUDY

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

A. PacifiCorp's 2019 Marginal Cost Study for the state of California is provided as Confidential Exhibit PAC/1202.[1] 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. One- and 10-year marginal costs are calculated in order to show the range of costs over different time periods. Ten-year marginal costs are the primary tool used in setting retail tariff prices. Confidential Exhibit PAC/1202 contains a table of contents, 10 summary tables, and 15 sections of supporting data.

[1] Although some tables containing confidential data have been redacted, all of the summary tables described in my testimony are included in the public version of this exhibit.

Q. How was this study prepared?

A. The Marginal Cost Study was prepared in a similar manner to the study filed in PacifiCorp's most recent California general rate case (GRC), Application (A.) 09-11-015 (2011 Rate Case) and in prior cases. Generation at full marginal cost is based on 10 years of generation costs, as specified in the settlement agreement between PacifiCorp and Division of Ratepayer Advocates[2], reached in PacifiCorp's 1992 GRC[3] (Settlement Agreement). Also as part of the Settlement Agreement, PacifiCorp agreed not to classify transformer costs as demand-related in subsequent marginal cost studies. Therefore, 100 percent of transformer costs contained in this study continue to be classified as commitment costs. Additionally, poles and conductors continue to be classified entirely to demand and a nominal levelized carrying charge is used as directed in Decision (D.) 93-12-016,[4] which approved the Settlement Agreement.

Q. Does this marginal cost study employ the New Customer Only (NCO) method for determining marginal transformer, meter, and service costs?

A. Yes. Consistent with PacifiCorp's 2011 Rate Case, the company continues to utilize the NCO method for determining marginal transformer, meter, and service costs in this case.

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[2] The Division of Ratepayer Advocates is now known as the Office of Ratepayer Advocates.
[3] *In the Matter of the Application of PacifiCorp for Approval of Rate Increase and of Alternative Form of Regulation*, Application No. A.92-12-006, Decision No. 93-12-016 at Attachment A, 28 (Dec. 3, 1993).
[4] *Id.* At 19.

<u>Marginal Cost Study Changes</u>

Q. Are there any differences between this marginal cost study and the previously filed study?

A. Yes. Several changes were made to PacifiCorp's Marginal Cost Study from the 2011 Rate Case. These include the following:

1. The demand measurement used to determine marginal generation and transmission costs was modified to be based upon both the average of each class' 12 system coincident peaks and each class' loads weighted by PacifiCorp's hourly loss of load probability (LOLP).
2. The marginal cost of complying with California's renewables portfolio standard (RPS) was included in the computation of marginal energy-related generation cost.
3. Distribution peaks were weighted by the load of substations peaking in each month.
4. The marginal cost of transmission and distribution substations were modified to align with the transmission and distribution deferral credits used for demand-side management modeling (T&D deferral credits) in PacifiCorp's 2017 Integrated Resource Plan (IRP).
5. The marginal cost of meter reading was set to zero.
6. The quantity of incremental new customers used for the NCO method is based upon incremental new sites by class instead of the incremental change in customer count. The rate of replacement for line transformers, services, and meters used in the NCO method is based upon one divided by the book life of

those assets.

Marginal Cost Study Changes: Changes to Measurement of Demand

Q. Please describe the change that was made to the class demand used to determine marginal generation and transmission costs.

A. In this filing, PacifiCorp calculated the demand-related marginal generation and transmission costs from the average of 12 monthly PacifiCorp system coincident peaks and customer loads weighted by LOLP. These two measurements of capacity are weighted 50 percent each to determine the weighted system peak for each class. Previously in the 2011 Rate Case, only the average of each class' system coincident peaks were used for the determination of demand-related marginal generation and transmission costs.

Q. Why was this measurement of demand used?

A. LOLP is a measurement of the probability in any given hour that PacifiCorp will have insufficient resources to serve its load. LOLP is commonly used in resource planning to determine the capacity contribution of different resources. PacifiCorp uses LOLP to determine the capacity contribution of variable energy resources such as wind or solar in its IRPs.[5] These capacity contributions also inform the prices that PacifiCorp pays qualifying facilities that are variable energy resources for the capacity value they provide to the system. Applying a LOLP weighting to customer class loads gives greater consideration to those hours when PacifiCorp's system is the most stressed.

While PacifiCorp's current estimates of LOLP, that were developed for the 2017 IRP and were used in this marginal cost of service study, show the greatest

[5] See Appendix N – Wind and Solar Capacity Contribution Study in Vol. II of PacifiCorp's 2017 Integrated Resource Plan available at: http://www.pacificorp.com/es/irp.html.

likelihood of loss of load during the months of June, July, and August, the company must serve its peak requirements during all months of the year. Further, demand-related generation and transmission costs are allocated amongst the customers that PacifiCorp serves in different jurisdictions based upon each jurisdiction's share of load coincident with each of the 12 monthly PacifiCorp system coincident peaks. Using both the 12 monthly coincident system peaks and load weighted by LOLP gives recognition to how costs are allocated to PacifiCorp's customers in California and the need to serve loads throughout the year, while also recognizing those hours that resource planners deem to be significant from a reliability perspective.

Q. Is using LOLP to measure class contribution to peak for generation capacity costs in a marginal cost of service study a new and novel approach?

A. No. Many utilities use LOLP to assign marginal generation capacity cost. For example, Southern California Edison and San Diego Gas and Electric both have allocated generation capacity marginal costs to each hour using LOLP in recent GRCs.[6]

<u>Marginal Cost Study Changes: Marginal Cost of RPS Compliance</u>

Q. How was the marginal cost of complying with California's RPS determined?

A. The marginal cost of California RPS compliance is determined by multiplying PacifiCorp's estimated price for an unbundled renewable energy credit (REC) with the California RPS target percentage for each year.

[6] *See Application of S. Cal. Edison Co. to Establish a Marginal Costs, Allocate Revenues, and Design Rates*, Application No. A.17-06-030, Application at 8 (June 30, 2017); *Application of San Diego Gas & Elec. Co. For Authority to Update Marginal Costs, Cost Allocation and Electric Rate Design*, Application No. A.15-04-012, Testimony of Jeffrey J. Shaughnessy at 9 (Feb. 9, 2016).

Q. Why was the cost of purchasing an unbundled REC used to represent the marginal cost of RPS compliance?

A. The RPS requires utilities to generate or purchase a specific percentage of its energy from renewable sources. A REC is a tradable commodity that represents the environmental attributes of one megawatt-hour of qualifying electricity generated from a renewable resource. PacifiCorp can comply with its RPS by purchasing unbundled RECs. The additional cost of purchasing unbundled RECs is added to the variable avoided energy cost in this marginal cost of service study, because it represents the lowest incremental cost of RPS compliance associated with serving an additional unit of energy.

<u>Marginal Cost Study Changes: Changes to Distribution Peaks</u>

Q. Why are distribution peaks weighted by the load of substations peaking in each month?

A. Peak load is the key cost-driver of substation equipment. In making distribution investment decisions, engineers use peak-loading on individual circuits and substation transformers. For many of its distribution substations, PacifiCorp knows the month and magnitude in megawatts of peak load. Weighting the 12 monthly distribution coincident peaks by the load of substations peaking in each month provides a more accurate representation of how costs are incurred to serve load, since it reflects the seasonality of when substations peak.

<u>Marginal Cost Study Changes: Modifications to Marginal Transmission and Distribution Substation Costs</u>

Q. Please describe the changes made to the calculation of marginal transmission and distribution substation costs.

A. The method of calculating the marginal cost of transmission and distribution substation costs was revised in this study to reflect the methodology used in PacifiCorp's IRPs to estimate a transmission and distribution deferral benefit for demand-side management. For marginal transmission cost, the difference in this calculation is that the cost of projected transmission additions are divided by the capacity that would be added from these builds instead of the peak load growth projected for the investment horizon as was done in PacifiCorp's previous marginal cost studies. Using the actual capacity added from the equipment as the denominator is a more accurate reflection of the marginal cost of adding transmission than load growth, because transmission investment is often lumpy and built to reliably serve existing load and provide capacity for load growth that will be experienced in the future.

For marginal distribution substation cost, the difference in the calculation is that the incremental substation cost is multiplied with a substation utilization factor. The substation utilization factor is calculated by dividing the maximum distribution peak by the installed capacity of existing distribution substations. The distribution peak is expanded by transmission voltage level losses and substation thermal loading. Applying a utilization factor to distribution substation costs reflects the fact that substation capacity additions are typically done in blocks which result in some substations being close to being fully utilized and others operating below peak capacity.

<u>Marginal Cost Study Changes: Meter Reading Costs</u>

Q. Why were marginal meter reading costs set to zero in this filing?

A. Almost all of PacifiCorp's meters in California will be replaced with advanced metering infrastructure (AMI) meters by 2019. With AMI technology there is no marginal cost associated with reading meters. While initially after the rollout of AMI meters a very small handful of meters will be read by phone, the telephony costs associated with these meters are estimated to be negligible.

<u>Marginal Cost Study Changes: NCO Method</u>

Q. Please describe the changes made to the data used in the NCO method.

Previously in the 2011 Rate Case, the number of incremental customers was calculated as the difference between the customer counts of the test period and the previous GRC. In this filing, new customer connections has been determined by counting the new sites by rate schedule between the test period of the previous GRC and base period of the current filing. Using actual new sites instead of incremental customer count better represents how new commitment-related costs are incurred, because incremental customer count reflects a reduction of sites which during the time period became vacant. Vacant or abandoned sites do not negate the incremental costs of serving a new site.

Plant replacements are calculated separately for the three commitment-related facilities—line transformer, service drops, and meters. The computation is the product of the number of average customers in the test period and the replacement rate of the facility. The replacement rate is calculated as one divided by the average life of the facility. For example, there is an estimated 652 customers who would require a line transformer replacement for the residential class, which is calculated by multiplying 35,861 average test period residential customers by one divided by the 55 year average life for line transformers. Previously, PacifiCorp used a generic plant replacement rate of 1.5 percent for line transformers, service drops, and meters.

<u>Marginal Cost Calculation</u>

Q. In the marginal cost-of-service study, how are one-year and 10-year marginal costs calculated?

A. One-year marginal costs include only changes in operating costs, while 10-year marginal costs also include the cost of expanding facilities. The cost of added facilities results in long-run costs, which are higher than short-run costs. Short-run costs include only one year of generation energy costs and some billing costs. Long-run costs include 10 years of generation plus transmission and distribution costs.

Q. Please explain the marginal cost summary tables in Confidential Exhibit PAC/1202.

A. Tables 1 and 2 of Confidential Exhibit PAC/1202 summarize the one- and 10-year marginal costs by customer class and load size group and are shown in mills/kWh. Marginal commitment costs and billing expenses, which are referred to as customer costs, are shown in dollars per customer per month for both the one-year and 10-year time periods.

Confidential Exhibit PAC/1202, Table 3 summarizes the unit costs based on the results of the 10-year marginal cost study. Unit costs are shown for generation, transmission, distribution, and various customer service functional categories. This table also includes energy usage, loads, and number of customers by customer class for the forecast test year and is used to calculate the annual class long-run marginal costs shown on Confidential Exhibit PAC/1202, Table 4.

Q. Please explain how marginal generation costs are calculated.

A. Marginal generation costs in this study are based on PacifiCorp's most recent avoided cost calculations. These new resource costs are based on the fixed and variable costs of a combined cycle combustion turbine (CCCT), which operates as a base load unit. This recognizes that base load generation produces the dual products of capacity and energy. The cost of the CCCT is split into capacity and energy components. The fixed cost of a simple cycle combustion turbine (SCCT) defines the fixed costs of the CCCT that are assigned to capacity. CCCT fixed costs which are in excess of SCCT fixed costs are assigned to energy and are added to the variable costs of the CCCT to determine total avoided energy costs. Capacity and energy costs are brought to their present value, summed, and an annual charge is applied to the total.

As discussed earlier in my testimony, the marginal capacity cost considers both the 12 monthly PacifiCorp system coincident peaks and the hours with LOLP that are used by resource planning. All 12 monthly peaks are considered, since capacity is important each month for meeting peak loads, load following, thermal maintenance, and special sales. The hours of LOLP are considered, because those are the hours of potential greatest stress to PacifiCorp's system. Marginal generation costs are summarized in Confidential Exhibit PAC/1202, Table 5.

Q. How are transmission costs calculated?

A. Transmission costs in this study are based on five years (2016–2020) of transmission investments which can be clearly identified with an increase in capacity. 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 cost of generation resources. Marginal transmission costs are summarized in Confidential Exhibit PAC/1202, Table 6.

Q. Please explain Confidential Exhibit PAC/1202, Table 7.

A. Confidential Exhibit PAC/1202, Table 7 provides a unit cost summary of marginal distribution and billing costs by class and load size. Distribution costs are classified into three components: demand-related, shown in dollars per kilowatt (kW)/year; commitment-related, shown in dollars per customer/year; and billing-related, also shown in dollars per customer/year.

Q. How are distribution line transformer, meter, and service marginal costs calculated?

A. Derivation of marginal transformer, meter, and service costs are illustrated in Confidential Exhibit PAC/1202, Table 8. Calculating costs per customer using the NCO method requires the development of 1) investment costs, 2) hookup and replacement values based on total and incremental new customers, and 3) a present value revenue requirement (PVRR) for California distribution assets.

First, transformer costs are calculated using a least squares regression analysis of the current installed cost versus size of PacifiCorp's commonly installed transformers. The fixed and load-size components are separated by the nature of this statistical technique. The regression provides an intercept term, which represents the fixed component, and a slope, which represents the load size cost per kW. Since PacifiCorp agreed not to classify transformer costs as demand-related in subsequent marginal cost studies,[7] both the fixed and load-size transformer costs have been classified as commitment costs in this study. Service costs include the costs of new service drop investment plus associated operations and maintenance (O&M) expense. Average service drop investments are determined for each customer load size by analyzing service requirements, such as single or three-phase service and voltage level. Service drop O&M is based on the average of 10 years of historical expenditures. Metering costs include the cost of metering equipment with associated O&M. Average meter investments are determined for each customer load size by also analyzing service requirements similar to those for service drops. Meter O&M is based on historical expenditures.

Second, for each customer group, the incremental new customer sites that went into service between 2012 and 2016 was used to develop average new hookups, and a plant replacement percentage based upon the average life of the equipment was applied to December 2019 customer counts to calculate a plant replacement value.

Finally, a current PVRR value for California distribution assets was used to derive the transformer, service, and meter costs for each rate schedule.

[7] *In the Matter of the Application of PacifiCorp for Approval of Rate Increase and of Alternative Form of Regulation*, Application No. A.92-12-006, Decision No. 93-12-016 at Attachment A, 28 (Dec. 3, 1993).

Q. Please describe how the marginal costs of distribution poles and conductor are calculated.

A. The marginal cost of distribution poles and conductor are calculated using PacifiCorp'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 composite line statistics and current cost estimates for PacifiCorp's California service territory. The unit cost of each branch of the circuit is calculated by dividing the total cost of the branch by the branch peak kW (circuit kW peak of all customers located on or served downstream from that branch).

The circuit model complies with the Settlement Agreement,[8] wherein PacifiCorp agreed to classify pole and conductor costs as 100 percent demand-related in subsequent marginal cost studies.

Q. How are substation marginal costs calculated?

A. Marginal substation costs are determined using the per-kW cost of recent and planned substation additions. The cost per kW is determined by dividing growth-related distribution substation investment by the related increase in substation capacity and multiplying by the substation utilization factor. Substation marginal costs are classified entirely to demand and are allocated to customer classes based on the distribution peak load for each class.

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[8] *Id.*

Q. What is included in the customer accounting, service, and information category?

A. This category includes the costs of billing, payment processing, debt recovery, customer accounting, and customer service activities. 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.

VI. CONCLUSION

Q. Please summarize your testimony.

A. PacifiCorp has made several enhancements to its marginal cost of service study in this filing from the 2011 Rate Case. These changes incorporate more detail and accuracy into the calculation of marginal costs and also consider changing conditions that have occurred since the time of the last GRC. I recommend that the Commission approve PacifiCorp's marginal cost of service study.

Q. Does this conclude your direct testimony?

A. Yes.