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I. Introduction and Summary

Q. Please state your names and positions.

A. My name is Robert Macfarlane. I am a senior analyst in Pricing and Tariffs for PGE. I am responsible, along with Mr. Cody, for the development of the marginal cost studies.

My name is Marc Cody. I am an senior analyst in Pricing and Tariffs for PGE. I am also responsible for the development of the marginal cost studies.

Our qualifications are included at the end of this testimony.

Q. What is the purpose of your testimony?

A. Our testimony describes the methodologies and results of PGE's generation, transmission, distribution, customer service, and street lighting marginal cost studies. PGE Exhibit 1301 provides a summary of these marginal costs by component. The summary lists costs by PGE rate schedule for generation capacity and energy, subtransmission, substation, feeder backbone and tapline, transformers, service laterals, meters and customer service costs. Rate schedule changes are discussed in PGE Exhibit 1300.

Q. What is the purpose of the distribution and customer marginal cost studies?

A. The purpose is to calculate the incremental, or marginal unit cost of service for various categories such as distribution substations and feeders, or billing. These unit costs, expressed as costs per customer, costs per kilowatt (kW) of demand, or costs per kilowatt hour (kWh) are then used to allocate the functional revenue requirements as described in PGE Exhibit 1400.

II. Generation Marginal Cost Study

Q. What methodology do you propose in this docket?

A. We propose a long-run generation methodology that explicitly takes into account the cost of marginal generation capacity, long-run marginal energy costs, and renewable energy requirements.

Q. What type of simple cycle combustion turbine (SCCT) did you use to estimate the marginal capacity costs?

A. Consistent with the methodology used to establish prices in UE 294, we use an "F-class" SCCT. This unit has lower capital costs than the LMS 100 and reciprocating engine units described in PGE's 2016 Integrated Resource Plan (IRP).

Q. Please describe the steps used to develop the long-run generation allocation methodology.

A. The generation marginal cost analysis involves the following inputs and steps:

1. Determine both a long-run marginal energy cost and a long-run marginal capacity cost by first defining the marginal long-run generation resource as a combined cycle combustion turbine (CCCT) used to provide both energy and capacity.
2. From this analysis, separately estimate the capacity and energy components as follows:
    a) Estimate the marginal cost of future capacity as the fixed cost of an "F-class" SCCT.

b) Use these SCCT fixed costs as the portion of the CCCT fixed cost that is assigned to capacity with the remaining CCCT fixed costs assigned to energy.

c) To the SCCT capacity costs add 17% reserve requirements consistent with PGE's 2016 IRP.

3. Finally, express the capacity and energy values in real levelized terms.

Q. What are the sources of the overnight capital costs for the resources used in the model?

A. PGE's 2016 IRP is the source of the overnight capital costs used in the analysis.

Q. Please describe how you determined the proportion of marginal energy costs attributable to the CCCT and the generic wind farm.

A. We weighted the marginal energy cost by the Renewable Portfolio Standard (RPS) target percentages for each year. For example, if the RPS target is 20% in a given year, the weighting is 20% wind and 80% thermal. The weightings reflect the revised RPS targets included in SB 1547.

Q. What is the source of your long-term gas price forecast?

A. We used the Wood Mackenzie long-term gas price forecast dated November 2016 for the Sumas and AECO hubs, blended with near term forward curves. We equally weighted the projected burnertip prices from these two hubs.

Q. Did you include the projected costs of carbon dioxide compliance in your analysis?

A. No. On both the national and state level, no carbon tax exists. Any potential future carbon tax is uncertain. The exclusion of carbon tax from this analysis is consistent with the treatment of carbon tax for purposes of PGE's avoided cost calculations used in Schedule 201.

Q. Did you include production tax credits (PTC) in your analysis?

A. Yes. The PTC is included at its full level, as available for a resource that commences construction in 2016 for a 2018 online date. This assumption is consistent with the test period for this proceeding.

Q. What is the fully allocated cost of the wind farm?

A. The cost of the generic wind plant exclusive of wheeling is estimated at $40.88/MWh in real levelized 2018 dollars.

Q. How did you estimate each rate schedule's long-run marginal cost of energy?

A. We multiply each schedule's monthly on-peak and off-peak load forecast by the corresponding monthly on-peak and off-peak long-term energy value.

Q. How do you shape the annual long-run marginal cost of energy into monthly on-peak and off-peak values?

A. We shape the annual long-run marginal energy cost into monthly on-peak and off-peak values based on the monthly on-peak and off-peak Mid-Columbia forward prices used in PGE's production cost model, MONET.

Q. Did you include an estimate of load following costs in the marginal cost of generation analysis as specified in the UE 294 Second Partial Stipulation?

A. Yes.

Q. What is your estimate of PGE's cost-of-service (COS) load following capacity requirements and how do you calculate this estimate?

A. Based on 2014 15-minute interval load research data reconciled to balancing authority loads, a load following requirement of about 240 megawatts (MWs) is estimated for COS customers. This amount of load following requirement is calculated by summing the individual COS rate schedules' 15-minute interval loads and then calculating the maximum and minimum values of these summed loads within each hourly interval. The difference between these maximum and minimum values within each hourly interval at the 99th percentile provides the 240 MW figure.

Q. How do you estimate the marginal load following costs of the 240 MW?

A. We multiply the 240 MW load following requirement by the difference in the unit marginal capacity costs of the "basic" capacity generator contained in PGE Exhibit 1301 and a rapid start LMS 100 capacity generator. The load following amount of 240 MW times the real levelized unit capacity cost difference of approximately $52/kW yields approximately $12.4 million in load following marginal costs. PGE Exhibit 1301 contains a summary of this calculation.

Q. How do you allocate the load following requirements to the individual rate schedules?

A. Each rate schedules' allocation of load following requirements is calculated in the following manner:

1) For each rate schedule calculate the difference in loads from each 15-minute interval to the next 15-minute interval.
2) For each 15-minute interval, determine if the change in each rate schedule's load is either consistent with or contrary to the sum of the rate schedules' interval changes.

3) If the rate schedule's change in load is in the same direction as the sum of the COS load changes, record the change as a positive amount. If the rate schedule's change in load is in the opposite direction of the sum of the COS interval load changes, record the amount of change as a negative number.
4) Sum the positive and negative interval entries for each rate schedule and calculate the load following percentage responsibility for each rate schedule as a percentage of the total sum of changes in COS interval loads.
5) Apply these load following percentages to the marginal cost of providing load following capacity described above.

III. Transmission Marginal Cost Study

Q. Have you performed a transmission unit marginal costs analysis for this docket?

A. Yes. Based on the two transmission projects contained in PGE Exhibit 1302 we calculate a unit marginal cost of $86.31/kW.

Q. Why have you not performed traditional marginal unit costs analyses for transmission in past dockets?

A. Generally because of its limited transmission system, PGE has not had a large amount of transmission investment. It has been more expeditious to directly allocate the relatively small transmission revenue requirement.

Q. Do the two transmission projects discussed in PGE Exhibit 1302 provide sufficient investment to perform a traditional unit marginal costs analysis?

A. Yes. The two transmission projects identified in PGE Exhibit 1302 provide sufficient investment to justify a traditional unit marginal cost analysis. Column (A) in PGE Exhibit 1301, page 3, contains the result of such an analysis.

Q. Is PGE a transmission-dependent utility?

A. Yes. PGE is a transmission-dependent utility that purchases about 3,700 MW of transmission from BPA in order to integrate its generation and purchased power. PGE operates a limited transmission system comprised of approximately 268 pole miles of 500 kV lines and 270 pole miles of 230 kV lines, some of which is functionalized to generation. At the 230 kV level, the system ties into seven BPA bulk power substations around the Portland area. PGE also has ties into three BPA bulk power substations in the Salem area. The primary function of the 230 kV system that is functionalized to transmission is to provide an interface to the main grid for load service.

Q. What drives additions to PGE's existing transmission system?

A. As specified in PGE Exhibit 1302[1], PGE's transmission planners evaluate whether additions to PGE's existing transmission system are needed to meet NERC and WECC reliability standards for serving customers on the basis of 1-in-3 <u>peak</u> load conditions during the summer and winter seasons for both the near term and the long-term[2]. The winter period is defined as November 1st through March 31st, and the summer is defined as June 1st through October 31st, therefore ten months in all. Because the transmission planners use 10 months of peak loads when evaluating reliability, we extend the peak load criteria slightly to 12 months when calculating unit marginal costs. A twelve month criteria, or 12 coincident peak (12CP) is also consistent with how the Federal Energy Regulatory Commission determines PGE's Open Access Transmission Tariff prices.

Q. Has the Commission previously evaluated a PGE proposal to calculate marginal unit costs based on peak loads?

A. Yes. In UM 827, a generic marginal cost docket, the Commission evaluated PGE's calculation of unit marginal costs based on peak loads. The Commission stated the following in Order 98-374:

> We are satisfied with the transmission marginal cost analyses presented by the utilities. As PGE points out, the facilities design approach is not appropriate for calculating transmission marginal costs. Transmission planners must anticipate constant variation in peak loads. The facilities design approach is more appropriate for less dynamic functions of the system.

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[1] Portland General Electric Company's Near Term Local Transmission Plan For the 2016-2017 Planning Cycle.
[2] Ibid, page 6.

IV. Distribution Marginal Cost Study

Q. Which marginal distribution costs do you calculate?

A. We calculate marginal distribution costs (separately) for subtransmission, substations, distribution feeders (backbone facilities and local facilities), line transformers (including services), and meters.

Q. How do you calculate the marginal unit costs of subtransmission and substations?

A. We calculate subtransmission unit costs by first summing growth-related capital expenditures over the five-year period 2017-2021. We then annualize these capital expenditures and divide by the growth in system non-coincident peak (NCP). Customers served at subtransmission voltage are excluded from this calculation because they supply their own substation. We calculate substation marginal costs using a recent engineering estimate of the cost to construct a substation. Then we divide the cost by the substation transformer capacity in kW, and annualize the cost per kW. Columns (B) and (C) in PGE Exhibit 1301, page 3 summarize subtransmission and substation costs.

Q. How do you calculate the marginal unit feeder costs?

A. We estimate distribution feeder unit costs in the following manner:

1. Perform an analysis that places customers by class on the distribution feeder from which they are currently served.
2. Eliminate any distribution feeders from which we cannot obtain customer information, and which do not conform to "typical" standards. Examples of these "non-typical" feeders are feeders serving customers at 4 kilovolt (kV), and feeders that serve downtown core areas.

3. Perform an inventory of the wire types and sizes for each feeder. Standardize these wire types and sizes to current specifications and then calculate the cost of rebuilding these feeders in today's dollars.
4. Segregate the wire types and sizes into mainline feeders and taplines. Mainline feeders are typically capable of carrying larger loads and are generally closer to the substations from which they originate. Taplines are typically capable of carrying smaller loads and can be remote from substations.
5. For each feeder, allocate the mainline cost responsibility of each customer class based on the customer class's proportionate contribution to NCP. Calculate a unit cost per kW by totaling the feeder cost responsibilities and dividing by the sum of each class's NCP.
6. For each feeder, allocate the tapline cost responsibility of each customer class based on its proportionate design demand (estimated peak at the line transformer). Calculate a unit cost per kW for both poly and single phase customers by totaling the feeder cost responsibilities and dividing by the sum of each schedule's design demand.
7. Annualize the mainline and tapline unit costs by applying an economic carrying charge.
8. Separately estimate the unit costs of customers greater than 4 MW who are typically on dedicated distribution feeders. Calculate these marginal unit costs (per customer) as the average distance between the substation and the customer-owned facilities. Finally, apply the annual carrying charge to annualize the cost per customer.

9. Separately estimate the per-customer costs of customers served at subtransmission voltage. This is done by first calculating the average distance from the point at which subtransmission voltage customers connect into the subtransmission system from their substation. Then we multiply this average distance by the current cost per wire mile and annualize the costs.

Columns (D) and (E) on page 3 of PGE Exhibit 1301 summarize feeder mainline and tapline costs.

Q. Why do you propose to calculate the marginal costs of feeders on the basis of class size rather than by rate schedule?

A. We propose this because past marginal feeder costs analyses have resulted in extremely high unit marginal costs for the irrigation Schedules 47 and 49 due to their preponderant location on remote feeders within PGE's service territory. This cost result for the irrigation schedules seems to be due to geographical distinction rather than due to economies of scale. Because PGE does not price by geographical area, we propose the class size distinction when calculating unit marginal feeder costs. For all other marginal cost categories, we separately measure the unit marginal costs of the irrigation schedules.

Q. Please describe any other considerations in calculating unit feeder costs.

A. Currently, many municipalities require undergrounding of taplines within subdivisions and commercial areas. Therefore, we used the current cost of underground facilities exclusively in our marginal feeder tapline cost calculations.

Q. How do you calculate marginal transformer and service costs?

A. We calculate each schedule's marginal transformer and service costs by estimating the cost of providing the average customer within specific load sizes with a service lateral and a line transformer (secondary delivery voltage only). For smaller customers such as those on Schedules 7 and 32, we estimate the average number of customers on a transformer in order to appropriately calculate the per customer share of transformer costs. Column (F) in PGE Exhibit 1301 summarizes transformer and service costs.

Because primary and subtransmission voltage customers supply their own transformer and service laterals, the marginal cost for these customers is zero.

Q. Please describe how you calculate the marginal costs of meters.

A. We calculate marginal meter costs as the weighted installed cost of an Advanced Metering Infrastructure (AMI) meter for each rate schedule or load size, and then apply an annual carrying charge. Column (G) in PGE Exhibit 1301, summarizes meter costs.

Q. How do you allocate distribution operations and maintenance (O&M) to each distribution category and ultimately to each rate schedule?

A. We allocate test-period distribution O&M by distribution category to the rate schedules in proportion to each schedule's respective usage and per unit marginal capital cost. All of the distribution costs by functional category on page 3 of PGE Exhibit 1301, Summary of Distribution and Customer Marginal Cost Studies, are inclusive of test-period distribution O&M.

Q. The UE 294 Second Partial Stipulation required PGE to evaluate the maintenenace costs of secondary voltage conductors and the applicability of those costs to specific rate schedules and delivery voltages. Has PGE met this requirement?

A. Yes. In consultation with field personnel, we reviewed construction estimates for underground secondary voltage conductors and service laterals. Recent marginal cost studies have assumed that pad-mounted transformers that serve multiple customers from a single transformer are configured with underground service laterals that radiate outward from the transformer, similar to spokes on a wheel. This type of configuration does not require any secondary service conductors.

PGE's current underground standards have evolved such that transformers serving multiple residential customers now incorporate secondary voltage conductors that extend to connection points for multiple service laterals.

Q. Have you incorporated this type of configuration into the current marginal cost of service study?

A. Yes, this type of configuration is incorporated into the marginal transformer and service costs for Schedule 7 residential customers.

Q. Please explain how this impacts the maintenance cost of secondary conductors.

A. PGE allocates its projected test period service and transformer maintenance costs on the basis of each schedule's marginal costs; hence changes in the Schedule 7 service and transformer marginal capital costs resulting from the incorporation of secondary conductors will result in changes in how test period service and transformer maintenance costs are allocated to the rate schedules. All else equal, the inclusion of secondary conductors for residential customers service and transformer costs will result in higher allocated test period maintenance costs to residential customers.

V. Customer Service Marginal Cost Study

Q. What is the purpose of the customer service marginal cost study?

A. The purpose is to calculate the incremental cost of customer service for each rate schedule. PGE incurs costs in managing its relationship with customers, including handling customer communications, measuring usage, maintaining records, and billing. As such, customer service costs increase as the number of customers PGE serves increases. Column (H) on page 3 of PGE Exhibit 1301, summarizes marginal customer costs.

Q. Does PGE use the forecasted test year expenses in the customer marginal cost study?

A. Yes. PGE uses forecasted costs for the 2018 test period and 2016 actual costs to develop the 2018 test year customer marginal costs (CMC). These costs are found in FERC Accounts 902, 903, 905, 908, and 909. The 2018 forecasted costs are also referred to as budget amounts in this testimony.

Q. Is the study's methodology the same as in PGE's last rate case – UE 294?

A. Yes, the methodology is the same. As in UE 294, the costs are allocated by PGE accounts directly on the basis of cost causation. A few accounts are allocated based on a sub-allocation of the other account costs. After the costs are spread across rate schedules, the final result is marginal costs for each rate schedule by each of the three functionalized categories: metering, billing, and other services.

Examples of Customer Marginal Cost Calculations

Q. Please provide an example of how you calculate metering marginal costs.

A. The 2018 forecasted budget amount for FERC account 902, Field Collection Department, is allocated based on manual meter reads and a weighted percentage of customers (less unmetered lighting and signals).

Q. Please provide examples of how you calculate billing marginal costs.

A. Examples include:

- The costs for Retail Receivables and Field Collections are allocated based on percentage of adjusted write-offs by rate schedule.
- Customer Information System billing costs are allocated by the number of customers, except streetlights and traffic signals.
- The costs for Printing and Automated Mail Services are allocated based on the number of paper bills delivered.
- Network Data Operation costs are allocated based on the number of customers with meters, which excludes unmetered lighting and traffic signals.

Q. Please provide examples of how you calculate other consumer service marginal costs.

A. Examples include:

- The budget amount associated with the Customer Contact Operations is allocated by the number of customers on rate schedules using up to 200 kW.
- The budget amount for the Direct Access Operations Department is allocated by the number of customers participating in the direct access program.
- The budget amount for the Special Attention Operations Department is allocated based on the number of residential customers.

- The Solar Payment Option and Net Metering Operations budget amounts are allocated by the number of customers participating in the programs.

VI. Area and Streetlights

Q. Please describe how you price Area Lights and Streetlights.

A. We price the investment portion (poles and luminaires) of providing lighting service using a real levelized annual revenue requirement.

Q. Please describe how you calculate the amount of outdoor lighting maintenance.

A. Similar to UE 294, we propose to base the test period lighting maintenance amount on the incurred maintenance amounts during PGE's most recent complete 5-year relamping cycle (2005-2009), before conversion to LED area and streetlights commenced. More specifically, we express the historical maintenance amounts on a per-light basis, and then escalate this per-light maintenance figure for inflation. A further reduction is made for Light-Emitting Diode (LED) street and area lights since (1) their maintenance is significantly less than other lights, and (2) the years used in the most recent 5-year re-lamping cycle do not include LEDs. Following this, we allocate maintenance to each type of luminaire based on the marginal cost of maintenance study.

Q. Do you provide a summary exhibit of the proposed pole and luminaire prices?

A. Yes. This summary is provided in PGE Exhibit 1405.

VII. Qualifications

Q. Mr. Cody, please state your educational background and qualifications.

A. I received a Bachelor of Arts degree and a Master of Science degree from Portland State University. Both degrees were in Economics. The Master of Science degree has a concentration in econometrics and industrial organization.

Since joining PGE in 1996, I have worked as an analyst in the Rates and Regulatory Affairs Department. My duties at PGE have focused on cost of capital estimation, marginal cost of service, rate spread and rate design.

Q. Mr. Macfarlane, please state your educational background and experience.

A. I received a Bachelor of Arts business degree from Portland State University with a focus in Finance. Since joining PGE in 2008, I have worked as an analyst in the Rates and Regulatory Affairs Department. My duties at PGE have included pricing, revenue requirement, Public Utility Regulatory Policies Act avoided costs, and regulatory issues. From 2004 to 2008, I was a consultant with Bates Private Capital in Lake Oswego, OR, where I developed, prepared, and reviewed financial analyses used in securities litigation.

Q. Does this conclude your testimony?

A. Yes.

List of Exhibits

PGE Exhibit	Description
1301	Marginal Cost Study
1302	PGE’s Draft Near Term Local Transmission Plan