

Table of Contents

I. Introduction and Summary 1

II. Marginal Cost of Service Study and Ratespread..... 4

III. Rate Schedule Design..... 17

IV. Other Rate Schedule Changes 34

V. Qualifications..... 37

List of Exhibits 38

I. Introduction and Summary

1 **Q. Please state your names and positions.**

2 A. My name is Doug Kuns. I am the Manager of the Pricing and Tariffs Department within the
3 Rates and Regulatory Affairs Department. My qualifications are described in Section V.

4 My name is Marc Cody. I am a Senior Analyst in the Pricing and Tariffs Department.
5 My qualifications are described in Section V.

6 **Q. What is the purpose of your testimony?**

7 A. This testimony and accompanying exhibits demonstrate how our proposed E-18 Tariff
8 changes recover PGE's 2011 revenue requirement in a way that achieves just and reasonable
9 prices for all our customers. In addition to estimating the overall effect on customer bills,
10 this testimony also describes the Marginal Cost Study, the revenue requirement allocation
11 process, and the rate design.

12 **Q. Has PGE been working with stakeholders regarding marginal cost and ratespread
13 issues since UE 197?**

14 A. Yes. As a result of a stipulation in UE 197, the Commission opened a docket (UM 1415) to
15 address these issues. Workshops have been held and PGE has actively engaged in these
16 workshops.

17 **Q. Do the Marginal Cost Study and the revenue allocations incorporate the principles you
18 outlined during the UM 1415 workshops?**

19 A. Yes. We propose to allocate the functional revenue requirements in the same manner as we
20 outlined during the final UM 1415 workshop of January 8, 2010.

21 **Q. Please summarize the projected Cost of Service rate impacts resulting from the
22 proposed allocations.**

1 A. Table 1 below summarizes the base rate impacts of our proposals for the major rate
2 schedules.

Table 1
Estimated Cost of Service Rate Impacts

	Estimated Rate Change (%) (base rates)
Schedule 7 Residential	8.8%
Schedule 32 Small Nonresidential	8.2%
Schedule 83 31-200 kW	9.3%
Schedule 85 201-1,000 kW	5.8%
Schedule 89 Over 1,000 kW	2.2%
COS Overall	7.3%

3 **Q. Please summarize the methodological changes in marginal cost estimation, ratespread,**
4 **and rate design you have made from the methods used in UE 197.**

- 5 A. The key changes we propose are listed below (and explained in our testimony):
- 6 • Allocate the generation revenue requirement based on long-run marginal costs
7 rather than the short-run methodology employed in previous dockets.
 - 8 • Evaluate and modify the allocation of customer costs that comprise the functional
9 Metering, Billing, and Other Consumer categories. This includes a separate
10 allocation of uncollectible expense to the individual rate schedules.
 - 11 • Create a new rate schedule, Schedule 85, for customers between 201 and 1,000
12 kW facility capacity.
 - 13 • Change the Schedule 7 Residential Service blocking from two blocks with a
14 breakpoint of 250 kWh monthly to three blocks with breakpoints at 500 and 1,000
15 kWh monthly. We also propose a slightly more steeply inclined block rate
16 structure.
 - 17 • Propose various rate design changes that are discussed further in the appropriate
18 section of testimony.

- 1 • Create new schedules and change existing ones. Most of the changes to existing
2 schedules are to accommodate the creation of Schedule 85 and are housekeeping
3 in nature.

4 **Q. Do you propose new supplemental schedules in this filing?**

- 5 A. Yes. We introduce a new Schedule 145 that proposes to incorporate potential changes in
6 end-of-life assumptions related to the Boardman coal plant. We also propose Schedule 141
7 that adjusts annually the revenue requirement associated with pension expense and financing
8 costs related to cash contributions to the pension fund. If approved, both Schedules 145 and
9 141 start with zero prices. We further discuss these schedules later in testimony.

10 **Q. Do you propose changes to existing supplemental schedules or to Schedule 300?**

- 11 A. Yes. We propose to set Schedule 111 Advanced Metering Infrastructure and Schedule 121
12 Selective Water Withdrawal Adjustment prices to zero effective January 1, 2011, consistent
13 with the provisions of the schedules.

14 We propose some language changes to Schedule 123, the Sales Normalization
15 Adjustment. We also propose some language changes to Schedule 126 consistent with the
16 testimony contained in PGE Exhibit 200. Additionally, we propose a language change to
17 Schedule 125 to accommodate a modeling change to thermal plant variable O&M that is
18 discussed in PGE Exhibit 400.

19 Finally, we also propose to increase the Schedule 300 charges for Standard and
20 Enhanced Temporary Service. The Pricing Work Papers contain the basis for the
21 Temporary Service price changes.

II. Marginal Cost of Service Study and Ratespread

1 **Q. Briefly describe the purpose of a Marginal Cost of Service Study.**

2 A. Since the mid-1970s, Oregon utilities have developed marginal cost studies for a number of
3 purposes. In this case, PGE uses its Marginal Cost of Service Study to guide the allocation
4 of the generation, distribution, and customer service (separately, Metering, Billing, and
5 Other Consumer Service) functional revenue requirements in the rate spread process. The
6 results of the distribution and customer service portions of this study are summarized in
7 Table 8 of PGE Exhibit 1505. The generation portion is summarized in PGE Exhibit 1504.

8 **Q. What other functional revenue requirement categories do you allocate besides those
9 mentioned above?**

10 A. Because the Ancillary Services revenue requirement is split out from generation, we allocate
11 it in the same manner as we do generation. We also allocate the transmission revenue
12 requirement in accordance with the generation allocation. These two functional categories
13 combined with the five categories above complete the seven functional categories specified
14 in Senate Bill 1149 enacted in 2002.

15 **Q. Why do you allocate transmission revenue requirements in the same manner as you do
16 generation?**

17 A. Generally, we have previously allocated transmission revenue requirements on a peak load
18 basis. The 1992 NARUC Cost Allocation Manual lends support to this on page 128: “For
19 purposes of a marginal cost study, investment in the transmission system is generally
20 assumed to be driven by increments in system peak load.”

21 However, in this docket, we allocate transmission revenue requirements consistent with
22 long-term generation marginal costs. We do so because PGE’s 2009 Integrated Resource

1 Plan (IRP) proposes two large transmission projects, Cascade Crossing and South of Allston
2 that interconnect existing PGE generation resources as well as new gas and wind resources.

3 **Q. Please describe the analysis you performed regarding the allocation of these two**
4 **transmission projects.**

5 A. We first designated the South of Allston project entirely as capacity because it will integrate
6 a new peaking resource of up to 200 MW as well as integrate the Beaver capacity of 181
7 MW that is not integrated from the Port Westward to Trojan line. The Cascade Crossing
8 project will integrate Boardman, Coyote, a new 450 MW combined cycle baseload gas
9 plant, and approximately 600 MW of new wind resources. Consistent with our generation
10 marginal cost study, we designate all but the wind resources as 31% capacity, 69% energy.
11 We designate the wind resources as 100% energy. We then allocate the nameplate capacity
12 of all the existing and proposed resources in the manner described above. The result for the
13 two transmission projects is an allocation of approximately 35% to capacity and 65% to
14 energy.

15 **Q. Did you allocate the two projects on the basis of capital expenditures?**

16 A. Yes. We used the same capacity/energy designations for each generation resource above to
17 allocate the estimated \$45 million South of Allston project costs and the estimated \$823
18 million (both projects in 2009 dollars) Cascade Crossing project costs. The result of this
19 allocation was approximately 24% to capacity and 76% to energy. The Pricing work papers
20 contain the two aforementioned analyses.

21 **Q. How do these two analyses support the transmission allocation based on generation?**

22 A. We used the generation cost allocation for transmission revenue requirements because the
23 simple average of these two analyses approximates the test period generation cost allocation

1 of 31% capacity/69% energy. The details of the two analyses are contained in the Pricing
2 work papers.

3 **Q. Do you allocate other cost categories to the individual rate schedules?**

4 A. Yes. We allocate franchise fees and OPUC fees on a current revenue basis and Trojan
5 decommissioning on a busbar energy basis. We allocate Schedule 129 Long-Term
6 Transition Adjustment to Schedule 85 and 89 customers on an energy basis, and finally, we
7 allocate uncollectible expense based on historical incidence for the years 2006-2008. This
8 latter category was previously not specifically allocated, but was treated as a revenue
9 sensitive cost, and was therefore implicitly allocated to schedules on a revenue basis. All
10 allocations are presented in PGE Exhibit 1504.

11 **Q. Do you propose any form of rate mitigation or other deviation from using marginal
12 cost to spread the revenue requirements?**

13 A. No, however, we employ the Customer Impact Offset (CIO) after spreading the revenue
14 requirements in order to temper the rate impacts to certain schedules. Specifically, we limit
15 the rate increase to two times the average increase for Schedules 38, 47, 49, and 93. We
16 further limit the subsidy to no more than 9.5 cents/kWh. For our major cost of service rate
17 schedules (7, 32, 83, 85, and 89) we limit the increase to 1.25 times the average increase.
18 Additionally, before calculating the increase limit discussed above, we set a floor such that
19 no rate schedule receives a decrease. When allocating the CIO we do not propose any
20 surcharges for schedules 7, 32, and 83 because for these schedules we propose increases that
21 are above the average increase. We further discuss the CIO later in this testimony.

22 **Q. Could you please provide a brief history of how PGE has previously estimated its
23 marginal cost of generation?**

1 A. Prior to this docket, PGE has used the same short-run marginal cost methodology since
2 UM 827 (1997). PGE stated at that time the following:

3 PGE’s Avoided Cost Study, which was approved by the Commission and became
4 effective on December 18, 1996, serves as the foundation for determining
5 marginal generation costs. In this study, the combined effect of a significant
6 reserve margin in the 11-state WSCC and an increasingly vibrant market for
7 electricity was observed to drive the cost of short-term firm power below the cost
8 of a new, long-term generating resource and below the fully allocated cost of
9 existing resources. We expect this trend, and its effect on short-term prices, to
10 remain for the foreseeable future. Moreover, this trend has significantly reduced
11 the cost of capacity, which is reflected now primarily through the differential
12 between on-peak and off-peak energy prices.

13 **Q. Please continue.**

14 A. When we filed UE 115 in 2000 we used the same short-run methodology. At that time we
15 did not contemplate new generation resources, in particular given that the UE 115 docket
16 was largely about restructuring to accommodate direct access and portfolio options
17 consistent with the requirements contained in Senate Bill 1149. At that time no one objected
18 to the short-run marginal cost approach and we subsequently settled on a generation
19 allocation methodology. This methodology specified historical resource shares of existing
20 assets accompanied by allocations of BPA Subscription Power as part of a resource stacking
21 methodology.

22 In UE 180, which we filed in March of 2006, we proposed once again the same
23 marginal cost methodology, thereby eliminating the historical generation allocations
24 stipulated to in UE 115. In UE 180, the methodology was opposed solely by ICNU in its
25 direct testimony. Prior to PGE filing its rebuttal testimony, parties settled ratespread and
26 rate design issues. The outcome of this settlement was the adoption of the PGE proposed
27 marginal cost and generation allocation methodology.

28 **Q. Please describe the positions of parties in UE 197.**

1 A. In UE 197, PGE proposed the same short-run marginal cost of generation methodology as in
2 the prior dockets. ICNU raised issues with this methodology relating to the lack of
3 consideration of capacity costs and reliability planning. Staff in Staff Exhibit 600 stated that
4 they recommend adoption of PGE’s marginal cost study because it provides reasonable
5 results. However, on page 6, line 18 to page 7, line 2 Staff stated the following: “regarding
6 production marginal costs it seems reasonable to use potential new electrical generating
7 plants as the basis for capacity and energy costs instead of relying exclusively on wholesale
8 market energy prices.” Staff in Staff Exhibit 1200 then stated a preference to use the
9 generation marginal cost as filed by PGE in its direct testimony. CUB in their surrebuttal
10 testimony supported using the short-run methodology proposed by PGE in its direct
11 testimony.

12 **Q. What methodology do you propose in this docket?**

13 A. We propose a long-run generation methodology that explicitly takes into account the cost of
14 marginal generation capacity and long-run marginal energy costs. This marginal cost
15 methodology is consistent with our IRP that identifies a need for capacity resources for both
16 the winter and summer periods. This methodology is similar to the long-run methodology
17 we proposed as an alternative in our UE 197 Rebuttal testimony. It is also the methodology
18 we proposed during the UM 1415 workshops.

19 **Q. Please describe the steps you used to develop the long-run generation allocation**
20 **methodology.**

21 A. The generation marginal cost analysis involves the following inputs and steps:
22 1. Determine both a long-run marginal energy cost and a long-run marginal
23 capacity cost by first defining the marginal long-run generation resource as
24 a combined cycle combustion turbine (CCCT) used for baseload purposes.

1 2. From this analysis, separately estimate the capacity and energy components as
2 follows:

3 a) Estimate the marginal cost of future capacity as the fixed cost of a simple
4 cycle combustion turbine (SCCT).

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

8 c) To the SCCT capacity costs add 12% reserve requirements consistent with
9 PGE's 2009 IRP.

10 3. Finally, express these capacity and energy values in real levelized terms. PGE
11 Exhibit 1504 presents the summary of these long-run marginal capacity and
12 energy cost calculations. PGE Exhibit 1504 also presents the results of how the
13 generation revenue requirement is spread to the rate schedules.

14 **Q. How did you calculate the 2011 test-period marginal capacity costs?**

15 A. We multiplied the real levelized annual capacity cost described above by the projected 2011
16 test-period peak hour load. This peak hour load is projected to occur in January.

17 **Q. How did you allocate the marginal capacity costs to each rate schedule?**

18 A. We allocated the total 2011 test period marginal capacity costs described above on the basis
19 of each schedules' relative contribution to the monthly peak hours contained in the months
20 of January, July, August, and December (4-CP).

21 **Q. Why did you choose these four monthly peaks?**

22 A. We chose these four months because they are the months with the highest peaks consistent
23 with the periods identified as capacity deficient in the 2009 IRP. We additionally chose

1 these months because for each of the past ten years PGE's highest annual peak hour
2 occurred during one of these four months.

3 **Q. How did you estimate the marginal energy costs?**

4 A. We used both the long-run real levelized marginal energy cost derived from our analysis
5 described above and the projected fully allocated cost of a generic wind farm as identified in
6 the IRP.

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

9 A. We used the proportion of new gas and renewable resources proposed for the year 2020 as
10 identified on page 320 of the IRP. This resulted in an attribution of 58% of marginal energy
11 costs to the energy costs of a CCCT as defined above, and 42% to the fully allocated costs of
12 a generic wind farm.

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

14 A. We used the long-term gas price forecast contained in our IRP for the Sumas and AECO
15 hubs. We equally weighted the projected burnertip prices from these two hubs.

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

17 A. Yes. We include compliance costs of \$30.00 per short ton (real levelized 2009\$) consistent
18 with the environmental assumptions in the IRP.

19 **Q. What is the fully allocated cost of a generic wind farm as specified in the IRP?**

20 A. On page 118 of the draft IRP issued September 4, 2009, a fully allocated wind farm is
21 estimated at \$93.62/MWh in real levelized 2011 dollars.

22 **Q. Did you modify this real levelized figure for purposes of the marginal cost study?**

23 A. Yes. Because of the two large transmission projects proposed in our IRP, we removed the
24 wheeling portion of estimated costs to be consistent with how we modeled the fully

1 allocated costs of a CCCT and the capacity costs of a SCCT. This results in a real levelized
2 marginal energy cost for wind of \$85.69/MWh.

3 **Q. How did you shape these energy costs into hourly values?**

4 A. We shaped the weighted marginal energy costs described above into hourly intervals based
5 on the energy price shaping from PGE's production cost model, Monet.

6 **Q. How did you estimate each rate schedule's marginal energy cost?**

7 A. We performed the following steps to calculate the 2011 hourly load profile and marginal
8 energy cost of each rate schedule:

9 1. For each schedule and each month, calculate a typical weekday, Saturday, and
10 Sunday load shape using 2008 hourly load profiles.

11 2. Use these day-type hourly profiles and the projected monthly peak hour loads to
12 shape each schedule's monthly test-period load forecast into hourly values.

13 3. By hour, sum each schedule's loads from 2 above and compare these hourly
14 sums to the hourly system load forecast. Assign hourly differences between the
15 two quantities on the basis of each schedule's monthly standard deviation of
16 hourly shaped loads in 2 above. These standard deviations are differentiated by
17 weekday, Saturday, and Sunday.

18 4. Multiply each schedule's shaped hourly load forecast by the corresponding
19 hourly long-term energy cost described above.

20 **Q. How does this projection of hourly interval loads compare to the monthly load forecast
21 submitted in this docket?**

22 A. The energy values by schedule match precisely. However, by inserting the projected
23 monthly peak hour loads to smoothed hourly loads, the monthly peak load hours and the
24 hourly loads immediately proximate to the peak load hours can sometimes appear to be

1 somewhat less than smooth. Nevertheless, the hourly interval data yields a more granular
2 basis to allocate the marginal cost of energy relative to simply using monthly energy values
3 and monthly loads. It furthermore is responsive to those parties in the UM 1415 workshops
4 that stated a preference for hourly marginal energy cost estimation.

5 **Q. Did you use the shaped hourly loads for any purpose other than for the marginal cost**
6 **of energy?**

7 A. Yes. We used the hourly loads to calculate the annual non-coincident peak load factors for
8 the individual rate schedules. With one exception, Schedule 38, we used the calculated load
9 factors because they provided reasonable values relative to what we have used in previous
10 dockets. For Schedule 38 we imposed a non-coincident peak load factor of 20%, consistent
11 with past practice. This 20% load factor approximates the load factor that results in
12 comparable monthly bills for both Schedules 38 and 83.

13 **Q. Please summarize how you calculate marginal distribution costs.**

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

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

18 A. We calculate subtransmission and substation marginal unit costs by first summing growth-
19 related projected capital expenditures over the five-year period 2010-2014. We then
20 annualize these capital expenditures and divide by the growth in system non-coincident
21 peak. Customers served at subtransmission voltage are not included in the substation
22 calculation because they supply their own substation.

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

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

- 1 1. Perform an analysis that places customers on the distribution feeder from which
2 they are currently served.
- 3 2. Eliminate any distribution feeders from which we cannot obtain customer
4 information, and which do not conform to “typical” standards. Examples of
5 these “non-typical” feeders are feeders serving customers at 4 kV, or network
6 feeders that serve downtown core areas.
- 7 3. Perform an inventory of the wire types and sizes for each feeder. Standardize
8 these wire types and sizes to current specifications and then calculate the cost of
9 rebuilding these feeders in today’s dollars.
- 10 4. Segregate the wire types and sizes into mainline feeders and taplines. Mainline
11 feeders are typically capable of carrying larger loads and are generally closer to
12 the substations from which they originate. Taplines are typically capable of
13 carrying smaller loads and can be remote from substations.
- 14 5. For each feeder, allocate the mainline cost responsibility of each rate schedule
15 based on the rate schedule’s proportionate contribution to non-coincident peak
16 (NCP). Calculate a unit cost per kW by totaling the feeder cost responsibilities
17 and dividing by the sum of each schedule’s NCP.
- 18 6. For each feeder, allocate the tapline cost responsibility of each rate schedule
19 based on the rate schedules proportionate design demand (distribution design
20 standard peak load). Calculate a unit cost per kW for both poly and single phase
21 customers by totaling the feeder cost responsibilities and dividing by the sum of
22 each schedule’s design demand.
- 23 7. Annualize the mainline and tapline unit costs by applying an economic carrying
24 charge.

1 8. Separately estimate the unit costs of customers greater than 4 MW who are
2 typically on dedicated distribution feeders. Calculate these marginal unit costs
3 (per customer) as the average distance between the substation and the customer-
4 owned facilities. Because new customers on dedicated circuits typically have a
5 redundant feeder, multiply this average distance by two, resulting in a per-
6 customer average of 10,800 feet of dedicated feeders. Finally, apply the annual
7 carrying charge to annualize the cost per customer.

8 9. Separately estimate the per customer cost of customers served at
9 subtransmission voltage by first calculating the average distance from the point
10 at which subtransmission voltage customers connect into the subtransmission
11 system from their substation and then multiplying this average distance by the
12 current cost per wire mile. These estimated costs are then annualized.

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

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

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

18 A. We calculate each schedule's marginal transformer and service costs by estimating the cost
19 of providing the average customer within a class with a service lateral and a line transformer
20 (secondary delivery voltage only). We also include the service design costs and any wire
21 costs not captured in the feeder portion of the study. For smaller customers, such as those
22 on Schedules 7 and 32, we estimate the average number of customers on a transformer in
23 order to appropriately calculate their service and transformer costs. Table 4 of PGE Exhibit
24 1505 summarizes these marginal transformer and service costs by schedule.

1 **Q. Why have you moved the service and transformer costs to the “customer” category**
2 **within Distribution?**

3 A. We moved this category to the customer category from the “facilities” category because we
4 believe that it is more appropriate to group these one-time hookup costs with customer-
5 related costs such as meters. As in both UE 180 and in UE 197, the applicable determinant
6 for both services and transformers is number of customers, or, in the case of transformers,
7 number of customers on a transformer. Therefore, it makes sense to reclassify these
8 distribution costs to “customer.”

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

10 A. We calculate marginal meter costs as the newly installed costs of providing AMI meters for
11 each customer and then apply an annual carrying charge. Table 5 of PGE Exhibit 1505
12 summarizes the marginal costs of meters.

13 **Q. How do you allocate distribution O&M to each distribution category and ultimately to**
14 **each rate schedule?**

15 A. We allocate test-period distribution O&M by distribution category to the rate schedules in
16 proportion to each schedule’s respective usage times its marginal capital cost. Table 6 of
17 PGE Exhibit 1505 provides the details of this allocation and the final distribution marginal
18 costs by distribution category.

19 **Q. How do you calculate the marginal costs of Metering?**

20 A. We calculate the marginal cost of the limited amount of meter reading expected to occur in
21 2011 based on a historical meter reading study. This study measures the average time per
22 rate schedule it takes to read meters including transport time. For the Network Data
23 Operations O&M, we use the number of customers less street and area lighting customers.
24 For the Meter Services portion of metering O&M, we allocate the costs in the following

1 manner: 20% to residential customers, 75% to nonresidential customers, and 5% as credit-
2 related. Finally, we allocate the remaining Metering O&M costs based on a sub-allocation
3 of the above allocations. We then divide the 2011 allocated amounts by projected 2011
4 customer counts to derive the marginal Metering cost per customer for each rate schedule.

5 **Q. How do you calculate the marginal costs of Billing?**

6 A. We allocate the collection-related cost ledgers on the same basis as the uncollectible
7 accounts. We allocate some of the cost ledgers directly on the basis of cost-causation and
8 we allocate some of the other support ledgers such as technology maintenance support based
9 on sub-allocations of the other accounts within Billing. After we allocate the various Billing
10 O&M ledgers, we divide the total allocations by the projected 2011 customer counts by
11 schedule. This result is the Billing marginal cost for each rate schedule.

12 **Q. How do you calculate the marginal costs of Other Consumer Service?**

13 A. We calculate the marginal cost of Other Consumer Service by allocating the individual cost
14 ledgers to the rate schedules based on various cost-causation principles. For example, we
15 allocate the ledger titled “Phone Response to Residential Account Inquiries” entirely to
16 residential customers. We allocate Commercial/Industrial Account Management to the
17 applicable customers based on a weighting of 20% applicable customer count and 80%
18 energy consumption. As with Billing, we allocate certain support cost ledgers based on sub-
19 allocations within the functional category. After we allocate the individual cost ledgers to
20 the individual rate schedules we divide the allocations by the test period customer count to
21 obtain a per customer marginal cost. Table 7 of PGE Exhibit 1505 contains the summary of
22 the marginal customer costs.

III. Rate Schedule Design

1 **Q. Please provide a brief summary of the major Cost of Service Rate Schedules.**

2 A. There are five major Cost of Service (COS) rate schedules:

3 **Schedule 7, Residential Service**, currently consists of a monthly Basic Charge,
4 volumetric Transmission and Distribution Charges, and a two-block energy rate. As we
5 discuss later in testimony we propose to implement a three-block energy rate.

6 **Schedule 32, Small Nonresidential Standard Service**, consists of a monthly Basic
7 Charge, a volumetric Transmission Charge, and a two-block Distribution Charge. The
8 Energy Charge is flat across all energy usage.

9 **Schedule 83, Large Nonresidential Standard Service**, is proposed to be applicable to
10 all Large Nonresidential customers between 31 and 200 kW, except for certain specialty
11 schedules. Because we have so few primary voltage customers below 200 kW, we restrict
12 this schedule to secondary service only. This schedule contains more complex charges than
13 Schedules 7 and 32. In addition to the customer charges, there is a Transmission Demand
14 Charge based on the highest metered kilowatt (kW) reading for a 30 minute period during
15 the monthly billing cycle. There is also a Distribution Demand Charge based on the same
16 criteria above, and a Distribution Facility Capacity Charge based on the average of the two
17 greatest monthly Demands within a 12-month period (Facility Capacity). The Energy
18 Charge is flat for all energy usage.

19 **Schedule 85, Large Nonresidential Service (201 to 1,000 kW) Standard Service**, is a
20 proposed new schedule. We propose this new schedule for the following reasons:

21 1) The creation of the schedule allows for a more equitable allocation of the
22 Schedule 129 transition adjustment. Previously this transition adjustment amount was

1 allocated to many Schedule 83 customers that were not eligible for the multi-year option
2 that creates the transition adjustment amounts.

3 2) Partitioning the current Schedule 83 into two rate schedules allows for improved
4 cost allocation. For example, the larger customers within the current Schedule 83 incur
5 higher customer-related costs such as representation by the Key Customer Management
6 (KCM) Group. Generally the 200 kW demand threshold is where customers are more
7 likely to be assigned to a KCM representative and also where PGE installs more
8 expensive reactive demand (kVar) metering capability. Therefore it makes sense to
9 evaluate other cost differences such as generation and distribution costs for customers
10 above 200 kW.

11 The pricing for Schedule 85 retains many of the same features as Schedule 83, but we
12 differentiate the energy charge by on and off-peak periods similar to Schedule 89. We base
13 the Transmission and Distribution Demand Charges on the 30-minute peak periods
14 occurring during on-peak intervals.

15 **Schedule 89, Large Nonresidential (>1,000 kW) Standard Service**, is a schedule for
16 customers whose Facility Capacity exceeds 1,000 kW. This schedule contains Transmission
17 and Distribution Demand Charges for which we continue to propose to charge only for the
18 30 minute periods that occur during on-peak intervals. These on-peak intervals are defined
19 as between 6:00 a.m. and 10:00 p.m., Monday through Saturday. The Schedule 89
20 Distribution Facility Capacity Charge is calculated in the same manner as for Schedules 83
21 and 85. The Energy Charges will continue to be on- and off-peak differentiated.

22 **Q. How did PGE develop the prices for each rate schedule?**

1 A. We explain the development of the prices for each of the major rate schedules below. PGE
2 Exhibit 1503, Rate Design, provides additional detail regarding how the individual prices for
3 each schedule were designed.

4 **Q. Please list the individual prices for Schedule 7, Residential Service.**

5 A. The prices are summarized below:

**Schedule 7
Residential Service Proposed Prices**

Category	Prices
Basic Charge Single Phase	\$10.00 per customer per month
Basic Charge Three Phase	\$14.00 per customer per month
Transmission & Related Service Charge	2.43 mills per kWh
Distribution Charge	33.49 mills per kWh
Energy Charge First 500 kWh	59.00 mills per kWh
Energy Charge Next 500 kWh	76.43 mills per kWh
Energy Charge Over 1,000 kWh	84.00 mills per kWh

6 **Q. Please explain how you developed these prices.**

7 A. Although the Marginal Cost Study results suggest a **Basic Charge** of approximately \$18.50,
8 we propose to maintain the single-phase charge at \$10.00. We propose to increase the three-
9 phase Basic Charge to \$14.00 based on the percent of single-phase costs recovered from the
10 \$10.00 single-phase Basic Charge. For both Schedule 7 and Schedule 32 we propose to
11 remove the Nonstandard Metering Charge that is applicable to the Time-of-Use (TOU)
12 Portfolio Option.

13 We develop the **Transmission & Related Service Charge** directly from the allocated
14 transmission and ancillary services revenue requirement.

15 We calculate the **Distribution Charge** of 33.49 mills per kWh from the allocated
16 distribution costs and from the allocated costs not recovered by the other charges. The
17 Distribution Charge also includes the allocation of franchise and OPUC fees and Trojan
18 Decommissioning costs.

1 We developed the Schedule 7 blocked **Energy Charges** based on the following
2 subjective criteria:

3 1. The price increase should approximate the overall base rate increase of 7.4% for
4 customers who consume up to 1,000 kWh monthly, the breakpoint for the second and
5 third blocks.

6 2. For Schedule 7 customers who consume 2,000 kWh monthly, the base rate
7 increase should be approximately 1.5 times the Schedule 7 base rate increase of 8.8%.
8 This helps to ensure that less than 20% of residential customers will see an increase
9 exceeding 1.5 times the residential average during the peak consumption month of
10 January.

11 3. Adjust the first and second block prices as necessary to mitigate the percent
12 changes of those customers impacted by the change in block size from 250 kWh to 500
13 kWh.

14 **Q. What is the base rate change for an average residential customer consuming 900 kWh**
15 **monthly after applying the criteria above?**

16 A. The base rate change for a Schedule 7 customer consuming 900 kWh is 6.7%. Including all
17 supplemental schedules, the change is 7.0%. PGE Exhibit 1502 provides the rate impacts at
18 various consumption levels. These rate impacts are with all supplemental schedules,
19 including the Schedule 108 Public Purpose Charge (PPC) and the Schedule 115 Low Income
20 Adjustment.

21 **Q. What is the current energy pricing structure based upon?**

22 A. The current block of 250 kWh is an anachronism from UE 115. In that docket, we stipulated
23 to this block level in order to approximate the residential share of BPA Subscription Power
24 deliveries. We have not received Subscription Power since September 2006. The current

1 difference of 1.775 cents/kWh between the blocks is a holdover from UE 180. In that
2 docket, parties stipulated to a price differential of at least 1.75 cents/kWh between the first
3 and second blocks while maintaining the UE 115 blocking at 250 kWh.

4 **Q. What is the basis of kWh blocking you propose in this case?**

5 A. The first block of 0-500 kWh monthly approximates a baseline level of usage, therefore a
6 level of usage without space conditioning or electric hot water heating for a three bedroom
7 dwelling unit. We base this statement on estimates contained in the Housing Choice
8 Program Guidebook provided by the U.S. Housing and Urban Development. This first
9 block also allows us to better manage the rate impacts for those customers consuming less
10 than 1,000 kWh monthly. We estimate that about 50% of the Schedule 7 annual
11 consumption will be priced at the first block and about 30% of the Schedule 7 consumption
12 will be priced at the higher second block of 501-1,000 kWh monthly.

13 Based on 2009 historical data, approximately 28% of Schedule 7 bills are for less than
14 500 kWh monthly and approximately 67% are for less than 1,000 kWh monthly.

15 **Q. Did you consider other Schedule 7 rate designs?**

16 A. Yes. UM 1415 discussions included suggestions for other designs such as two blocks with a
17 breakpoint at 1,000 kWh and the tailblock priced at long-run marginal cost (approximately
18 100 mills/kWh). We are open to other Schedule 7 rate designs, but customer impacts must
19 be considered.

20 **Q. Please comment on why you did not price the tailblock significantly higher than the
21 other blocks.**

22 A. We prefer to implement a more inclining block structure in a gradual manner, one that does
23 not produce significantly higher impacts for larger users immediately. Our proposed rate
24 design accomplishes this gradualism. In addition, large users comprise a significant portion

1 of past-due accounts. Gradualism helps to limit growth in uncollectible amounts and helps
2 us learn about customer responses to pricing changes.

3 **Q. Please list the individual prices for Schedule 32, Small Nonresidential Service.**

4 A. The prices are summarized below:

**Schedule 32
Small Nonresidential Service**

Category	Price
Basic Charge Single Phase	\$12.00 per customer per month
Basic Charge Three Phase	\$16.00 per customer per month
Transmission & Related Services Charge	2.28 mills per kWh
Distribution Charge First 5,000 kWh	35.41 mills per kWh
Distribution Charge Over 5,000 kWh	8.17 mills per kWh
Energy Charge	64.87 mills per kWh

5 **Q. Please describe how you developed the Schedule 32 prices.**

6 A. Schedules 32 and 532 apply to Small Nonresidential customers, whose Facility Capacity is
7 less than 30 kW. Schedule 532 (applicable to Direct Access Service) is actually a subset of
8 Schedule 32 in that it contains some, but not all, of the cost components of Schedule 32.
9 Small Nonresidential customers receive service at secondary voltage and other than the
10 Basic Charge, all charges are expressed as a volumetric kWh charge. As with Schedule 7,
11 the applicable costs are allocated into the Basic, Transmission, Distribution and Energy
12 Charge categories. We maintain the **Basic Charge** for single- and three-phase service at
13 \$12 and \$16 per month, which are considerably below the marginal customer-related costs.
14 As with Schedule 7, we capture the difference between the allocated costs and the various
15 revenues within the Distribution Charge.

16 We compute the **Transmission and Related Services Charge** directly from the
17 allocated transmission and ancillary service costs.

18 We retain the current Schedule 32, **Distribution Charge** blocking, with the initial block
19 including usage up to 5,000 kWh. We set the second block for usage greater than 5,000

1 kWh on a declining basis to 5.00 mills per kWh (prior to adding the System Usage Charge)
2 in order to provide a transition to Schedule 83 for customers whose loads have exceeded 30
3 kW at least twice during the preceding 13 months. We set this tailblock rate at a higher
4 level than in UE 197 consistent with the increased price for the first block. The design
5 provides effective rate migration for customers who migrate from volumetric-based
6 distribution pricing to demand-based distribution pricing (Schedule 32 to 83). Similar to
7 Schedule 7, we include within the Distribution Charge the costs associated with franchise
8 and OPUC fees and Trojan Decommissioning.

9 We set the **Energy Charge** on a flat year-round basis that is based on the allocation of
10 generation costs.

11 **Q. Briefly describe Schedule 532.**

12 A. Schedule 532 sets out the charges associated with PGE's transmission and distribution
13 services. Energy supply and transmission costs are excluded because the customer's Energy
14 Service Supplier (ESS) provides these services.

15 Schedule 532 includes the same Basic and Distribution Charges as Schedule 32. We
16 incorporate a Daily Price Energy Charge into Schedule 32 in order to address the potential
17 cost impact of customers switching from Schedule 532 to Schedule 32 prior to completing at
18 least one year of service on Schedule 532. The daily price tracks the daily market price for
19 power and is based on the secondary voltage Daily Price option in Schedule 83.

20 **Q. Please provide the proposed prices for Schedule 83 and describe the customers to
21 whom these prices apply.**

22 A. Schedule 83 applies to all Nonresidential customers with Facility Capacity loads greater
23 than 30 kW and less than or equal to 200 kW. Those customers whose load exceeds 200 kW
24 will take service under Schedule 85, which we discuss below. We use the same approach

1 and cost causation principles as described for Residential and Small Nonresidential service
2 in designing these rates.

3 The Schedule 83 charges include more detail because Large Nonresidential customers
4 are generally more sophisticated energy users and are more able to react to pricing signals
5 triggered by their peak consumption. Schedule 83 is for secondary delivery voltage only.
6 We limit this to secondary voltage in order to reduce the administrative burden of separately
7 maintaining an option for only about 20 accounts below 200 kW that are served at primary
8 voltage. We propose that these 20 accounts be billed at Schedule 83 prices, after applying
9 the 1.5% adjustment to meter data as specified in Rule M-4. The proposed prices are below:

**Schedule 83
General Service 31-200 kW**

Category	Monthly Price
Basic Charge Single Phase	\$20.00 per customer per month
Basic Charge Three Phase	\$30.00 per customer per month
Trans. & Related Services	\$ 0.88 per kW peak Demand
Distribution Demand Charge	\$ 1.83 per kW peak Demand
Facility Capacity Charge (First 30 kW)	\$ 3.00 per kW Facility Capacity
Facility Capacity Charge (Over 30 kW)	\$ 2.50 per kW Facility Capacity
System Usage Charge	3.80 mills per kWh
COS Energy Charge	64.13 mills per kWh

10 **Q. Please describe how you developed the Schedule 83 prices.**

11 A. We maintain the Schedule 83 single-phase **Basic Charge** at \$20.00 and increase the
12 three-phase charge to \$30.00. This pricing level helps enable a smoother transition for
13 Schedule 32 customers whose demand exceeds 30 kW. Similar to Schedule 32, these basic
14 charges are set considerably below the marginal customer-related costs. The System Usage
15 Charge recovers the remaining customer-related costs as well as any other costs either not
16 fully recovered or more than fully recovered through the appropriate charge.

17 For Schedules 83, 85, and 89, we set the **Transmission & Related Service Charge** to
18 \$0.88 per kW consistent with the other secondary voltage customers served on Schedules 85
19 or 89. We do this to make the pricing more consistent for customers who choose Direct

1 Access Service under Schedules 583, 585 or 589. This charge results in more than a full
2 recovery of Schedule 83 allocated costs, consequently we flow the over recovery through to
3 the System Usage Charge.

4 The **Distribution Charges** for Schedule 83 consist of a **Demand Charge** and a **Facility**
5 **Capacity Charge**. We recover the costs associated with the 13 kV system through the
6 Facility Capacity Charge. We set the Facility Capacity Charge for the first 30 kW at a lower
7 level than the Facility Capacity Charge for over 30 kW to once again provide a smooth
8 transition for Schedule 32 customers who migrate to Schedule 83 because their Demand
9 exceeds 30 kW.

10 The **Demand Charge** of \$1.83 recovers the allocated revenue requirement of
11 substations and the 115 kV system.

12 Because several energy options are available to Schedules 83 and 583, we separately
13 state the **System Usage Charge**. This charge recovers franchise and OPUC fees and Trojan
14 Decommissioning costs, as well as any other costs not fully recovered by the other charges.

15 **Q. Please describe the Schedule 83 Energy Charge options.**

16 A. Schedule 83 customers may choose to receive energy either from PGE based on PGE's COS
17 energy option or from PGE's market-based energy option. The market-based option
18 available to Schedule 83 is daily pricing based on the prices for the Mid-Columbia hub as
19 reported by the Dow Jones Mid-Columbia Daily On- and Off-Peak Firm Pricing Index (Dow
20 Jones). We propose to eliminate the current monthly Fixed Price Option due to a lack of
21 customer interest in this pricing option. Customers may also choose to receive service from
22 an ESS.

1 We propose that customers receiving service from an ESS or from a PGE market option
 2 continue to receive the Schedule 128, Short-Term Transition Adjustment in the same
 3 manner as they currently do.

4 **Q. What schedule is applicable to Schedule 83 customers who wish to elect the Direct**
 5 **Access energy option?**

6 A. Customers choosing the Direct Access energy option will take service under the provisions
 7 of Schedule 583. Schedule 583 pricing mirrors Schedule 83 except that it contains neither a
 8 PGE-supplied energy price, nor a Transmission & Related Services Charge.

9 **Q. Please provide the proposed monthly prices for Schedule 85 and describe the**
 10 **customers to whom these prices apply.**

11 A. Schedule 85 applies to all Large Nonresidential customers whose Facility Capacity demands
 12 are between 201 kW and 1,000 kW. Those customers whose facility capacity exceeds 1,000
 13 kW take service under Schedule 89 which we discuss below. We base the individual
 14 charges on the results of the marginal cost study and subsequent ratespread, paying
 15 particular attention to appropriately pricing the cost differentials between secondary and
 16 primary delivery voltages. The prices differentiated by delivery voltage are below:

Schedule 85 General Service 201-1,000 kW

Category	Secondary Price	Primary Price
Basic Charge	\$400.00 per customer per month	\$360.00 per customer per month
Trans. & Related Services	\$ 0.88 per kW peak Demand	\$ 0.85 per kW peak Demand
Distribution Demand Charge	\$ 1.95 per kW peak Demand	\$ 1.88 per kW peak Demand
Facility Capacity Charge (First 200 kW)	\$ 2.04 per kW Facility Capacity	\$ 1.97 per kW Facility Capacity
Facility Capacity Charge (Over 200 kW)	\$ 2.04 per kW Facility Capacity	\$ 1.97 per kW Facility Capacity
System Usage Charge	4.00 mills per kWh	3.86 mills per kWh
COS Energy Charge On-peak	65.39 mills per kWh	63.47 mills per kWh
COS Energy Charge Off-peak	53.60 mills per kWh	51.68 mills per kWh

17 **Q. Please describe how you developed the Schedule 85 prices.**

1 A. The Schedule 85 **Basic Charges** differ by delivery voltage. For secondary service and
2 primary voltage, we set the Basic Charges at \$400.00 and \$360.00 per month respectively.
3 These customer charges fully recover (subject to rounding) the allocated marginal customer-
4 related costs. These customer charges combined with the flat facilities charge blocking
5 provide a smooth transition for those Schedule 83 customers whose demand grows to exceed
6 200 kW. This pricing also provides for a better transition for those Schedule 85 customers
7 whose demand exceeds 1,000 kW, thereby migrating to Schedule 89.

8 For Schedules 83, 85, and 89, we set the **Transmission & Related Service Charge** to
9 \$0.88 per kW for secondary service, and at \$0.85 per kW for primary service, prices that are
10 slightly higher than the allocated revenue requirements.

11 The **Distribution Charges** for Schedule 85 consist of a **Demand Charge** and a **Facility**
12 **Capacity Charge**. For both secondary and primary voltage customers, we recover the costs
13 associated with the 13 kV system through the Facility Capacity Charge. The difference
14 between secondary and primary voltage Facility Capacity Charges reflect the difference in
15 peak demand losses for the respective delivery voltages. The facilities charge also recovers
16 any over or under recovery of the other charges.

17 The **Demand Charges** of \$2.04 and \$1.97 for secondary and primary customers
18 respectively recover the allocated revenue requirement of substations and the 115 kV
19 system. We calculate the demand charge difference based on the difference in peak demand
20 losses of the respective delivery voltages.

21 Because several energy options are available to Schedules 85 and 585, we separately
22 state the **System Usage Charge** which recovers franchise and OPUC fees, Trojan
23 Decommissioning costs, the Schedule 129 transition adjustment, and the CIO. We also use
24 this charge for both Schedules 85 and 89 to capture the Schedule 129 transition adjustment

1 and the generation fixed cost contributions of either returning or departing long-term direct
2 access customers.

3 We calculate the COS **Energy Charge** based on the results of the generation
4 allocations. We use a 2011 projection of on- and off-peak differentiated Mid-Columbia
5 forward curves to establish the time-differentiated energy charges. We calculate the energy
6 price difference between the secondary and primary voltage customers based on the
7 difference in embedded line losses. We believe that in the future, for both Schedules 85 and
8 89, we should move more towards pricing these differentials based on the losses of newly
9 installed equipment rather than the embedded line losses. In this manner, customers will
10 receive a more accurate price signal regarding PGE’s marginal costs and a stronger incentive
11 to purchase more energy-efficient transformers.

12 **Q. Please describe the Schedule 85 Energy Charge options.**

13 A. The Schedule 85 energy price options are the same as those for Schedule 83 described
14 above.

15 **Q. Please provide the proposed monthly prices for Schedule 89 and describe the**
16 **customers to whom these prices are applicable.**

17 A. Schedule 89 applies to all Large Nonresidential customers whose Facility Capacity exceeds
18 1,000 kW. Because of their unique characteristics we separately identify the distribution
19 costs for customers whose loads exceed 4,000 kW and integrate these cost differences into
20 the Schedule 89 pricing for service to secondary, primary, and subtransmission delivery
21 voltages. The charges are based on the Marginal Cost Study with attention to billing
22 impacts and the cost differentials between delivery voltages. The Schedule 89 prices
23 differentiated by delivery voltage are below:

Schedule 89 General Service Greater than 1,000 kW

Category	Secondary	Primary	Subtransmission
Basic Charge	\$1,310.00 per month	\$1,040.00 per month	\$2,020.00 per month
Transmission & Related Charge	\$ 0.88 per on-peak kW	\$0.85 per on-peak kW	\$0.84 per on-peak kW
Facility Capacity Charge First 4,000 kW	\$ 1.77 per kW Facility Capacity	\$1.73 per kW Facility Capacity	\$1.73 per kW Facility Capacity
Facility Capacity Charge Over 4,000 kW	\$ 0.38 per kW Facility Capacity	\$0.34 per kW Facility Capacity	\$0.34 per kW Facility Capacity
Distribution Demand Charge	\$ 2.05 per on-peak kW	\$1.98 per on-peak kW	\$0.91 per on-peak kW
System Usage Charge	4.27 mills per kWh	4.03 mills per kWh	3.89 mills per kWh
COS Energy Charge On-peak	63.24 mills per kWh	61.36 mills per kWh	60.54 mills per kWh
COS Energy Charge Off-peak	51.45 mills per kWh	49.57 mills per kWh	48.75 mills per kWh

1 **Q. Please describe how you developed the Schedule 89 Charges.**

2 A. We set the **Basic Charges** for secondary, primary and subtransmission voltage customers at
 3 approximately 90% of the marginal-customer-related costs with any under-collection
 4 captured by the Facility Capacity Charges. For customers served at subtransmission voltage
 5 this is an increase of \$1,020 per month over the current monthly charge.

6 **The Transmission and Related Service Charge** is calculated in conjunction with
 7 Schedules 83 and 85 for the reasons previously discussed. Because this charge is less than
 8 the allocated costs, the Facility Capacity Charge recovers the remainder.

9 **The Distribution Demand Charge** for both secondary and primary voltage customers
 10 reflects the marginal cost of providing substations and shared subtransmission facilities. For
 11 customers served at subtransmission voltage who supply their own substation, the
 12 Distribution Demand Charge reflects the marginal cost of the shared subtransmission
 13 system. It also reflects the cost per kW differential between connecting a customer of equal
 14 size with a 13 kV feeder or a feeder at 115 kV. This differential of seven cents/kW is added
 15 to the Distribution Demand Charge to equalize the Facility Capacity Charge for primary
 16 voltage and subtransmission voltage delivery. As with Schedule 85, we set the delivery
 17 voltage price differentials based on the peak demand loss differences of the respective
 18 delivery voltages.

1 The **Facility Capacity Charge** for Schedule 89 customers has two blocks; one for the
2 first 4,000 kW, and the second for billing kW greater than 4,000 kW. Previously we
3 blocked this schedule at 1,000 kW, but the proposed blocking is more reflective of
4 distribution cost differences within the schedule. The first block facilitates the migration of
5 customers from Schedules 85/585, while the second block captures the remaining facilities-
6 related revenue requirements of Schedule 89 customers. Both Facility Capacity Charge
7 blocks reflect the peak demand loss difference between providing service at secondary or
8 primary voltage service. As mentioned above, we set the Facility Capacity Charge for
9 subtransmission voltage customers equal to that of primary voltage customers and flow any
10 cost difference to the subtransmission voltage Demand Charge.

11 The **COS Energy Charge** option for Schedule 89 is on- and off-peak differentiated by
12 delivery voltage. A Daily Price option is also available similar to that described for
13 Schedule 83. Customers who wish to pursue the Direct Access Energy Option will take
14 service under Schedule 589. As with Schedules 83/583 and 85/585, Schedules 89 and 589
15 separately identify the System Usage Charge.

16 **Q. Describe the development of charges for the remaining rate schedules.**

17 A. The remaining proposed rate schedules, with one exception, provide service to lighting and
18 irrigation customers and are discussed below:

19 We structure **Schedule 15, Outdoor Area Lighting Standard Service**, charges in the
20 same manner as the current rate schedule. The Monthly Charge contains all of the allocated
21 costs based on the specific kWh usage by luminaire. Schedule 515 provides this customer
22 class with Direct Access Service charges.

23 **Schedule 38, Large Nonresidential Optional Time-of-Day Standard Service** is, as
24 its name implies, an optional schedule that is applicable to customers whose facility capacity

1 is between 31 and 200 kW. We keep the monthly Basic Charges for single- and three-phase
2 service at \$20.00 and \$25.00 dollars respectively. We maintain the volumetric recovery of
3 transmission and distribution costs and continue to differentiate the energy charges based on
4 the on- and off-peak periods defined in Schedule 38.

5 **Schedule 47, Irrigation and Drainage Pumping Small Nonresidential Standard**
6 **Service**, applies to Small Nonresidential customers whose demand does not exceed 30 kW.
7 We retain both the monthly Basic Charge at \$25.00 per month for the six summer months
8 only, and the blocked Distribution Charge. Schedule 47 customers may take Direct Access
9 Service under Schedule 532.

10 **Schedule 49, Irrigation and Drainage Pumping Large Nonresidential Standard**
11 **Service**, is similar to Schedule 47, but applies to customers larger than 30 kW. We retain
12 the Basic Charge of \$30 per month, summer months only. Similar to Schedule 47, we
13 continue to block the Distribution Charge. Schedule 549 states the Direct Access charges
14 for these customers. These customers are also eligible for Direct Access Service on
15 Schedules 583 or 585.

16 **Schedules 91/591, Street and Highway Lighting Standard Service**, provides
17 municipalities with outdoor lighting service. These schedules are similar in structure to
18 Schedule 15. Each service option monthly rate includes the applicable unbundled costs,
19 based on the monthly kWh usage of the particular type of light.

20 **Schedule 92, Traffic Signals Standard Service**, is an energy-only rate for un-metered
21 traffic control devices in systems with at least 50 intersections. We retain the energy-only
22 nature of the rate.

1 **Schedule 592, Traffic Signals Direct Access Service**, provides the Direct
2 Access-related energy-only based charge for this specialty service. Schedules 92/592
3 remain grandfathered services closed to additional governmental agencies.

4 **Schedule 93, Recreational Field Lighting Standard Service**, rate design maintains
5 the Basic Charge of \$30 per month, with Distribution and Transmission Charges recovered
6 on a volumetric basis.

7 **Q. Please describe the Area and Streetlighting Cost of Service Study.**

8 A. Streetlighting and Area Lighting prices include the costs of investment and maintenance in
9 addition to the Transmission, Distribution and production-related charges that apply to all
10 other schedules. We analyze the investment and maintenance costs components separately.
11 For the investment component, we used the historical investment rates determined in
12 UE 197 to estimate the total 2011 test-period investment revenue requirement. We estimate
13 the maintenance component based on the expected cost of maintaining each type of lighting
14 equipment and the frequency of maintenance.

15 PGE Exhibit 1506 summarizes the results of this study. This exhibit details the
16 proposed energy charges, fixed charges, total charges, and total revenues for both Area and
17 Street lighting.

18 **Q. Why and how do you limit the amount of increase to some rate schedules?**

19 A. The pricing for Schedules 47 and 49 is established at rates that are significantly less than the
20 cost to serve. This is also true, but to a lesser degree for Schedules 38 and 93. If we were to
21 price these schedules at cost, they would experience significantly greater rate increases than
22 average. This issue has existed for quite some time for Schedules 47 and 49, and our
23 changes in marginal cost methodology and ratespread have considerably exacerbated the
24 issue in this docket. Consistent with past practice we therefore propose to limit Schedules

1 38, 47, 49, and 93 to two times the overall base rate increase. We also propose to limit the
2 subsidy to the lesser of 9.5 cents/kWh or a volumetric subsidy that ensures that the irrigation
3 schedules do not receive a decrease in their distribution charges through which the CIO
4 subsidy is applied. Over time, we will gradually move these schedules closer to cost of
5 service while gradually sending the appropriate price signal.

6 **Q. Why do you limit the major rate schedules to 1.25 times the average change in this**
7 **docket?**

8 A. We do so because of the significant changes in marginal cost estimation and ratespread we
9 propose in this case. We furthermore wish to limit all of our major rate schedules increase
10 to single digits in percent terms. However, should the base rate increase fall below 6%, we
11 favor increasing the CIO limit to a range of 1.33 to 1.5 times the average increase for the
12 major rate schedules.

13 **Q. Which schedules bear the costs of mitigation of the schedules mentioned above?**

14 A. We propose that Schedules 85 and 89 bear the majority of the mitigation burden because
15 their increase is significantly below the average increase, even after paying for the
16 mitigation. Schedules 15, 91, and 92 also contribute to the rate mitigation for the same
17 reason.

18 **Q. How do you implement the CIO mitigation?**

19 A. We increase the System Usage Charges for Schedules 85 and 89, and the distribution
20 charges for Schedules 15, 91, and 92 to offset the effect of the price mitigation efforts
21 described above. Schedules receiving the CIO subsidy do so through their distribution
22 charges. We also use the CIO to equalize the distribution charges for the outdoor lighting
23 schedules 15 and 91. PGE Exhibit 1503 shows the development of this offset.

IV. Other Rate Schedule Changes

1 **Q. Please describe Schedule 145, the Boardman Power Plant Operating Life Adjustment.**

2 A. Schedule 145 is proposed as an automatic adjustment clause that implements the revenue
3 requirement changes resulting from a Commission-authorized change in the Boardman Coal
4 Plant's currently assumed end-of-life. The schedule proposes that revenue requirement
5 changes be spread on an equal percent of Energy Charge revenues, exempting Schedules
6 76R, 485, and 489. PGE Exhibit 1501 explains the intent and general function of Schedule
7 145. The rate is initially set at zero and will be adjusted as necessary consistent with the
8 provisions of the schedule.

9 **Q. Please describe Schedule 141, the Pension Adjustment Mechanism.**

10 A. Schedule 141 is also proposed as an automatic adjustment clause. It tracks the differences in
11 pension expense and financing costs on incremental cash contributions relating to the
12 employee pension program. We propose that these differences be spread on an equal
13 percent of revenues basis. PGE Exhibit 1501 further explains the operation of this
14 supplemental adjustment schedule. The rates for 2011 are set to zero.

15 **Q. Do you propose to continue Schedule 123, the Sales Normalization Adjustment?**

16 A. Yes. We propose to make Schedule 123 an ongoing decoupling mechanism that continues
17 to align customer and PGE interests in pursuing energy efficiency. The current Schedule
18 123 was implemented just over one year ago with an initial two year term. In order for PGE
19 to continue the mechanism, PGE must request an extension either by separate filing, or as
20 part of a general rate filing. With this filing we are requesting the extension of Schedule
21 123.

22 PGE Exhibit 1507 contains an assessment of the mechanism that responds to the six
23 questions the Commission posed in Order No. 09-020. The assessment shows that the

1 decoupling pilot has functioned consistent with the intent of the mechanism.
2 Notwithstanding our limited experience to date, decoupling is expected to provide benefits
3 to both customers and PGE. These benefits include aligning customer and PGE interests to
4 remove contradictory regulatory incentives towards increased energy efficiency.

5 **Q. Please describe the limited changes you propose to Schedule 123, the Sales**
6 **Normalization Adjustment.**

7 A. First, we propose to update the SNA reference prices consistent with changes in unit fixed
8 and variable charges for both Schedules 7 and 32.

9 Second, we propose to similarly update the Lost Revenue Recovery Adjustment for the
10 other applicable schedules.

11 Third, we propose to remove the provision in Special Condition 3 that allows balances
12 in excess of the 2% rate impact to be carried over from one year to the next. This change
13 effectively creates an annual “hard cap” on amounts that can be recovered and is consistent
14 with OPUC Order No. 09-176.

15 Finally, we propose to remove Special Condition 4 in order to allow Schedule 123 to
16 continue beyond the pilot termination date of January 31, 2011.

17 **Q. Do you propose to make this schedule conform to an annual period rather than the**
18 **current February through January period?**

19 A. Yes. We propose that for 2011 only, the SNA portion (Schedules 7 and 32) of Schedule 123
20 be calculated on an eleven month basis presuming that January sales per customer are at
21 forecast levels. This allows for an eventual transition to a calendar basis beginning in 2012
22 and it allows for January 2011 to be incorporated into the February 2010 to January 2011
23 period consistent with Order No. 09-020.

24 **Q. Do you propose other procedural changes to Schedule 123?**

1 A. No. The Schedule 123 Sales Normalization Adjustment process requires that PGE file by
2 April 1, the proposed Schedule 123 prices, effective June 1. For the first year, we expect a
3 refund for Schedule 7 and a surcharge for Schedule 32.

4 **Q. What changes do you propose to Schedule 126?**

5 A. We propose to change the Earnings Test section to remove the earnings deadbands. We also
6 propose to change the Negative Annual Power Cost Deadband and the Positive Annual
7 Power Cost Deadband sections consistent with the testimony contained in PGE Exhibit 200.

8 **Q. Why are you proposing to change the Schedule 300 prices?**

9 A. We propose to change the Service of Limited Duration prices in order that they reflect more
10 current cost estimates. The current prices recover only approximately 55% to 76% of the
11 estimated costs of providing these services. The detailed calculations for the proposed
12 prices are contained in the Pricing work papers.

13 **Q. Have the appropriate test-period revenue and expense accounts been adjusted to
14 reflect the proposed Schedule 300 price changes?**

15 A. Not yet. The appropriate level of expense and revenue associated with these activities will
16 have to be adjusted when PGE next updates its 2011 test period revenue requirements.

V. Qualifications

1 **Q. Mr. Kuns, please state your educational background and qualifications.**

2 A. I graduated from Linfield College in 1973 with a Bachelor of Arts in Economics. I received
3 a Master in Business Administration degree from Claremont Graduate School.

4 In 1979, I joined PGE in the Rates and Regulatory Affairs Department and have held
5 various positions in the regulatory, marketing, and planning areas. My current position is
6 Manager of Pricing and Tariffs.

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

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

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

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

15 A. Yes.

List of Exhibits

<u>PGE Exhibit</u>	<u>Description</u>
1501	Proposed Tariff Changes
1502	Estimated Impact of Proposed Changes on Customers
1503	Rate Design
1504	Allocation of Costs to Customer Classes
1505	Marginal Cost of Service Study
1506	Streetlight and Area Lights
1507	Assessment of the Sales Normalization Adjustment