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Douglas C. Tingey
Associate General Counsel

August 28, 2015

Via Electronic Filing and U.S. Mail

Oregon Public Utility Commission
Attention: Filing Center
P.O. Box 1088
Salem OR 97308-1088

Re: UE 294 – PGE's General Rate Revision

Attention Filing Center:

Enclosed for filing in the above-referenced docket is the **Second Partial Stipulation** and **Joint Testimony in Support of Second Partial Stipulation** between Portland General Electric Company, Staff of the Public Utility Commission of Oregon, the Citizens' Utility Board of Oregon, the Industrial Customers of Northwest Utilities, and Fred Meyer Stores and Quality Food Centers, Division of The Kroger Co., collectively, the Stipulating Parties. These documents are being filed by electronic mail with the Filing Center.

Thank you in advance for your assistance.

Sincerely,

Douglas C. Tingey
Associate General Counsel

DCT:jrb
Enclosures

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

UE 294

In the Matter of PORTLAND GENERAL ELECTRIC COMPANY Request for a General Rate Revision.	**SECOND PARTIAL STIPULATION**

This Partial Stipulation ("Stipulation") is between Portland General Electric Company ("PGE"), Staff of the Public Utility Commission of Oregon ("Staff"), the Citizens' Utility Board of Oregon ("CUB"), the Industrial Customers of Northwest Utilities ("ICNU"), and Fred Meyer Stores and Quality Food Centers, Division of The Kroger Co. ("Kroger") (collectively, the "Stipulating Parties"). The Small Business Utility Advocates also participated in settlement discussions and does not oppose this Stipulation. No other parties participated in the settlement discussions.

On June 23, 2015, a Partial Stipulation resolving a number of revenue requirement issues was filed in this docket. Since that time the Stipulating Parties have held numerous settlement conferences to address issues raised in the testimony filed in this docket. All power cost issues except one, and all revenue requirement issues, were settled on July 8 and 9, 2015, subject to satisfactory settlement of rate spread and rate design issues. On July 17, 2015, the parties settled all rate spread and rate design issues. As a result, when coupled with the previously filed Partial Stipulation, the parties had reached settlement of all issues in this docket except one power cost issue. That power cost issue related to the length of the maintenance outage for the Port Westward I plant as modeled in PGE's 2016 power cost forecast. A settlement conference was held on August 7, 2015, and the parties settled the one remaining power cost issue. As a result, this Second Partial Stipulation resolves all remaining issues in this docket, and the Stipulating Parties request adoption of this Second Partial Stipulation, along with the previously filed Partial Stipulation.

TERMS OF SECOND PARTIAL STIPULATION

1. This Partial Stipulation resolves the issues identified below.

    a. Load Forecast (I-5). In settlement of all load forecast issues, the Stipulating Parties agree:

        i. PGE will exclude in this rate case the price adjustment in the residential and non-residential load forecast.

        ii. PGE will work with Staff to compile a historical series of achieved energy efficiency with a goal of compiling data at the most reasonable disaggregate level, and will work with Staff to consider alternative forecasting modeling methods that incorporate energy efficiency.

        iii. PGE will work with Staff and other parties to understand PGE's load forecasting model. Staff and interested parties are also encouraged to participate in IRP workshops and meetings pertaining to or including load forecasting.

        iv. If in a subsequent docket PGE's load forecast explicitly accounts for a price effect, PGE agrees to work with the other interested parties to evaluate models that incorporate a marginal price variable into the base forecast.

b. Portfolio Options (I-8). To settle issues regarding cost allocation for renewable portfolio options, the parties agree that:

i. PGE will audit the costs allocated to the voluntary portfolio options programs and customers, and work with Staff and interested parties, including the Portfolio Options Committee, to examine the cost allocation methodology and approach. This will be done and reviewed with Staff and the Portfolio Options Committee by November 2015. PGE will follow up on audit results with any necessary tariff filing.

ii. Every three years after this audit, or more frequently if requested by Staff or another Stipulating Party, the allocation of costs to these portfolio options will be examined in the same manner.

c. Tariff Schedule 300 (I-10). Charges for Non-Network Residential Meter Rates will be set at: Installation of non-network meter: $100

Non-network Meter Read: $45 per month.

The parties further agree that PGE should make other tariff changes necessary such that customers opting for a non-network residential meter are not eligible for time-of-use rates.

d. Rate base (ICNU -1). To resolve all rate base issues raised by all parties, PGE's test-year rate base will be reduced by $18.7 million. The rate base reductions in this Stipulation and the Partial Stipulation do not incorporate the effects of Docket No. UP 310; rate base will be further reduced in the event the Commission approves the sale of poles to the City of Portland in that docket.

e. Other revenues (CUB-3). The test-year forecast of Other Revenues will be increased by $1.5 million.

f. Power costs (PC-1, PC-2, CUB-8, CUB-9, CUB-10, ICNU-7, ICNU-8, ICNU-10). In settlement of remaining power cost issues, test-year power costs will be reduced by $7.5 million. Planned maintenance for Port Westward I included in the 2016 power cost forecast will be consistent with the forecast included in PGE's April 1, 2015, MONET update. This settles all other power cost issues including California trading margins, the 2016 forced outage rate for Coyote Springs, the Super Peak Energy Purchase, load net of wind reserves, pipeline capacity release credits, the Carty modeled online date, and all other power cost issues raised in this docket. In addition to the $7.5 million reduction in power costs:

   i. PGE will propose a method for forecasting California trading margins in its next Annual Power Cost Update filing (i.e., April 1, 2016), under tariff Schedule 125.

   ii. The parties request that the Commission open a docket to address the forecasting of forced outage rates for natural gas generating plants, specifically whether there should be limits on the length of historical forced outages included in the four-year rolling average.

g. Cost of Capital (S-0, S-3, CUB-7). Revenue requirement should be set using a 9.6% return on equity, and a 50% equity, 50% debt capital structure. In settlement of cost of capital and all other issues in this docket, PGE's revenue requirement will be reduced by $4 million. Cost of debt will be updated later this year to incorporate actual 2015 debt costs, including any new issuances priced by PGE, no later than November 1, 2015. PGE will base the cost of debt update on Exhibit Staff/207C, including all updates to that document provided by Staff in July 2015 and any additional bond issuance detail for 2015. Accordingly, the revenue requirement impact of this stipulation may change.

h. PCAM (CUB-6). There will be no change in this docket to the deadbands currently contained in PGE's Annual Power Cost Variance Mechanism (PCAM) tariff, Schedule 126.

i. Marginal Cost (I-4, I-6, ICNU-2, ICNU-3). In settlement of all marginal cost issues the parties agree that in this docket:

   i. The cost of Port Westward 2 will be included as an energy cost for purposes of integrating wind energy.

   ii. The marginal cost of billing will be reduced to account for paperless billing as proposed in Staff's testimony.

   iii. Marginal capacity costs will be calculated as proposed by PGE.

   iv. Fixed pipeline costs of the marginal resource used in the marginal cost study will be included when calculating capitalized energy costs, as proposed by ICNU.

   v. All other elements of the marginal cost calculation will be consistent with the methodology presented in PGE's initial filing.

j. Ratespread and Rate Design. All ratespread and rate design issues are settled as follows:

i. Transmission revenue requirement (Staff I-1, CUB-4). Transmission revenue requirement will be allocated 25% based on energy, and 75% based on coincident peaks in the months of January, July, August, and December.

ii. Schedule Consolidation and Customer Impact Offset (Staff I-1). As part of this settlement, tariff Schedules 47 and 49 will not be priced in a manner that presumes future consolidation with Schedules 32 and 38 respectively. Schedules 38 will be priced at cost-of-service. The rate increase in this docket for Schedules 47 and 49 will be set at the greater of 13.5% or three times the overall base rate increase, excluding supplemental schedules, after inclusion of the Carty plant. Schedule 32 will bear the burden of mitigating the Schedule 47 price increase, and Schedules 83 and 85 will bear the burden of mitigating the Schedule 49 price increase.

iii. Schedule 7 Basic Charge (Staff I-1, CUB-5). The Basic Charge for Schedule 7 customers will be set at $10.50.

iv. Schedule 143 (Staff I-9). Amortization of the refund from the Trojan Nuclear Decommissioning Trust Fund under Schedule 143 will be modified as follows: Beginning January 1, 2016, Schedule 143 prices will be set to zero. Starting at the same time as the Carty plant is included in rates, Schedule 143 prices will be set to refund over the remainder of 2016 the amount that otherwise would have been amortized over 2016 if the change above had not been implemented. Beginning January 1, 2017, Schedule 143 prices will be set to amortize the remaining balance of the refund over calendar year 2017.

v. Load Following Credit (ICNU-4). The Schedule 90 load following credit will be increased in this docket from the current $1.13/MWh to $2.00/MWh. The portion of the credit in current rates ($1.13/MWh for 150 average megawatts) will be allocated to all customers. The increased amount ($0.87/MWh) will be allocated to Schedule 89 customers. In its next general rate case, PGE agrees to complete a study to evaluate the marginal cost of load following and other related ancillary services.

vi. Schedules 75 and 575 (ICNU-5). The Special Conditions in Schedules 75 and 575 will be modified as proposed by ICNU to require notice by PGE to partial requirements customers before PGE proposes a change to their baseline demand.

vii. Franchise Fees (ICNU-6). Franchise fee expenses will be allocated as originally proposed by PGE in this docket.

viii. Maintenance expenses (Kroger-1). Prior to its next rate case, PGE will evaluate the maintenance costs of secondary voltage conductors and the applicability of those costs to specific rate schedules and delivery voltages.

2. All other issues raised in this docket not otherwise specifically addressed above have been settled with no adjustments.

3. The Stipulating Parties recommend and request that the Commission approve the

adjustments and provisions described herein as appropriate and reasonable resolutions of the identified issues in this docket.

4. The Stipulating Parties agree that this Stipulation is in the public interest, and will contribute to rates that are fair, just and reasonable, consistent with the standard in ORS 756.040.

5. The Stipulating Parties agree that this Stipulation represents a compromise in the positions of the Stipulating Parties. Without the written consent of all of the Stipulating Parties, evidence of conduct or statements, including but not limited to term sheets or other documents created solely for use in settlement conferences in this docket, are confidential and not admissible in the instant or any subsequent proceeding, unless independently discoverable or offered for other purposes allowed under ORS 40.190.

6. The Stipulating Parties have negotiated this Stipulation as an integrated document. The Stipulating Parties, after consultation, may seek to obtain Commission approval of this Stipulation prior to evidentiary hearings. If the Commission rejects all or any material part of this Stipulation, or adds any material condition to any final order that is not consistent with this Stipulation, each Stipulating Party reserves its right: (i) to withdraw from the Stipulation, upon written notice to the Commission and the other Parties within five (5) business days of service of the final order that rejects this Stipulation, in whole or material part, or adds such material condition; (ii) pursuant to OAR 860-001-0350(9), to present evidence and argument on the record in support of the Stipulation, including the right to cross-examine witnesses, introduce evidence as deemed appropriate to respond fully to issues presented, and raise issues that are incorporated in the settlements embodied in this Stipulation; and (iii) pursuant to ORS 756.561 and OAR 860-001-0720,

to seek rehearing or reconsideration, or pursuant to ORS 756.610 to appeal the Commission's final order.

7. This Stipulation will be offered into the record in this proceeding as evidence pursuant to OAR 860-001-0350(7). The Parties agree to support this Stipulation throughout this proceeding and in any appeal, and provide witnesses to support this Stipulation (if specifically required by the Commission), and recommend that the Commission issue an order adopting the settlements contained herein. By entering into this Stipulation, no Stipulating Party shall be deemed to have approved, admitted or consented to the facts, principles, methods or theories employed by any other Stipulating Party in arriving at the terms of this Stipulation. Except as provided in this Stipulation, no Stipulating Party shall be deemed to have agreed that any provision of this Stipulation is appropriate for resolving issues in any other proceeding.

8. This Stipulation may be signed in any number of counterparts, each of which will be an original for all purposes, but all of which taken together will constitute one and the same agreement.

DATED this 28th day of August, 2015.

PORTLAND GENERAL ELECTRIC COMPANY

STAFF OF THE PUBLIC UTILITY COMMISSION OF OREGON

CITIZENS' UTILITY BOARD OF OREGON

INDUSTRIAL CUSTOMERS OF NORTHWEST UTILITIES

THE KROGER CO.

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BEFORE THE PUBLIC UTILITY COMMISSION OF THE STATE OF OREGON

UE 294

PORTLAND GENERAL ELECTRIC COMPANY

Joint Testimony in Support of Second Partial Stipulation

Marianne Gardner
Jamie McGovern
Bradley Mullins
Neal Townsend
Karla Wenzel

August 28, 2015

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I. Introduction

Q. Please state your names and positions.

A. My name is Marianne Gardner. I am a Senior Revenue Requirement Analyst in the Energy Rates, Finance, and Audit Division of the Public Utility Commission of Oregon (OPUC). My qualifications appear in OPUC Staff Exhibit 701.

My name is Jaime McGovern. I am a Senior Economist for the Citizens' Utility Board of Oregon (CUB). My qualifications appear in CUB Exhibit 101.

My name is Bradley G. Mullins. I am independent consultant representing the Industrial Customers of Northwest Utilities ("ICNU"). My qualifications appear in ICNU Exhibit 101.

My name is Neal Townsend. I am a Principal at Energy Strategies, LLC. My testimony is being sponsored by Fred Meyer Stores and Quality Food Centers ("Fred Meyer"), divisions of The Kroger Co. My qualifications appear in FM / 100.

My name is Karla Wenzel. I am Manager of Rates in Portland General Electric's (PGE's) Rates and Regulatory Affairs Department. My qualifications appear in Section XI, below.

Q. What is the purpose of your testimony?

A. The purpose of our testimony is to describe the August 28, 2015 Second Partial Stipulation (Partial Stipulation) reached among the OPUC Staff (Staff); CUB; ICNU; Fred Meyer; and PGE (collectively, the Stipulating Parties) in this docket (UE 294). For convenience, we use the issue numbers assigned in the May 15, 2015 Staff Issues List.

Q. What is the basis for the Partial Stipulation?

A. PGE filed this general rate case on February 12, 2015. Over the following four months, PGE responded to approximately 700 data requests from Staff, CUB, ICNU, and other parties. On May 16, Staff provided an initial analysis of numerous issues and the Stipulating Parties participated in Settlement Conferences on May 21 and May 29, during which other parties also identified issues. Parties also participated in Settlement Conferences on July 8, July 9 and July 17. During those discussions, PGE accepted a number of Staff's proposals and offered modifications regarding others. The Stipulating Parties also accepted a number of PGE's suggestions, which represented compromises that parties deemed reasonable for settlement purposes. As a result, when coupled with the previously filed Partial Stipulation, the parties had reached settlement of all issues in this docket except one power cost issue. That power cost issue related to the length of the maintenance outage for the Port Westward I plant as modeled in PGE's 2016 power cost forecast. A settlement conference was held on August 7, 2015, and the parties settled the one remaining power cost issue. As a result, this Second Partial Stipulation resolves all remaining issues in this docket, and the Stipulating Parties request adoption of this Second Partial Stipulation, along with the previously filed Partial Stipulation.

Q. What issues does the Second Partial Stipulation resolve?

A. The Partial Stipulation represents the settlement of return on equity (ROE), cost of debt, capital structure, several rate spread / rate design issues, marginal generation costs, load forecast, portfolio option programs, the annual Power Cost Adjustment Mechanism (PCAM), two remaining revenue requirement issues, and power costs. A copy of the stipulation is provided as Exhibit 201. Table 1 below summarizes the settled issues.

Q. Does this Partial Stipulation indicate that all parties agree on the calculations or bases employed by other parties to determine each adjustment?

A. No. Although the Stipulating Parties may not necessarily agree on the calculations, assumptions, or bases used to determine each adjustment, we believe the amounts represent a reasonable financial settlement of the respective issues in this docket. The adjustments are in the public interest and are consistent with rates that are fair, just, and reasonable.

Table 1
Stipulated Issues with Approximate Adjustments

Issue No.	Category	Summary Description
S-0	ROE	Reduce the Allowed ROE to 9.6%.
S-3	Cost of Debt	Cost of Debt to be updated to include new long-term debt issued no later than 11/1/2015.
I-4	Marginal Generation Costs	Marginal generation costs to be the sum of marginal capacity costs and weighted marginal energy costs.
I-5	Load Forecast	PGE agrees to work with Staff to address treatment of energy efficiency in the load forecast and to increase Staff's and other parties' understanding of PGE forecast model. PGE also agrees to exclude the price adjustment from residential and non-residential forecasts in this case.
I-6	Marginal Customer Costs	Include more paperless bills in the marginal billing costs.
I-8	Portfolio Option Programs	PGE will audit the costs that should be allocated to the portfolio program and determine if the revenue contributed by the portfolio customers reasonably matches costs incurred in the program. PGE will work with Staff, other interested parties, and the Portfolio Option Committee (POC) to examine the cost allocation methodology and approach. PGE will present its audit findings to Staff and POC by November 2015.
I-10	Smart Meter Opt Out Program	PGE will update charges for non-network residential meter installation and readings. PGE will make other tariff changes that customers opting for a non-network residential meter will not be eligible for time-of-use rates.
CUB	Other Revenue	Increase Other Revenue by $1.5 million.
CUB	Transmission rate spread	Agree to Staff's proposed rate spread of 75% capacity, 25% energy.
CUB	Residential Customer Charge	Agree to increase by $0.50/month.
CUB	PCAM	No change in Schedule 126 deadbands.
CUB	Capital Structure	Parties agree to PGE's 50/50 capital structure proposal.
ICNU	Generation Marginal Costs Study	Agree to ICNU's proposal regarding capitalized energy costs.
ICNU	Load Following Credit	Increase the Schedule 90 load following credit and allocate the costs of this credit in a hybrid manner.
ICNU	Capital Additions	Reduce rate base by $18.7 million.
ICNU	Rate Schedule Issues	Agree to ICNU's proposal regarding changes in

		partial requirements baseline demand.
SBUA	Rate Case Transparency	Concerns over Schedule 32 rate increase.
Group Issues	Power Costs	Reduce power costs by $7.5 million, 2016 planned maintenance for Port Westward I consistent with April 1, 2015 MONET update.

Q. Does the Partial Stipulation resolve all revenue requirement issues in this proceeding?

A. Yes.

Q. How is your testimony organized?

A. Our testimony is organized as follows:

- Cost of Capital (S-0, S-3, CUB-7)
- Marginal Cost of Service (I-4, I-6, ICNU-2, ICNU-3)
- Load forecast (I-5)
- Portfolio Options (I-8)
- Tariff Schedule 300 –Non Network Meter Charges (I-10)
- Revenue Requirement and Power Cost Issues (CUB-3, ICNU-1, PC-1, PC-2, CUB-8, CUB-9, CUB-10, ICNU-7, ICNU-8, ICNU-10)
- PCAM (CUB-6)
- Ratespread and Rate Design (I-1, I-9, CUB-2, CUB-4, CUB-5, ICNU-4, ICNU-5, ICNU-6, Kroger-1, and SBUA)
- Conclusions
- Qualifications

II. Cost of Capital (S-0, S-3, CUB-7)

Q. What was PGE's position on Cost of Capital?

A. In its direct testimony PGE requested a 7.667% cost of capital for the 2016 test year. That cost of capital included a 9.9% authorized ROE, a 5.433% cost of long-term debt and a 50% equity / 50% (“50-50”) debt to equity capital structure.

Q. What positions did other parties take regarding Cost of Capital?

A. Staff proposed a 7.198% cost of capital. That cost of capital included a 9.160% authorized ROE, a 5.235% cost of long-term debt and a 50-50 capital structure.

ICNU proposed a 7.34% cost of capital. That cost of capital included a 9.25% authorized ROE, a 5.43% cost of long-term debt and a 50-50 capital structure.

CUB recommended a 55%-45% debt-to-equity capital structure, or alternatively a 2% reduction in ROE, but did not otherwise make a proposal for ROE or cost of long-term debt.

Q. Were parties able to reach an agreement for a 2016 test year cost of capital?

A. Yes. In the interest of settlement, the Stipulating Parties agreed that revenue requirement should be set using a 9.6% ROE, a 50-50 capital structure, and actual cost of debt including any new issuances priced by PGE by November 1, 2015. Also, PGE agreed to reduce its revenue requirement by $4 million as a general settlement for the revenue requirement issues in this docket, including cost of capital.

III. Marginal Cost of Service (I-4, I-6, ICNU-2, ICNU-3)

Q. What marginal cost of service issues were identified by the parties in this proceeding?

A. Below are the marginal cost of service issues identified by the parties to this proceeding:

- Staff (I-4) proposed that the costs of Port Westward 2 be included as an energy cost for the purpose of integrating wind generation. In opening testimony, PGE proposed to include the cost of the Bonneville Power Administration’s (BPA) Variable Energy

Resource Balancing Service (VERBS) tariff as a capacity cost to integrate wind generation.

- Staff (I-6) proposed an adjustment to the marginal cost of billing based on reduced postage costs due to a greater incidence of paperless billing than projected by PGE in its opening testimony.
- ICNU (ICNU-2) proposed that a more flexible capacity resource such as Port Westward 2 or an LMS 100 be used in determining the marginal generation capacity costs. In its opening testimony, PGE proposed using a lower cost, less flexible capacity resource for estimating the marginal capacity cost of generation.
- ICNU (ICNU-3) proposed that the marginal cost of energy be reduced because of dispatch margins that could accrue to the baseload resource. ICNU also proposed that for the sake of consistency, PGE should include fixed pipeline costs for the capacity resource when calculating the capitalized costs of energy.

Q. What is the basis for Staff classifying wind integration costs as energy?

A. Staff stated the following in their opening testimony: "Staff's position is that any $/kW cost assigned to supplying wind power should be considered as an energy cost."[1]

Q. What is the basis for ICNU's proposal to include Port Westward 2 or an LMS 100 as the marginal generation capacity resource?

A. ICNU states that PGE is unlikely to actually build the capacity resource specified in its marginal generation cost study and that it is more consistent to use a more recently

[1] Staff / 400, Bhattacharya / 3.

constructed resource given that PGE has used the projected costs of Carty as the basis for the marginal energy costs.

Q. How did the Stipulating Parties resolve these issues?

A. In the interest of an overall settlement, the Stipulating Parties agreed to Staff's position for calculating the marginal generation costs, and agreed to use PGE's marginal capacity resource as the basis for marginal capacity costs.

Q. Why does ICNU propose to reduce the marginal energy costs due to dispatch margins?

A. ICNU made this proposal because it performed an analysis of recent historical market energy prices and market clearing heat rates and concluded that the baseload resource PGE used in the marginal cost study would, during certain hours, produce energy at less than market prices. ICNU concluded that this dispatch margin should be used to reduce the calculated marginal energy cost.

Q. How did the Stipulating Parties resolve this issue?

A. In the interest of an overall settlement, the Stipulating Parties agreed to not incorporate ICNU's proposed margin adjustment to the marginal energy costs.

Q. What is the basis for ICNU's proposed adjustment to the capitalized energy costs?

A. ICNU pointed out that for the sake of consistency with the marginal baseload resource, PGE should have included the fixed pipeline costs of the marginal capacity resource when calculating the capital costs that are classified as energy.

Q. How did the Stipulating Parties resolve this issue?

A. The Stipulating Parties agreed with ICNU's proposal.

Q. What is Staff's basis for the adjustment to the marginal cost of billing?

A. Staff used a trend analysis to determine the projected number of customers who enroll in paperless bills for the 2016 test period. This is in contrast to PGE's projection that used 2014 paperless bill enrollment as the basis for the 2016 test period. Staff's adjustment has a minor impact on the marginal costs of billing customers.

Q. How did the Stipulating Parties resolve this issue?

A. The Stipulating Parties agreed to Staff's adjustment.

Q. Is there a revenue requirement impact from this issue?

A. No.

IV. Load Forecast (I-5)

Q. Did any parties raise any issues with regard to PGE's load forecast?

A. Yes. Staff made several recommendations, including:

- Excluding the price adjustment to the non-residential energy forecast for this rate case proceeding.
- Working with PGE to identify alternative methods for addressing energy efficiency in the load forecast.
- Using a set of alternative residential load forecast regression models which incorporate real average price in the regression equations in place of PGE's current price elasticity adjustment approach. The magnitude of the test year forecast and associated adjustment was not specified by Staff.

Q. Did any other party raise any issues with regard to PGE's load forecast?

A. No.

Q. Were the Stipulating Parties able to reach an agreement on how to proceed with PGE's load forecast?

A. Yes. In settlement of all load forecast issues, the Stipulating Parties agreed that:

- PGE will exclude in this rate case the price adjustment in the residential and non-residential load forecast.
- PGE will work with Staff to compile a historical series of achieved energy efficiency with a goal of compiling data at the most reasonable disaggregate level, and will work with Staff to consider alternative forecasting modeling methods that incorporate energy efficiency.
- PGE will work to increase Staff's and other parties' to understanding of PGE's load forecasting model. Staff and interested parties are encouraged to participate in Integrated Resource Planning workshops and meetings pertaining to, or including, load forecasting.
- If in a subsequent docket PGE's load forecast model explicitly includes a price effect, PGE agrees to work with the other interested parties to evaluate models that incorporate a marginal price variable into the base forecast.

V. Portfolio Options (I-8)

Q. What are the Portfolio Option issues identified by parties in this proceeding?

A. Staff questioned PGE's voluntary renewables program (Portfolio Options or the Program) costs and whether the Portfolio Options participants were appropriately bearing the costs of the Program. These Program costs included indirect PGE back office support costs of the program such as customer service, accounting, billing, regulatory, legal, purchasing and contracting, as well as direct costs of acquiring renewable energy certificates (RECs), and program management. Staff expressed concern that the $0.40 per MWh that the Renewable Usage portfolio program customers contribute to the back office support costs of the Program may not reasonably reflect the costs incurred. Staff further questioned whether other nonparticipating customers were subsidizing the Program costs for renewable customers when the intent is for the Program participants to cover the Program costs. A final related issue involved what PGE identified as program development and marketing costs that were allocated to all eligible customers.

Q. What did Staff propose?

A. Staff proposed that PGE conduct a review of its Portfolio Options costs to determine the appropriate contribution by renewable program customers to the program administration; if the amount collected does not reasonably match the costs incurred, Staff proposed that PGE make the appropriate program and tariff changes. Finally, Staff proposed that PGE review this allocation and make necessary adjustments on a periodic basis.

Q. How did the Stipulating Parties resolve Staff's concerns?

A. PGE agreed to conduct an audit of Portfolio Options costs and participating customer contributions to determine if program support costs are reasonably borne by the participating customers. PGE will work with Staff, and other interested parties, as well as the Public Utility Commission's Portfolio Option Committee (POC). PGE will present its results to Staff and the POC by November 2015, and make any appropriate changes. The Stipulating Parties agreed that PGE will perform a similar audit of its Portfolio Option programs every three years going forward and make adjustments when necessary.

VI. Tariff Schedule 300 Non-Network Meter Charges (I-10)

Q. What issues were raised with regard to PGE's non-network meters?

A. Staff raised the issue regarding charges for installing and reading non-network meters for customers opting out of PGE's advanced metering infrastructure system. The concern was that the current charges were too high and may not be cost based. The charges are found in PGE's Schedule 300.

Q. Did any parties request information with regard to PGE's non-network meters?

A. Yes. In OPUC Data Request Nos. 469 – 472, Staff requested the following information regarding PGE's non-network meters:

1. The 2015 cost of a non-network meter.
2. The cost of replacing residential network meters with non-network meters.
3. The number of customers that currently have non-network meters.
4. The number of customers who have inquired about replacing their network meter with a non-network meter.

Q. What is the basis of Staff's inquiry about PGE's non-network meters?

A. Staff commented that their counter-parts at the Consumer Services Section had received customer complaints about PGE's opt-out option. CUB also commented that they, too, had received complaints. The basis of these complaints is the one-time installation and recurring meter reading costs for a customer opting-out.

Q. In updating the costs to respond to Staff's data requests, did the costs change?

A. Yes. Meter reading of non-network meters cost will be updated to $45.00, from the listed tariff charge of $51.00. These costs are based on more recent estimates of travel time, labor, and vehicle expenses. The current cost to install a non-network meter is $254.00, which includes the cost of a meter that is capable of recording and storing customer interval load data so that a customer opting out could still select time-of-use pricing. PGE noted that the installation price could be reduced if the replacement meter did not have to record and store customer interval load data.

Q. How was this issue resolved in settlement?

A. Schedule 300 charges for installing and reading non-network meters will be updated in PGE's compliance tariff filing to $100 from the current $254 for the one-time installation and $45 per month from the current $51 monthly charge for meter reading. The non-network meters will not be capable of recording and storing customer interval load data. Consequently, the Stipulating Parties agreed that PGE will change the tariff so that customers opting for a non-network residential meter will not be eligible for time-of-use rates.

VII. Revenue Requirement and Power Cost Issues (CUB-3, ICNU-1, PC-1, PC-2, CUB-8, CUB-9, CUB-10, ICNU-7, ICNU-8, ICNU-10)

Q. Did the Stipulating Parties resolve all remaining revenue requirement and power cost issues?

A. Yes.

Q. What revenue requirement issues were resolved in this settlement?

A. The settled issues are:

- CUB (CUB-3) concerns regarding under-forecasting of Other Revenues.
- ICNU (ICNU-1) proposed reduction to PGE's rate base pursuant to a review of its capital additions.

Q. Please describe the partial stipulation regarding Other Revenue.

A. CUB performed a detailed evaluation of PGE's actual Other Revenue against budgeted/forecast amounts from 2006 through 2014. Although PGE did not agree with all of the assumptions that CUB used in its analysis, the Stipulating Parties agreed to increase PGE's test year forecast of Other Revenue by $1.5 million.

Q. Please describe the partial stipulation regarding capital additions.

A. ICNU evaluated PGE's capital additions by reviewing documentation supporting the capital projects and by comparing the costs to historical levels of expenditure. Based on additional information provided by PGE, the Stipulating Parties agreed to reduce PGE's rate base by $18.7 million to effectively account for capital projects that were no longer expected to be operational by year-end 2015.

Q. What power cost issues were resolved in this settlement?

A. The settled issues are:

- Staff (PC-1) proposed a collar method be applied to PGE's Coyote Springs plant similar to that used for excluding outliers from coal plants' forced outage rates.
- Staff, CUB, and ICNU (PC-2) proposed to have PGE remove the Super Peak energy purchase from its 2016 power cost forecast.
- CUB (CUB-8) questioned the amount of power cost benefit from Carty in PGE's 2016 forecast based on the plant's projected on-line date.
- CUB (CUB-9) questioned PGE's recovery of the wind forecasting error based on the potential for double counting.
- CUB (CUB-10) questioned whether PGE should analyze using sales for resale to reduce fixed costs by offsetting rate base.

- ICNU (ICNU-7) proposed to reduce PGE's power costs to reflect the economic benefit resulting from access to the California-Oregon Border (COB) market. ICNU based its proposal on the calculated difference between historical Mid-Columbia market prices and COB prices for energy.
- ICNU (ICNU-8) questioned PGE's calculations for the load net wind reserves and proposed that PGE's forecasting model be updated to reflect a change in the reserve formula.
- ICNU (ICNU-10) proposed that PGE's 2016 power cost forecast should include pipeline capacity release credits based on historical credits earned and on the potential for credits due to PGE's gas storage contracts.
- Staff and ICNU recommended denying PGE's request to increase the planned maintenance outage to include in the 2016 power cost forecast for Port Westward I from 20 days to 79 days.

Q. How did the Stipulating Parties resolve these issues?

A. The Stipulating Parties agreed that reducing PGE's power cost forecast by $7.5 million and including in the 2016 power cost forecast the planned maintenance for Port Westward I consistent with the forecast included in PGE's April 1, 2015 MONET update would reasonably address all of these issues.

Q. Did the Stipulating Parties agree to any follow-up conditions for these issues?

A. Yes. The Stipulating Parties agreed to two follow-up conditions. First, we agreed that PGE will propose a method for forecasting California trading margins in its next Annual Power Cost Update filing (i.e., April 1, 2016), under tariff Schedule 125. Second, the Stipulating Parties request that the Commission open a docket to address the forecasting of forced outage rates for natural gas generating plants, specifically, whether there should be limits on the length of historical forced outages included in the four-year rolling average.

VIII. Power Cost Adjustment Mechanism (CUB-6)

Q. Did any parties raise any issues with regard to PGE's Annual PCAM?

A. Yes. CUB proposed updating the PCAM's power cost deadbands because of the increase in PGE's rate base. Specifically, CUB proposed establishing a deadband of $60 million above forecasted costs and $30 million below forecasted cost.

Q. Were the Stipulating Parties able to reach an agreement on how to proceed with PGE's PCAM deadbands?

A. Yes. In the interest of settlement, there will be no change in this docket to the deadbands currently contained in PGE's Annual Power Cost Variance Mechanism tariff, Schedule 126. The settlement in this docket does not prevent CUB or any other party from raising this issue in a subsequent proceeding.

IX. Ratespread and Rate Design (I-1, I-9, CUB-2, CUB-4, CUB-5, ICNU-4, ICNU-5, ICNU-6, SBUA-1)

Q. What are the ratespread, rate design, and tariff issues specified by the parties?

A. Below are the issues:

- Staff (I-1) and CUB (CUB-4) proposed different methods to allocate PGE's transmission revenue requirement.
- Staff (I-1) disagreed with PGE's proposal to price the optional irrigation Schedules 47 and 49 in a manner that will facilitate future consolidation into Schedules 32 and 38,

respectively. PGE's proposal results in higher price increases for Schedules 32 and 38 than would otherwise occur.

- Staff (I-1) proposed to cap the rate increase for Schedules 47 and 49 at 12.5% before inclusion of Carty. ICNU (ICNU-6) proposed to cap the rate increase for the two irrigation schedules at 12% after inclusion of the Carty generating station (Carty). PGE proposed to consolidate Schedule 47 into Schedule 32 and cap the rate increase at 12% for the consolidated Schedules 38 and 49.
- Staff proposed that the burden of mitigating the irrigation schedules rate increase fall on all other customers as opposed to PGE's proposal to spread the mitigation burden of Schedule 49 to Schedules 83 and 85. ICNU supported PGE's proposal to spread the mitigation burden to Schedules 83 and 85.
- Staff (I-1) and CUB (CUB-5) disagreed with PGE's proposal to raise the Schedule 7 monthly Basic Charge from $10.00/month to $11.00/month.
- Staff (I-9) stated a preference that PGE not accelerate the U.S. Department of Energy (DOE) refund.
- CUB (CUB-2) raised concerns regarding the inclusion of the Residential Exchange Credit in determining whether a rate class should contribute to the burden of mitigating the rate increase for the irrigation Schedules 47 and 49.
- ICNU (ICNU-4) expressed concerns about PGE's proposal to allocate the costs of the Schedule 90 load following credit to Schedule 89.
- ICNU (ICNU-5) objected to PGE's proposed changes to a Special Condition contained in Schedule 75/575 Partial Requirements Service. ICNU also proposed that PGE update the reservation payment for Schedule 77 Firm Load Reduction.

- ICNU (ICNU-6) proposed an alternative method of allocating the franchise fee revenue requirement.
- The SBUA (SBUA-1) expressed concerns regarding the price impact on Schedule 32 customers.
- Kroger (Kroger-1) proposed that in its next general rate case, PGE evaluate the costs of maintaining secondary conductors and how that maintenance cost should be allocated.

Q. In what manner do Staff and CUB propose the transmission revenue requirement be allocated to the rate schedules?

A. Staff proposed a revenue requirement allocation that is partially based on the four coincident peaks occurring in January, July, August, and December and partially based on energy. More specifically, Staff proposed that 75% of the allocation be based on the four coincident peaks specified above, and 25% on the basis of energy. CUB proposed an allocation using the same four coincident peaks as Staff, but weighted the coincident peak portion at 65% and the energy portion at 35%. These proportions are the same as those stipulated to in Docket No. UE 262 and used to determine current prices. Staff and CUB's proposals contrast with PGE's proposal to allocate the transmission revenue requirement on the basis of the twelve monthly coincident peaks.

Q. How did the Stipulating Parties resolve this issue?

A. In the interest of settlement, the Stipulating Parties agreed on Staff's proposed allocation.

Q. Why does Staff oppose PGE's proposal to price the irrigation Schedules 47 and 49 in a manner that will eventually lead to a consolidation into Schedules 32 and 38?

A. Staff opposed the consolidation of these schedules because of their significant cost differences. In Staff's opinion, these cost differences justify keeping the customers on their respective schedules. Staff is convinced that PGE's proposal is unfair to Schedule 32 and 38 customers and that this inequity outweighs any cost savings that will occur from eventual rate consolidation.

Q. How did the Stipulating Parties resolve this issue?

A. The Stipulating Parties agreed that PGE will not price the affected schedules in a manner that presumes consolidation, but rather that Schedule 38 will be priced at its cost of service, and Schedules 47 and 49 will have their price impacts mitigated by the Customer Impact Offset (CIO), which is discussed below.

Q. What did the Stipulating Parties agree to regarding the level of the CIO and who will bear the burden of mitigating the price increase for the irrigation Schedules 47 and 49?

A. The Stipulating Parties agreed that the rate increase cap for Schedules 47 and 49 will be set at the greater of 13.5%, or three times the overall base rate increase, excluding supplemental schedules, after inclusion of Carty. The Stipulating Parties further agreed that Schedule 32 will bear the burden of mitigating the Schedule 47 price increase and that both Schedules 83 and 85 will bear the burden of mitigating the Schedule 49 price increase. This resolution reduces the rate increase burden on Schedule 32, relative to PGE's original proposal of consolidating Schedules 32 and 47. The resolution also acknowledges that, but for the existence of optional Schedule 49, the customers on this schedule would be served on standard service Schedules 83 and 85 where they would incur higher monthly bills.

Q. What did Staff and CUB propose with regard to PGE's proposal to raise the Schedule 7 Basic Charge?

A. Staff acknowledged that PGE's marginal customer costs exceed the proposed $11.00/month basic charge, but expressed a preference for a more modest increase to $10.50/month. Staff also stated that their recommendation of $10.50/month is contingent on Schedule 7 volumetric prices not decreasing below current volumetric prices as a result of the increase in the basic charge. CUB proposed no change in the current basic charge of $10.00/month.

Q. How did the Stipulating Parties resolve this issue?

A. For the purposes of settlement, the Stipulating Parties agreed to a $10.50/month basis charge. Because the volumetric charges for Carty will result in an increase in the overall Schedule 7 volumetric charges, there is no need for Staff's proposed contingency.

Q. Why is Staff opposed to PGE's proposal to accelerate the DOE refund?

A. Staff is concerned about the rate impacts that will occur January 2017 when the accelerated amortization of the refund is complete. Staff prefers that PGE amortize the credits over three years (2015-2017) as originally proposed in UE 283 rather than accelerate the amortization such that the credits will conclude at the end of 2016.

Q. How did the Stipulating Parties resolve this issue?

A. The Stipulating Parties agreed that PGE will amortize the credits over the 2015-2017 period, but with modifications. The first modification is that PGE will file to set the Schedule 143 prices to zero effective January 1, 2016. Even with this change, the overall price changes effective January 1, 2016 will result in an overall decrease. The second modification is that PGE will file to set Schedule 143 prices to refund over the rest of 2016 the amount that would have otherwise been amortized over calendar year 2016 if the above change had not happened at approximately the same time when PGE includes Carty in rates, currently expected to be mid-May 2016. This timing change in amortization of the DOE refund results in a greater annualized amortization, helping to smooth the Carty-related rate impacts. Finally, in 2017, PGE will file to set Schedule 143 to amortize the remaining balance of the DOE credits over calendar year 2017. The result of all these timing changes in the DOE amortization is that the overall rate impacts occurring January 1, 2016, mid-May 2016, and January 2017 are spread in a more level manner to reduce rate impacts.

Q. What is the nature of CUB's concern regarding the Residential Exchange Credit and how was their concern resolved?

A. Because the Residential Exchange Credit was included in the pricing exhibits and tables, CUB expressed concern that the Residential Exchange Credit might be taken into account when determining who should bear the CIO surcharge burdens. The Stipulating Parties agreed that it would be inappropriate to include the Residential Exchange Credit in determining who should contribute to mitigating the rate increase for the irrigation schedules.

Q. Why did ICNU object to PGE's proposal to spread the costs of the Schedule 90 load following credit to Schedule 89?

A. ICNU believes that PGE's proposal is inequitable to Schedule 89 and that the cost of the load following credit should be allocated to all cost-of-service (COS) customers, as was done in UE 262 and UE 283.

Q. How was this issue resolved?

A. The Stipulating Parties agreed that a portion of the load following credit equal to the amount in current prices ($1.13/MWh for 150 average megawatts) should be allocated to all COS customers. In the interest of equalizing the price impacts for Schedule 89 Primary Voltage and Schedule 90 Primary Voltage customers, the Stipulating Parties agreed that the load following credit should be increased to $2.00/MWh, with the cost of the increment ($0.87/MWh) above that contained in current rates allocated to Schedule 89 COS customers.

The Stipulating Parties further agreed that in its next general rate case, PGE will examine the costs associated with load following through its marginal cost of service study.

Q. What did ICNU propose with regard to PGE's proposed changes to the Special Conditions of Schedules 75/575? In addition, what did ICNU propose regarding Schedule 77 Firm Load Reduction?

A. ICNU proposed to modify PGE's proposed change to a Schedule 75 (and Schedule 575) Special Condition such that PGE will be required to provide notice to a partial requirements customer before proposing a change in their baseline demand. ICNU also proposed to increase the reservation payments made to customers who participate in Schedule 77.

Q. How did the Stipulating Parties resolve these issues?

A. PGE agreed to the ICNU modifications to PGE's proposed changes in the applicable Special Conditions of Schedules 75 and 575. In the interest of settlement, ICNU agreed to not pursue its proposed changes to the Schedule 77 reservation payments.

Q. What did ICNU propose regarding the allocation of franchise fees and how was this issue resolved?

A. ICNU proposed allocating franchise fees on the basis of the functionalized distribution and transmission revenue requirements rather than the method proposed by PGE, which in addition to the distribution and transmission revenue requirements, included generation and customer service revenue requirements. In the interest of settlement, ICNU agreed to not pursue this issue.

Q. What concerns does the SBUA express regarding the price impacts to Schedule 32 and how were these issues resolved?

A. The SBUA expressed a concern that the rate impacts for Schedule 32 were higher than the overall average. Because the Stipulating Parties agreed to not consolidate Schedule 47 with Schedule 32, the rate impact for Schedule 32 was lessened relative to PGE's original proposal and PGE will work to help SBUA understand rate impacts for its customer class.

Q. Do the Stipulating Parties agree with Kroger that in its next general rate case, PGE should explicitly evaluate the maintenance costs of secondary voltage conductors and the applicability of these maintenance costs to the rate schedules and delivery voltages?

A. Yes, the Stipulating Parties agreed that PGE should do so in its next general rate case. This evaluation will improve PGE's marginal cost estimates and provide for an improved allocation of costs to the rate schedules and delivery voltages.

X. Conclusions

Q. Has PGE updated its revenue requirement and calculated the rate impacts based on this stipulation?

A. Yes. Table 2, below, summarizes the revenue requirement impacts of this stipulation plus the impact of the first partial stipulation and all other updates to power costs and the load forecast. It also includes the rate base reduction from the sale of poles and circuit to the City of Portland (based on assumed Commission approval in Docket No. UP 310). Exhibits 202 through 205 summarize the rate impacts by tariff schedule as of this filing as follows:

- Exhibit 202 – PGE Base Business as of January 1, 2016.
- Exhibit 203 – PGE Base Business and Supplemental Schedules as of January 1, 2016.
- Exhibit 204 – PGE Base Business with Carty.
- Exhibit 205 – PGE Base Business with Carty and Supplemental Schedules.

Table 2
Revenue Requirement Impacts
($Millions)

	As Filed February 12, 2015	**Stipulations and Updates through July 15, 2015**	**August 2015 Stipulations and Updates**	**As Revised August 28, 2015***
Base Business	$38.8	$(20.9)	$(28.2)	$(10.3)
Carty	$83.6	$1.1	$(1.4)	83.3
Supplemental Schedules	$(56.2)	$(5.7)	$6.7	$(55.2)
Total Revenue Requirements, Net*	**$66.2**	**$(25.5)**	**$(22.8)**	**$17.8**

* May not sum due to rounding

Q. Will PGE have any additional updates to this proceeding?

A. Yes. Prior to the end of this proceeding, PGE will provide the following updates:

- Load forecast to be finalized in October 2015;

- Power cost forecast to be finalized on November 16, 2015; and
- Actual cost of debt, including any new issuances, to be finalized no later than November 1, 2015.

XI. Qualifications

Q. Ms. Wenzel, please state your qualifications.

A. I received a Bachelor of Arts degree from Willamette University in 1983 and my Juris Doctor degree from Lewis and Clark's Northwestern College of Law in 1991. In addition, I have taken postgraduate courses in utility management, negotiation, and accounting. I joined Portland General Electric Company in 1989 and have held various positions in Legal, Distribution, Customer Service, and Rates and Regulatory Affairs. My current role is the Manager of Pricing and Tariffs.

Q. Does this conclude your testimony?

A. Yes.

List of Exhibits

Joint Party Exhibit	**Description**
201	Copy of Second Partial Stipulation
202	Rate Impacts – PGE Base Business as of January 1, 2016
203	Rate Impacts – PGE Base Business and Supplemental Schedules as of January 1, 2016
204	Rate Impacts – PGE Base Business with Carty
205	Rate Impacts – PGE Base Business with Carty and Supplemental Schedules

BEFORE THE PUBLIC UTILITY COMMISSION OF OREGON

UE 294

In the Matter of PORTLAND GENERAL ELECTRIC COMPANY Request for a General Rate Revision.	**SECOND PARTIAL STIPULATION**

This Partial Stipulation ("Stipulation") is between Portland General Electric Company ("PGE"), Staff of the Public Utility Commission of Oregon ("Staff"), the Citizens' Utility Board of Oregon ("CUB"), the Industrial Customers of Northwest Utilities ("ICNU"), and Fred Meyer Stores and Quality Food Centers, Division of The Kroger Co. ("Kroger") (collectively, the "Stipulating Parties"). The Small Business Utility Advocates also participated in settlement discussions and does not oppose this Stipulation. No other parties participated in the settlement discussions.

On June 23, 2015, a Partial Stipulation resolving a number of revenue requirement issues was filed in this docket. Since that time the Stipulating Parties have held numerous settlement conferences to address issues raised in the testimony filed in this docket. All power cost issues except one, and all revenue requirement issues, were settled on July 8 and 9, 2015, subject to satisfactory settlement of rate spread and rate design issues. On July 17, 2015, the parties settled all rate spread and rate design issues. As a result, when coupled with the previously filed Partial Stipulation, the parties had reached settlement of all issues in this docket except one power cost issue. That power cost issue related to the length of the maintenance outage for the Port

Westward I plant as modeled in PGE's 2016 power cost forecast. A settlement conference was held on August 7, 2015, and the parties settled the one remaining power cost issue. As a result, this Second Partial Stipulation resolves all remaining issues in this docket, and the Stipulating Parties request adoption of this Second Partial Stipulation, along with the previously filed Partial Stipulation.

TERMS OF SECOND PARTIAL STIPULATION

1. This Partial Stipulation resolves the issues identified below.

   a. Load Forecast (I-5). In settlement of all load forecast issues, the Stipulating Parties agree:

      i. PGE will exclude in this rate case the price adjustment in the residential and non-residential load forecast.

      ii. PGE will work with Staff to compile a historical series of achieved energy efficiency with a goal of compiling data at the most reasonable disaggregate level, and will work with Staff to consider alternative forecasting modeling methods that incorporate energy efficiency.

      iii. PGE will work with Staff and other parties to understand PGE's load forecasting model. Staff and interested parties are also encouraged to participate in IRP workshops and meetings pertaining to or including load forecasting.

      iv. If in a subsequent docket PGE's load forecast explicitly accounts for a price effect, PGE agrees to work with the other interested parties to evaluate models that incorporate a marginal price variable into the base forecast.

b. Portfolio Options (I-8). To settle issues regarding cost allocation for renewable portfolio options, the parties agree that:

   i. PGE will audit the costs allocated to the voluntary portfolio options programs and customers, and work with Staff and interested parties, including the Portfolio Options Committee, to examine the cost allocation methodology and approach. This will be done and reviewed with Staff and the Portfolio Options Committee by November 2015. PGE will follow up on audit results with any necessary tariff filing.

   ii. Every three years after this audit, or more frequently if requested by Staff or another Stipulating Party, the allocation of costs to these portfolio options will be examined in the same manner.

c. Tariff Schedule 300 (I-10). Charges for Non-Network Residential Meter Rates will be set at: Installation of non-network meter: $100

   Non-network Meter Read: $45 per month.

   The parties further agree that PGE should make other tariff changes necessary such that customers opting for a non-network residential meter are not eligible for time-of-use rates.

d. Rate base (ICNU -1). To resolve all rate base issues raised by all parties, PGE's test-year rate base will be reduced by $18.7 million. The rate base reductions in this Stipulation and the Partial Stipulation do not incorporate the effects of Docket No. UP 310; rate base will be further reduced in the event the Commission approves the sale of poles to the City of Portland in that docket.

e. Other revenues (CUB-3). The test-year forecast of Other Revenues will be increased by $1.5 million.

f. Power costs (PC-1, PC-2, CUB-8, CUB-9, CUB-10, ICNU-7, ICNU-8, ICNU-10). In settlement of remaining power cost issues, test-year power costs will be reduced by $7.5 million. Planned maintenance for Port Westward I included in the 2016 power cost forecast will be consistent with the forecast included in PGE's April 1, 2015, MONET update. This settles all other power cost issues including California trading margins, the 2016 forced outage rate for Coyote Springs, the Super Peak Energy Purchase, load net of wind reserves, pipeline capacity release credits, the Carty modeled online date, and all other power cost issues raised in this docket. In addition to the $7.5 million reduction in power costs:

   i. PGE will propose a method for forecasting California trading margins in its next Annual Power Cost Update filing (i.e., April 1, 2016), under tariff Schedule 125.

   ii. The parties request that the Commission open a docket to address the forecasting of forced outage rates for natural gas generating plants, specifically whether there should be limits on the length of historical forced outages included in the four-year rolling average.

g. Cost of Capital (S-0, S-3, CUB-7). Revenue requirement should be set using a 9.6% return on equity, and a 50% equity, 50% debt capital structure. In settlement of cost of capital and all other issues in this docket, PGE's revenue requirement will be reduced by $4 million. Cost of debt will be updated later this year to incorporate actual 2015 debt costs, including any new issuances priced by PGE, no later than November 1, 2015. PGE will base the cost of debt update on Exhibit Staff/207C, including all updates to that document provided by Staff in July 2015 and any additional bond issuance detail for 2015. Accordingly, the revenue requirement impact of this stipulation may change.

h. PCAM (CUB-6). There will be no change in this docket to the deadbands currently contained in PGE's Annual Power Cost Variance Mechanism (PCAM) tariff, Schedule 126.

i. Marginal Cost (I-4, I-6, ICNU-2, ICNU-3). In settlement of all marginal cost issues the parties agree that in this docket:

   i. The cost of Port Westward 2 will be included as an energy cost for purposes of integrating wind energy.

   ii. The marginal cost of billing will be reduced to account for paperless billing as proposed in Staff's testimony.

   iii. Marginal capacity costs will be calculated as proposed by PGE.

   iv. Fixed pipeline costs of the marginal resource used in the marginal cost study will be included when calculating capitalized energy costs, as proposed by ICNU.

   v. All other elements of the marginal cost calculation will be consistent with the methodology presented in PGE's initial filing.

j. Ratespread and Rate Design. All ratespread and rate design issues are settled as follows:

i. Transmission revenue requirement (Staff I-1, CUB-4). Transmission revenue requirement will be allocated 25% based on energy, and 75% based on coincident peaks in the months of January, July, August, and December.

ii. Schedule Consolidation and Customer Impact Offset (Staff I-1). As part of this settlement, tariff Schedules 47 and 49 will not be priced in a manner that presumes future consolidation with Schedules 32 and 38 respectively. Schedules 38 will be priced at cost-of-service. The rate increase in this docket for Schedules 47 and 49 will be set at the greater of 13.5% or three times the overall base rate increase, excluding supplemental schedules, after inclusion of the Carty plant. Schedule 32 will bear the burden of mitigating the Schedule 47 price increase, and Schedules 83 and 85 will bear the burden of mitigating the Schedule 49 price increase.

iii. Schedule 7 Basic Charge (Staff I-1, CUB-5). The Basic Charge for Schedule 7 customers will be set at $10.50.

iv. Schedule 143 (Staff I-9). Amortization of the refund from the Trojan Nuclear Decommissioning Trust Fund under Schedule 143 will be modified as follows: Beginning January 1, 2016, Schedule 143 prices will be set to zero. Starting at the same time as the Carty plant is included in rates, Schedule 143 prices will be set to refund over the remainder of 2016 the amount that otherwise would have been amortized over 2016 if the change above had not been implemented. Beginning January 1, 2017, Schedule 143 prices will be set to amortize the remaining balance of the refund over calendar year 2017.

v. Load Following Credit (ICNU-4). The Schedule 90 load following credit will be increased in this docket from the current $1.13/MWh to $2.00/MWh. The portion of the credit in current rates ($1.13/MWh for 150 average megawatts) will be allocated to all customers. The increased amount ($0.87/MWh) will be allocated to Schedule 89 customers. In its next general rate case, PGE agrees to complete a study to evaluate the marginal cost of load following and other related ancillary services.

vi. Schedules 75 and 575 (ICNU-5). The Special Conditions in Schedules 75 and 575 will be modified as proposed by ICNU to require notice by PGE to partial requirements customers before PGE proposes a change to their baseline demand.

vii. Franchise Fees (ICNU-6). Franchise fee expenses will be allocated as originally proposed by PGE in this docket.

viii. Maintenance expenses (Kroger-1). Prior to its next rate case, PGE will evaluate the maintenance costs of secondary voltage conductors and the applicability of those costs to specific rate schedules and delivery voltages.

2. All other issues raised in this docket not otherwise specifically addressed above have been settled with no adjustments.

3. The Stipulating Parties recommend and request that the Commission approve the

adjustments and provisions described herein as appropriate and reasonable resolutions of the identified issues in this docket.

4. The Stipulating Parties agree that this Stipulation is in the public interest, and will contribute to rates that are fair, just and reasonable, consistent with the standard in ORS 756.040.

5. The Stipulating Parties agree that this Stipulation represents a compromise in the positions of the Stipulating Parties. Without the written consent of all of the Stipulating Parties, evidence of conduct or statements, including but not limited to term sheets or other documents created solely for use in settlement conferences in this docket, are confidential and not admissible in the instant or any subsequent proceeding, unless independently discoverable or offered for other purposes allowed under ORS 40.190.

6. The Stipulating Parties have negotiated this Stipulation as an integrated document. The Stipulating Parties, after consultation, may seek to obtain Commission approval of this Stipulation prior to evidentiary hearings. If the Commission rejects all or any material part of this Stipulation, or adds any material condition to any final order that is not consistent with this Stipulation, each Stipulating Party reserves its right: (i) to withdraw from the Stipulation, upon written notice to the Commission and the other Parties within five (5) business days of service of the final order that rejects this Stipulation, in whole or material part, or adds such material condition; (ii) pursuant to OAR 860-001-0350(9), to present evidence and argument on the record in support of the Stipulation, including the right to cross-examine witnesses, introduce evidence as deemed appropriate to respond fully to issues presented, and raise issues that are incorporated in the settlements embodied in this Stipulation; and (iii) pursuant to ORS 756.561 and OAR 860-001-0720,

to seek rehearing or reconsideration, or pursuant to ORS 756.610 to appeal the Commission's final order.

7. This Stipulation will be offered into the record in this proceeding as evidence pursuant to OAR 860-001-0350(7). The Parties agree to support this Stipulation throughout this proceeding and in any appeal, and provide witnesses to support this Stipulation (if specifically required by the Commission), and recommend that the Commission issue an order adopting the settlements contained herein. By entering into this Stipulation, no Stipulating Party shall be deemed to have approved, admitted or consented to the facts, principles, methods or theories employed by any other Stipulating Party in arriving at the terms of this Stipulation. Except as provided in this Stipulation, no Stipulating Party shall be deemed to have agreed that any provision of this Stipulation is appropriate for resolving issues in any other proceeding.

8. This Stipulation may be signed in any number of counterparts, each of which will be an original for all purposes, but all of which taken together will constitute one and the same agreement.

DATED this 28th day of August, 2015.

PORTLAND GENERAL ELECTRIC COMPANY

STAFF OF THE PUBLIC UTILITY COMMISSION OF OREGON

CITIZENS' UTILITY BOARD OF OREGON

INDUSTRIAL CUSTOMERS OF NORTHWEST UTILITIES

THE KROGER CO.

TABLE 1
PORTLAND GENERAL ELECTRIC
ESTIMATED EFFECT ON CONSUMERS' TOTAL ELECTRIC BILLS
2016

CATEGORY	RATE SCHEDULE	CUSTOMERS (Forecast SJUN15E16)	MWH SALES	TOTAL ELECTRIC BILLS CURRENT w/ Sch. 122a, 125	TOTAL ELECTRIC BILLS PROPOSED w/ Sch. 125	Change AMOUNT	Change PCT.
Residential	7	747,798	7,580,508	$908,785,442	$910,693,578	$1,908,136	0.2%
Employee Discount				($958,757)	($958,844)	($87)	
Subtotal				$907,826,685	$909,734,735	$1,908,049	0.2%
Outdoor Area Lighting	15	0	16,536	$3,634,838	$3,464,379	($170,458)	-4.7%
General Service <30 kW	32	90,067	1,582,608	$173,288,717	$175,256,700	$1,967,983	1.1%
Opt. Time-of-Day G.S. >30 kW	38	500	38,323	$5,156,008	$5,134,164	($21,844)	-0.4%
Irrig. & Drain. Pump. < 30 kW	47	3,164	20,595	$3,653,733	$4,035,574	$381,840	10.5%
Irrig. & Drain. Pump. > 30 kW	49	1,337	63,710	$7,914,041	$8,640,333	$726,292	9.2%
General Service 31-200 kW	83	11,103	2,847,977	$255,040,185	$253,928,377	($1,111,808)	-0.4%
General Service 201-4,000 kW							
Secondary	85-S	1,280	2,466,885	$194,333,348	$191,152,401	($3,180,947)	-1.6%
Primary	85-P	192	761,452	$56,385,467	$55,411,721	($973,746)	-1.7%
Schedule 89 > 4 MW							
Primary	89-P	16	777,633	$51,220,420	$49,552,014	($1,668,406)	-3.3%
Subtransmission	89-T	5	81,168	$6,905,737	$6,254,854	($650,883)	-9.4%
Schedule 90	90-P	4	1,508,946	$92,296,593	$89,122,613	($3,173,980)	-3.4%
Street & Highway Lighting	91/95	205	68,786	$13,398,757	$12,843,049	($555,708)	-4.1%
Traffic Signals	92	17	3,243	$250,707	$251,907	$1,200	0.5%
COS TOTALS		855,688	17,818,370	$1,771,305,237	$1,764,782,820	($6,522,417)	-0.4%
Direct Access Service 201-4,000 kW							
Secondary	485-S	155	422,059	$8,665,620	$8,015,275	($650,345)	
Primary	485-P	44	275,564	$5,807,561	$5,492,399	($315,162)	
Direct Access Service > 4 MW							
Secondary	489-S	1	14,559	$453,010	$328,395	($124,615)	
Primary	489-P	9	537,819	$6,922,601	$4,660,967	($2,261,634)	
Subtransmission	489-T	3	324,687	$3,138,051	$2,603,562	($534,489)	
DIRECT ACCESS TOTALS		212	1,574,687	$24,986,844	$21,100,599	($3,886,245)	
COS AND DA CYCLE TOTALS		855,900	19,393,057	$1,796,292,082	$1,785,883,420	($10,408,662)	-0.6%

TABLE 4
PORTLAND GENERAL ELECTRIC
ESTIMATED EFFECT ON CONSUMERS' TOTAL ELECTRIC BILLS
2016

CATEGORY	RATE SCHEDULE	Forecast SJUN15E16 CUSTOMERS	MWH SALES	TOTAL ELECTRIC BILLS CURRENT with all supplementals except LIA & PPC	TOTAL ELECTRIC BILLS PROPOSED with all supplementals except LIA & PPC	Change AMOUNT	Change PCT.
Residential	7	747,798	7,580,508	$888,403,089	$868,024,659	($20,378,430)	-2.3%
Employee Discount				($915,216)	($894,104)	$21,112	
Subtotal				$887,487,873	$867,130,555	($20,357,318)	-2.3%
Outdoor Area Lighting	15	0	16,536	$3,735,910	$3,538,820	($197,091)	-5.3%
General Service <30 kW	32	90,067	1,582,608	$176,598,397	$177,394,180	$795,783	0.5%
Opt. Time-of-Day G.S. >30 kW	38	500	38,323	$5,341,702	$5,284,319	($57,383)	-1.1%
Irrig. & Drain. Pump. < 30 kW	47	3,164	20,595	$3,644,234	$3,970,980	$326,746	9.0%
Irrig. & Drain. Pump. > 30 kW	49	1,337	63,710	$7,809,165	$8,384,031	$574,866	7.4%
General Service 31-200 kW	83	11,103	2,847,977	$264,029,007	$260,402,400	($3,626,607)	-1.4%
General Service 201-4,000 kW							
Secondary	85-S	1,280	2,466,885	$201,768,534	$196,871,807	($4,896,728)	-2.4%
Primary	85-P	192	761,452	$57,852,790	$56,563,424	($1,289,366)	-2.2%
Schedule 89 > 4 MW							
Primary	89-P	16	777,633	$51,593,684	$49,933,054	($1,660,630)	-3.2%
Subtransmission	89-T	5	81,168	$6,945,509	$6,294,626	($650,883)	-9.4%
Schedule 90	90-P	4	1,508,946	$93,035,977	$89,877,086	($3,158,891)	-3.4%
Street & Highway Lighting	91/95	205	68,786	$13,862,376	$13,227,564	($634,812)	-4.6%
Traffic Signals	92	17	3,243	$261,603	$260,403	($1,200)	-0.5%
COS TOTALS		855,688	17,818,370	$1,773,966,761	$1,739,133,248	($34,833,514)	-2.0%
Direct Access Service 201-4,000 kW							
Secondary	485-S	155	422,059	$8,932,570	$8,668,784	($263,786)	
Primary	485-P	44	275,564	$5,824,557	$5,764,406	($60,151)	
Direct Access Service > 4 MW							
Secondary	489-S	1	14,559	$439,325	$329,414	($109,910)	
Primary	489-P	9	537,819	$6,433,186	$4,698,614	($1,734,571)	
Subtransmission	489-T	3	324,687	$2,849,080	$2,626,290	($222,790)	
DIRECT ACCESS TOTALS		212	1,574,687	$24,478,718	$22,087,510	($2,391,209)	
COS AND DA CYCLE TOTALS		855,900	19,393,057	$1,798,445,480	$1,761,220,758	($37,224,722)	-2.1%

TABLE 5 BASE
PORTLAND GENERAL ELECTRIC
ESTIMATED EFFECT ON CONSUMERS' TOTAL ELECTRIC BILLS INCLUDING CARTY
2016

CATEGORY	RATE SCHEDULE	Forecast SJUN15E16 CUSTOMERS	MWH SALES	TOTAL ELECTRIC BILLS CURRENT w/ Sch. 122a, 125	TOTAL ELECTRIC BILLS PROPOSED w/ Sch. 125	Change AMOUNT	Change PCT.
Residential	7	747,798	7,580,508	$908,785,442	$948,596,119	$39,810,677	4.4%
Employee Discount				($958,757)	($999,395)	($40,638)	
Subtotal				$907,826,685	$947,596,724	$39,770,039	4.4%
Outdoor Area Lighting	15	0	16,536	$3,634,838	$3,530,523	($104,314)	-2.9%
General Service <30 kW	32	90,067	1,582,608	$173,288,717	$182,615,825	$9,327,108	5.4%
Opt. Time-of-Day G.S. >30 kW	38	500	38,323	$5,156,008	$5,299,721	$143,713	2.8%
Irrig. & Drain. Pump. < 30 kW	47	3,164	20,595	$3,653,733	$4,146,995	$493,262	13.5%
Irrig. & Drain. Pump. > 30 kW	49	1,337	63,710	$7,914,041	$8,982,454	$1,068,414	13.5%
General Service 31-200 kW	83	11,103	2,847,977	$255,040,185	$266,943,632	$11,903,447	4.7%
General Service 201-4,000 kW							
Secondary	85-S	1,280	2,466,685	$194,333,348	$202,154,708	$7,821,359	4.0%
Primary	85-P	192	761,452	$56,385,467	$58,724,035	$2,338,568	4.1%
Schedule 89 > 4 MW							
Primary	89-P	16	777,633	$51,220,420	$52,833,625	$1,613,205	3.1%
Subtransmission	89-T	5	81,168	$6,905,737	$6,596,571	($309,166)	-4.5%
Schedule 90	90-P	4	1,508,946	$92,296,593	$95,098,040	$2,801,446	3.0%
Street & Highway Lighting	91/95	205	68,786	$13,398,757	$13,118,194	($280,564)	-2.1%
Traffic Signals	92	17	3,243	$250,707	$265,138	$14,431	5.8%
COS TOTALS		855,688	17,818,370	$1,771,305,237	$1,847,906,186	$76,600,948	4.3%
Direct Access Service 201-4,000 kW							
Secondary	485-S	155	422,059	$8,665,620	$8,033,566	($632,054)	
Primary	485-P	44	275,564	$5,807,561	$5,644,450	($163,112)	
Direct Access Service > 4 MW							
Secondary	489-S	1	14,559	$453,010	$328,250	($124,760)	
Primary	489-P	9	537,819	$6,922,601	$4,655,589	($2,267,012)	
Subtransmission	489-T	3	324,687	$3,138,051	$2,600,315	($537,736)	
DIRECT ACCESS TOTALS		212	1,574,687	$24,986,844	$21,262,170	($3,724,674)	
COS AND DA CYCLE TOTALS		855,900	19,393,057	$1,796,292,082	$1,869,168,355	$72,876,274	4.1%

TABLE 5
PORTLAND GENERAL ELECTRIC
ESTIMATED EFFECT ON CONSUMERS' TOTAL ELECTRIC BILLS INCLUDING CARTY
2016

CATEGORY	RATE SCHEDULE	Forecast SJUN15E16 CUSTOMERS	MWH SALES	TOTAL ELECTRIC BILLS CURRENT with all supplementals except LIA & PPC	TOTAL ELECTRIC BILLS PROPOSED with all supplementals except LIA & PPC	Change AMOUNT	Change PCT.
Residential	7	747,798	7,580,508	$888,403,089	$894,025,802	$5,622,713	0.6%
Employee Discount				($915,216)	($921,922)	($6,706)	
Subtotal				$887,487,873	$893,103,879	$5,616,007	0.6%
Outdoor Area Lighting	15	0	16,536	$3,735,910	$3,584,128	($151,782)	-4.1%
General Service <30 kW	32	90,067	1,582,608	$176,598,397	$182,426,872	$5,828,475	3.3%
Opt. Time-of-Day G.S. >30 kW	38	500	38,323	$5,341,702	$5,397,756	$56,054	1.0%
Irrig. & Drain. Pump. < 30 kW	47	3,164	20,595	$3,644,234	$4,047,183	$402,949	11.1%
Irrig. & Drain. Pump. > 30 kW	49	1,337	63,710	$7,809,165	$8,618,483	$809,318	10.4%
General Service 31-200 kW	83	11,103	2,847,977	$264,029,007	$269,316,568	$5,287,560	2.0%
General Service 201-4,000 kW							
Secondary	85-S	1,280	2,466,885	$201,768,534	$204,395,806	$2,627,271	1.3%
Primary	85-P	192	761,452	$57,852,790	$58,832,550	$979,760	1.7%
Schedule 89 > 4 MW							
Primary	89-P	16	777,633	$51,593,684	$52,180,413	$586,729	1.1%
Subtransmission	89-T	5	81,168	$6,945,509	$6,530,013	($415,496)	-6.0%
Schedule 90	90-P	4	1,508,946	$93,035,977	$93,966,330	$930,353	1.0%
Street & Highway Lighting	91/95	205	68,786	$13,862,376	$13,416,038	($446,338)	-3.2%
Traffic Signals	92	17	3,243	$261,603	$269,451	$7,848	3.0%
COS TOTALS		855,688	17,818,370	$1,773,966,761	$1,796,085,471	$22,118,709	1.2%
Direct Access Service 201-4,000 kW							
Secondary	485-S	155	422,059	$8,932,570	$8,091,972	($840,598)	
Primary	485-P	44	275,564	$5,824,557	$5,538,934	($285,623)	
Direct Access Service > 4 MW							
Secondary	489-S	1	14,559	$439,325	$309,323	($130,001)	
Primary	489-P	9	537,819	$6,433,186	$3,977,938	($2,455,248)	
Subtransmission	489-T	3	324,687	$2,849,080	$2,197,704	($651,377)	
DIRECT ACCESS TOTALS		212	1,574,687	$24,478,718	$20,115,870	($4,362,848)	
COS AND DA CYCLE TOTALS		855,900	19,393,057	$1,798,445,480	$1,816,201,341	$17,755,861	1.0%