ORDER NO. 14 422

ENTERED: DEC 04 2014

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 283

In the Matter of PORTLAND GENERAL ELECTRIC COMPANY, Request for a General Rate Revision.	ORDER

DISPOSITION: STIPULATIONS ADOPTED; APPLICATION FOR GENERAL RATE REVISION APPROVED AS REVISED

I. SUMMARY

Portland General Electric Company seeks a 4.6 percent increase in rates to produce \$81.5 million in additional revenues.[1] In this order, we adopt proposed settlements to resolve all issues related to the request and authorize an overall rate increase of 2.56 percent, or \$44.33 million in additional revenues. Effective January 1, 2015, bills will increase on average by three percent for residential customers and 2.6 percent for commercial and industrial customers.[2]

II. BACKGROUND AND PROCEDURAL HISTORY

PGE is a public utility providing electricity service within the meaning of ORS 757.005, and is subject to our jurisdiction with respect to the prices and terms of service for its Oregon retail customers.

On February 13, 2014, PGE filed Advice No. 14-03 to increase overall rates by 4.6 percent to produce additional revenues of \$81.5 million. PGE seeks the increase to recover increased business expenses and costs associated with the addition of the Port Westward 2 (PW2) and the Tucannon River Wind Farm (Tucannon) generating plants.

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[1] PGE's filing also included a request to recover additional net variable power costs (NVPC). By ruling of March 11, 2014, all NVPC issues were resolved in a separate docket, UE 286. *See* Order No. 14-318, as corrected by Order No. 14-355.

[2] These amounts reflect the changes to PGE's NVPCs adopted in Docket No. UE 286, as well as PGE's subsequent final MONET update that reduced its forecast 2015 NVPC by \$17.7 million. *See* (UE 283, PGE/500, Niman-Peschka-Hager/1). We take Official Notice of PGE's final MONET Update, and admit into the record PGE's Final Revenue Requirement and Pricing Update, attached as Appendix D, reflecting the impact of the NVPC updates.

On February 18, 2014, we suspended PGE's tariff filing for a period of nine months as authorized by ORS 757.215.[3] During the course of the proceedings, the following were granted leave to intervene as parties: the Industrial Customers of Northwest Utilities (ICNU); Northwest Natural Gas Company, dba NW Natural; Noble Americas Energy Solutions LLC; Fred Meyer Stores and Quality Food Centers, Divisions of Kroger Co.; PacifiCorp, dba Pacific Power; the City of Portland, and the NW Energy Coalition. The Citizens' Utility Board of Oregon (CUB) intervened as a matter of right under ORS 774.180.

On the evening of May 29, 2014, we held a public comment hearing at Jefferson High School in Portland. Numerous members of the public and representatives from a variety of customer and community groups commented on the proposed increase in PGE' s rates. In addition, the Commission received public comments via e-mail, U.S. Mail, and telephone.

The parties conducted discovery, filed several rounds of testimony, and engaged in settlement discussions in both dockets. All issues were all ultimately resolved by the parties through the execution of three separate partial stipulations filed on July 17, September 2, and September 25, 2014, respectively. Each stipulation was supported by joint testimony or brief. No party opposes any of the stipulations. The stipulations are attached to this order as Appendices A-C.

III. DISCUSSION

The parties were able to settle all issues in the proceeding. We outline the nature of each partial stipulation, summarize each initially disputed issue that was the subject of the negotiated settlement in that stipulation, and provide our decision.

A. First Partial Stipulation

The first partial stipulation addresses most of the issues relating to PGE's general revenue requirement. Those issues are as follows.

1. Issues S-0 & S-3: Rate of Return, Capital Structure, Cost of Debt, and Interest Synchronization

In its initial filing, PGE requested a 10 percent return on equity[4], a slightly reduced cost of long-term debt at 5.557 percent, and maintaining the existing 50/50 debt/equity ratio, although it expected the level of regulated equity to exceed 50 percent.[5]

In the first partial stipulation, the parties settled issues related to capital structure and cost of debt, but not rate of return. The stipulating parties agree to a cost of long term debt of 5.443 percent and a capital structure of 50 percent equity and 50 percent long-term debt

[3] *See* Order No. 14-055.
[4] PGE/1200, Zepp/2.
[5] PGE/1100, Hagar-Valach-Greene/20, 22.

for the test year 2015. PGE also agrees to flow through to customers the benefit of lower interest rates resulting from the company's decision to issue shorter duration bonds in 2015 than the assumed ten-year term, with adjustments to interest costs based on the average daily spread of the month of June 2014.[6] The stipulating parties also agree that interest on debt will be included in the revenue requirement consistent with the updated adjustments to interest costs in the event PGE opts to change issued bonds duration during 2015 (Issue S-3, Interest Synchronization).[7]

Commission Resolution. We adopt the first partial stipulation settling the capital structure and cost of debt issues. Based on the evidence presented, we find the parties' joint proposal for cost of long-term debt of 5.443 percent and means for accurately capturing the cost of long-term debt as within the range of reasonableness for a company in PGE's circumstances. We also adopt the parties' proposal with respect to PGE's capital structure.

2. *Additional Issues Affecting the Revenue Requirement*

The first partial stipulation addressed the following additional issues, increasing other revenues and reducing expenses as described below.

a. *Issue S-1 Uncollectables*

PGE originally projected 0.50 percent in uncollectables. Under the stipulation, the parties agree on a 0.47 percent rate for the 2015 test year.[8]

b. *Issue S-4 Other Revenue*

PGE's 2015 forecasted other revenue was $23.5 million.[9] Commission Staff proposed adjustments based on historical actuals. After reviewing the forecasted amounts, the parties agreed that other revenue will be increased by $1.310 million as a reasonable outcome for settlement purposes.[10]

c. *Issue S-5 Advertising*

PGE's 2015 test year advertising expenses were forecasted at $2.382 million. The stipulation proposes to decrease these expenses by $0.052 million, subject to a further adjustment to equal 0.125 percent of the final revenue requirement in this rate case, including the docket UE 286 NVPC revenue requirement.[11]

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[6] First Partial Stipulation at 2.
[7] *Id.*
[8] Stipulating Parties/100, Gardner-Higgins-Jenks-Macfarlane/3.
[9] PGE/300, Tooman-Macfarlane/10.
[10] Stipulating Parties/100 at 5.
[11] First Partial Stipulation at 3.

d. Issue S-6 Customer Assistance

In its initial filing, PGE forecasted $14.158 million in customer assistance expenses. The stipulating parties agree to an adjustment based on escalating 2013 actuals for settlement purposes, and reduced these expenses by $0.277 million.[12]

e. Issue S-8 Sponsorships

In its initial filing, PGE forecasted $0.120 million in sponsorship expenses. In the stipulation, PGE agrees to remove these all these expenses, reducing test year expenses by a like amount.[13]

f. Issue S-9 Memberships

PGE's forecasted membership expenses were $3.6 million.[14] Under the stipulation, these expenses will be reduced by $0.103 million.[15]

g. Issue S-10 Energy Imbalance Market (EIM) Expenses

PGE initially proposed to capitalize the $1.5 million EIM expenses and amortize the amount over five years.[16] For settlement purposes, the parties agree that expenses related to the EIM will be reduced by $0.3 million, and the rate base will also be reduced by $1.5 million. When the costs for EIM are more clearly defined, PGE will file a request for an accounting order seeking to capitalize any incremental associated expenses.[17]

h. Issue S-14.2 Various Administrative and General (A&G) Expenses

Under the terms of the stipulated settlement, expenses included in FERC accounts 902, 903, 905, 921, 923, 924, 926, 928, and 935 for 2015 will be reduced by a total of $0.255 million.[18]

i. Issue S-15 Fee-free Bankcard Program

In the previous rate proceeding, we approved PGE's plan to launch a fee-free bankcard payment program by July 1, 2014, and to report to the Commission and the stipulating parties regarding take rates, relative use of debit and credit cards, and customer characteristics, no later than November 1 of this year. We allowed $0.5 million to be included in the 2014 test year for this purpose.[19]

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[12] Stipulating Parties/100 at 5.
[13] *Id.*
[14] PGE/700, Lobdell-Henderson-Tooman/31.
[15] First Partial Stipulation at 3.
[16] PGE/800, Quennoz-Weitzel/26-27.
[17] First Partial Stipulation at 4.
[18] *Id.*
[19] *See* Order No. 13-459 at 6 (Docket No. UE 262) (Dec 9, 2013).

In its initial filing, PGE indicated that it was on track to launch the program on schedule and eliminate transaction fees for credit or debit card payments. The rate case filing proposed to include $1.8 million for program costs.[20] Under the terms of the stipulation, the parties agree to reduce the expense to $1.5 million, delay the program launch four months, from July 1, 2014 to November 1, 2014, and have PGE defer the ratable share of included 2014 expenses, $0.5 million, and refund that amount to customers during 2015. PGE will provide the Commission with the customer utilization report no later than March 1, 2015. They also agree that, during 2015, the program would be limited to residential customers. The net effect is a $0.734 million reduction in Operation and Maintenance (O&M) expense.[21]

j. *<u>Issue S-18 Software Amortization</u>*

PGE's initial filing sought recovery of costs related to three software projects that were expected to be placed in service in May 2015. Those projects are Maximo Wave 2, Geographic Information System (GIS), and Outage Management System (OMS).

In discovery, PGE indicated that the Maximo Wave 2 plant would be placed in service by the end of 2014. Therefore, for settlement purposes, the parties agree to reduce PGE's test year expense by $0.928 million to remove amortization costs associated with the GIS and OMS systems, and to allow additional amortization of Maximo Wave 2. In addition, PGE's plant-in-service rate base will be increased by $28.912 million to account for the Maximo Wave 2 2014 project closing.[22]

k. *<u>Issue S-19 Property Tax</u>*

The stipulating parties agree that no adjustment should be made to PGE's filed property tax expense. In addition the parties agree to update property taxes consistent with any rate base change adopted by the Commission utilizing the appropriate tax rate.[23]

l. *<u>Issue S-22 Working Cash</u>*

Staff proposed to remove Materials and Supply (M&S) inventory from the rate base on concerns that PGE had double-counted M&S in the company's working cash. PGE maintains that accounting for M&S in both rate base and working cash was appropriate because it results in a decrease to the working cash factor.

The stipulating parties agree to a working cash factor of 3.70 percent and that an independent third party would be hired to perform a lead/lag study to evaluate whether there are any double counting issues. If the evaluation finds that the 2015 rate base should have been reduced relative to the amounts otherwise included in the 2015 revenue

[20] PGE/1000, Stathis-Dillin/13.
[21] Stipulating Parties/100 at 6; First Partial Stipulation at 4.
[22] *Id.* at 5, 7.
[23] *Id.*

requirement, the net effect will be subject to a deferral and refund as a reasonable outcome for settlement purposes.[24]

m. *Issue S-23 Confederated Tribes of Warm Springs Agreement*

PGE seeks recovery of costs associated with a power purchase contract between PGE and the Warm Springs Power and Water Enterprises (Warm Springs).[25] PGE and Warm Springs co-own the Pelton and Round Butte generation facilities, with PGE acting as the operator.[26] Warm Springs also owns an adjacent re-regulation generation facility from which it sells the entire output to PGE.[27] The stipulating parties agree that PGE's decision to enter into the purchased power agreement with Warm Springs is prudent.[28]

Commission Resolution. We have examined the record on each of the revenue requirement issues set forth above and adopt the parties' proposed resolutions. We find them to be sufficiently supported by the testimony and will contribute to the provision of reliable service at just and reasonable rates.

B. Second Partial Stipulation

The second partial stipulation addresses rate of return, increasing other revenues, reducing expenses, and prescribing study methodologies. It also resolves rate spread, rate design, and load forecasting issues as described below.

1. Issue S-0: Rate of Return

As noted above, in its initial filing, PGE requested 10 percent return on equity.[29] Under the terms of the second partial stipulation, PGE's authorized return on equity in this case will be 9.68 percent. The settlement figure is an estimate taken between the highest estimates in Staff's and ICNU's ranges, but lower than the company's estimate.[30]

Commission Resolution. We find the settlement figure to be a reasonable and supportable compromise. We therefore adopt the parties' second partial stipulation settling the rate of return issue.

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[24] *Id.* at 4-5.
[25] PGE/1500, Pope-Tooman/14-17.
[26] *Id.* at14.
[27] A re-regulation dam is generally located downstream of a hydro-electric facility to help control the flow of water downstream. Water can be stored behind the dam and released to mirror natural stream flows. A re-regulation facility can be used to generate electricity.
[28] Stipulating Parties/100 at 7.
[29] PGE/1200, Zepp/2.
[30] Stipulating Parties/200, Gardner-Higgins-Jenks-Macfarlane-Mullins/5.

2. *Other Revenue Requirement Issues*

The second partial stipulation addresses miscellaneous revenue requirement issues as described below.

a. *Issue S-2 Customer Accounts*

The stipulating parties agree that no adjustment to PGE's filed customer account expense should be made in this case.

b. *Issues S-7 Postage and S-14.1 Directors and Officers Insurance*

Although the parties could not reach an agreement on a specific reduction for each account, they note that the overall reduction adjustment of $0.900 million is based on postage increases closer to the rate of inflation and a sharing of "excess layers" of directors' and officers' insurance.[31]

c. *Issues S-11 and S-13 Compensation and Medical Benefits*

PGE's original filing sought an additional 11 full-time employees largely due to the work related to PW 2 and Tucannon. PGE also forecasted a 3.91 percent increase in overall wages and salaries, but made adjustments to account for vacancies and unfilled positions.[32]

The stipulating parties agree to a reduction to PGE's test year expense of $6.417 million and rate base of $2.583 million. In arriving at these figures, reductions are attributed to wages and salaries, the number of full-time equivalent employees, incentives, overtime, payroll taxes, and medical benefits. The parties did not agree on the specific makeup of the various components of the reductions, but it was agreed that they represent a balanced result for settlement purposes.[33]

d. *Issue S-12 Pension Costs*

In its initial filing, PGE requested recovery of 2015 pension expense and a return on the average 2015 prepaid pension asset, net of deferred taxes, through its inclusion in the rate base. The stipulating parties agree for settlement purposes to remove the prepaid pension asset and reduce the rate base by $45.5 million.[34]

e. *Issue S-17 Port Westward 2 and Tucannon River Wind Farm*

PGE seeks recovery of an additional $51.4 million in operating costs and return on investment for PW2 and an additional $46.7 million in operating costs and return on

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[31] *Id.*
[32] PGE/600, Barnett-Jaramillo/7-9, 10-24.
[33] Stipulating Parties/200 at 7.
[34] *Id.* at 5.

investment for Tucannon.[35] The plants are expected to be placed in service before March 31, 2015.

The stipulating parties agree that PGE's decisions to construct PW2 and Tucannon were prudent and that the Commission should approve the tariff riders requested by PGE.[36] For purposes of calculating the revenue requirement in this docket, the parties agree PGE should use a gross plant amount of $323.227 million for PW2 and $524.617 million for Tucannon. If the actual capital cost for each plant is lower than the stated amount, in 2016 PGE will refund the 2015 revenue requirement difference resulting from the lower capital costs, with interest, at its overall authorized cost of capital. If costs exceed the agreed amounts, the prudence of the incremental investments may be examined in the company's next general rate case.

PGE will file an attestation by an officer when each of the plants is placed in service and, if PW2 or Tucannon is not completed and in service by March 31, 2015, the conditions for review of the costs of the non-completed plant proposed by Staff in its Exhibit 902 will apply.[37]

f. *Issue S-24 Power Resources Cooperative (PRC)*

A dispute arose how PGE should credit customers with the proceeds from a transaction with Power Resources Cooperative (PRC). PRC owned a ten percent share of Boardman. Because PGE plans to close Boardman in 2020, PGE recently acquired PRC's share of the plant, and assumed PRC's obligations under a power purchase agreement (PPA) with a third party.

The transaction produced benefits to customers in two ways. First, due to an operating risk payment made by PRC, the acquisition produced proceeds of approximately $3.6 million. Second, the settlement of the third-party PPA produced proceeds of approximately $2.2 million.

PGE originally proposed to flow these credits to customers over a period extending from 2015 through 2020. ICNU proposed PGE provide all the credit 2015. In the stipulation, the parties agree that PGE will provide the credits to customers in 2015 and 2016, through Schedule 105.

[35] PGE/300, Tooman-Macfarlane/29-32.

[36] In its initial testimony in Docket No. UE 286, ICNU contended that, following the construction of PW2, PGE's Beaver Point-to-Point transmission contract with the Bonneville Power Administration was no longer necessary and therefore the full amount of the contract was not used and useful to deliver power from the Beaver generating station to load. The stipulating parties agreed to reduce PGE's NVPC by $2.5 million in docket UE 286 to resolve the issue. *See* Docket No. UE 286, Stipulating Parties/200, Crider-Higgins-Jenks-Mullins-Niman/3.

[37] Stipulating Parties/200 at 8.

g. Issue S-25, I-8 Environmental Remediation

PGE included a contingent liability of approximately $3.1 million in the test period to cover environmental remediation costs at the Downtown Reach area of the Willamette River. PGE sought to have the costs reclassified as a regulatory asset to be amortized over 20 years. If the proposed accounting treatment were approved, test year environmental costs would decrease by approximately $2.9 million.[38] ICNU sought to have the entire liability excluded from rates as not being known or measureable.[39]

Under the proposed stipulation, PGE's test year expense would be reduced by $1.55 million for the Downtown Reach area, due to PGE's revised estimate that half of the forecasted $3.1 million of expenses will be spent in 2015. PGE also agree to withdraw its request of an accounting order relating to environmental remediation of the Downtown Reach area and Portland Harbor generally.[40]

h. Production Tax Credits

In its opening testimony, ICNU recommended that PGE remove production tax credit carry-forwards from rate base to the extent that they could have been used in the test year based on PGE's normalized taxes.[41] In the stipulation, the parties agree to reduce PGE's revenue requirement by one million dollars to resolve this issue.[42]

i. Issue I-9 PGE's Renewable Portfolio Standard (RPS) Carve-Out Proposal

PGE currently recovers the variable power costs and benefits associated with resources used to comply with Oregon's renewable portfolio standard (RPS) through its annual power cost update and power cost adjustment mechanism (PCAM). It also recovers the variable tax benefits associated with production tax credits from RPS resources in base rates. However, as a result of deadbands, sharing bands and earnings tests included in its PCAM calculation, PGE claims that it is not recovering all of its costs associated with RPS resources in rates. PGE proposed to create a new automatic adjustment clause that would allow it to true-up variances associated with renewable resources. PGE refers to this proposal as a "carve out" because it would allegedly remove the variable RPS costs from the company's PCAM.[43]

As part of the second partial stipulation, PGE agrees to withdraw its RPS carve-out proposal from the case.[44]

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[38] PGE/700, Lobdell-Henderson-Tooman/15.
[39] ICNU/100, Mullins/23.
[40] Stipulating Parties/200, Gardner-Higgins-Jenks-Macfarlane-Mullins/6.
[41] ICNU/100, Mullins/14-17.
[42] Stipulating Parties/200 at 8.
[43] ICNU/100, Mullins/5, *citing* PGE/500, Niman-Peshka-Hager/44.
[44] Stipulating Parties/200 at 9.

Commission Resolution. We have examined the record on each of the revenue requirement issues set forth above and adopt the parties' proposed resolutions. We find them to be sufficiently supported by the testimony and will contribute to the provision of reliable service at just and reasonable rates.

3. Rate Spread, Rate Design, and Load Forecasting Issues

The parties agreed that, except with respect to the issues discussed below, it is appropriate to spread costs among the individual rate schedules using PGE's filed marginal cost study and the rate design principles contained in PGE's initial filing.[45] Contested portions of PGE's rate filing were modified by the stipulation and resolved as follows.

a. Issue I-2 Customer Service Marginal Cost Study

This issue relates to how marginal costs are calculated. PGE averages the marginal costs of Schedule 89—Customers larger than 4000kW, and Schedule 90—Customers larger than 100MWa. In contrast, Staff calculates the marginal costs of the two schedules separately because it contends that the customers place a significantly different type of cost burden on PGE and Staff believes its proposal is a more equitable calculation. Staff also identified an input error in the billing costs of the lighting schedule while reviewing the PGE study.[46]

The stipulating parties agree to incorporate Staff proposals related to three identified customer marginal costs items, correct a minor error in the billing calculations for outdoor lighting, and to separately identify the customer marginal costs for Schedules 89 and 90. However, in the interest of settlement, the parties agree that Schedules 89 and 90 customers' marginal costs will continue to be averaged as PGE initially proposed.[47]

b. Issue I-3 Line Extension Refunds

Under its current line extension policy, PGE bills customers for quoted costs rather than actual costs. In nearly every work order that our Staff reviewed, the quote was higher than the actual cost, with many work orders having an actual cost less than half the amount of the job quote. As a result, Staff believes that PGE may be over-collecting costs.[48] Staff identifies three issues: identifying customers eligible for refunds, accounting for refunds, and informing customers of the maximum potential refund they may be able to receive at a future date.

To resolve these issues, the stipulating parties agree that PGE will: (1) create an electronic database of potential customers eligible for line extension refunds; (2) continue to account for refunds in the manner outlined by Staff; and (3) make adjustments to the

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[45] *Id.* at 3-4.
[46] Staff/300, Kaufman/40-41.
[47] Stipulating Parties/200 at11.
[48] Staff/300, Kaufman/45.

current line extension agreement that will make the notification about the potential for a refund more prominent.[49]

c. *Issue I-4 Generation Marginal Cost Study*

Consistent with the partial stipulation, in the company's previous general rate case, docket UE 262, PGE excluded wind resources in its generation marginal cost studies in this docket.[50] Staff proposed to include wind energy in the generation marginal cost study, but the parties could not agree on an appropriate methodology. However, because the difference in the marginal energy cost values as calculated by PGE and Staff were relatively small,[51] the stipulating parties agree that Staff's calculated marginal cost would be used, subject to the outcome of negotiations on CUB's proposal to include energy efficiency in the marginal cost of service study.[52]

d. *Issue I-1 Rate Design Schedule 7 Basic Charge*

PGE proposed to increase the residential service Schedule 7 monthly base rate from $10 to $11. Staff opposed this proposed 10 percent increase as being well above the summed marginal cost of universally accepted customer-cost/basic-charge components.[53] The stipulating parties agree to maintain the current $10/month Schedule 7 basic charge.[54]

e. *Issue I-1 Rate Design Schedules 83, 85, 89, and 90 On/Off Peak Pricing Differential*

Staff proposed modifications to PGE's rate design to more closely align peak demand costs with scheduled rates.[55] The stipulating parties agree for the purposes of settlement to maintain the current pricing structure but to increase the differential between on- and off-peak prices from 1.0 cents/kWh to 1.5 cents/kWh for Schedules 83, 85, 89, and 90, which better reflected costs. The secondary/primary demand and facility charge price differential for Schedule 85 and its direct access equivalents would be maintained at their current levels.[56] They also agree to participate in a pricing workshop in 2015 to discuss Staff's and others' pricing proposals.[57]

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[49] Stipulating Parties/200 at 10-11.

[50] *See In the Matter of Portland General Electric Company Request for General Rate Revision,* Order No. 13-459, Appendix A at 6. (Dec 9, 2013). Note: Stipulating Parties/200, Gardner-Higgins-Jenks-Macfarlane-Mullins/12, line 1, erroneously attributes the wind resource exclusion to the second partial stipulation in that docket.

[51] PGE found a value of $49.88/MWh; Staff's calculated value was $51.26/MWh. (Stipulating Parties/200, at 12.)

[52] *Id.* The CUB proposal is addressed later in this order in our discussion of the third partial stipulation.

[53] Staff/700, Compton/11.

[54] Stipulating Parties/200 at 13.

[55] Staff/700, Compton/6-11.

[56] Second Partial Stipulation at 5-6.

[57] Stipulating Parties/200 at13.

f. Customer Impact Offset (CIO)

The CIO is a mechanism that represents departures from strict cost-of-service allocations; it is designed to achieve greater rates simplicity, comprehension, and acceptability and to mitigate the effects of cost-justified increases that greatly exceed the system overall average increase. Staff proposed adjustments through the CIO mechanism that in some cases would partly offset increases caused by integrating wind in the marginal costs analysis.[58]

To implement these adjustments, the stipulating parties agree that it is appropriate to cap the base rate change for irrigation schedules at the greater of 12 percent or three times the overall base rate change, and that no rate schedule would contribute to the CIO mitigation if their base rate change exceeds the average base rate change by more than 1.5 percent.[59]

g. Issue S-16 Load Forecasting

The stipulation we adopted in docket UE 228 specified that, in annual update tariff (AUT) dockets where the overall projected impact of the Schedule 125 change is less than three percent, a price elasticity adjustment would not be included in the load forecast.[60] In this docket, Staff proposed and the stipulating parties agree that, in years when PGE has a general rate case, the price elasticity adjustment should be included in the load forecast regardless of the size of the requested price change. Moreover, the parties agree that the same load forecast would be used for both the general rate case and the AUT docket, if separate. The parties also ask that, by accepting this change, the Commission should signify that it has modified the agreement submitted and adopted in docket UE 228.[61]

h. Issue I-6 Reactive Demand Charge

Staff recommended that PGE prepare a study on the costs related to reactive power[62] in order to update the reactive demand charge. PGE's filed marginal cost study did not account for reactive power. Staff stated that, if there appears to be a significant cost shifting due to reactive power, PGE should incorporate those costs into the marginal cost study.[63]

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[58] Staff/700, Compton/3 at fn 1.
[59] Stipulating Parties/200 at 13.
[60] *In the Matter of Portland General Electric Company2012 Annual Power Cost Update Tariff (Schedule 125).* Order No. 11-432, Appendix A at 2 (Nov 2, 2011).
[61] Stipulating Parties/200 at 13-14.
[62] "Reactive power" is non-working power that results from the misalignment of the current and voltage wave patterns of alternating current. If the waves do not match, some of the power being generated is not performing real work and causes the apparent power to drop. (Staff/300, Kaufman/46-47).
[63] *Id.*

The stipulating parties agree that PGE would perform a kVar cost study and present the results in an appropriate pricing workshop prior to the filing of its next general rate case.[64]

Commission Resolution. We have examined the record on each of the rate spread, rate design, and load forecasting issues set forth above and adopt the parties' proposed resolutions. We find them to be sufficiently supported by the testimony and will contribute to the provision of reliable service at just and reasonable rates. We also grant the parties' request to modify the stipulation adopted in our Order No. 11-432 in docket UE 228.

C. Third Partial Stipulation

The third partial stipulation addresses CUB's proposal that energy efficiency, as a marginal resource, should be included in the marginal cost-of-service study. The stipulating parties request we open an investigation to consider whether customers with loads greater than 1 aMW are receiving a direct benefit from conservation measures funded by amounts collected under Senate Bill 838 and whether changes to marginal cost study methodologies are in order.

Commission Resolution. We grant the parties' request to open an investigation to address the question of energy efficiency's inclusion as an energy resource in future marginal cost-of-service studies made in conjunction with general rate cases.

IV. CONCLUSION

We have reviewed the testimony presented by the parties and the comments filed with the Commission by numerous customers and others with an interest in this proceeding, and conclude that our decisions in this docket will result in rates that are fair, just and reasonable.

V. ORDER

IT IS ORDERED that:

1. The first, second, and third partial stipulations between the Staff of the Public Utility Commission of Oregon; Portland General Electric Company; the Citizens' Utility Board of Oregon; Fred Meyer Stores and Quality Food Centers, Divisions of Kroger Co.; and the Industrial Customers of Northwest Utilities, attached to this order as Appendices A-C, respectively, are adopted.

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[64] Second Partial Stipulation at 3.

2. Portland General Electric Company's Final Revenue Requirement and Pricing Update attached to this order as Appendix D is adopted.

3. Paragraph number 4 of the stipulation adopted in Order No. 11-432 is modified to the extent indicated above.

4. Advice No. 14-03 is permanently suspended.

5. Portland General Electric Company must file new tariffs consistent with this order and Order Nos. 14-316 and 14-355 entered in Docket No. UE 286, by December 16, 2014, to be effective January 1, 2015.

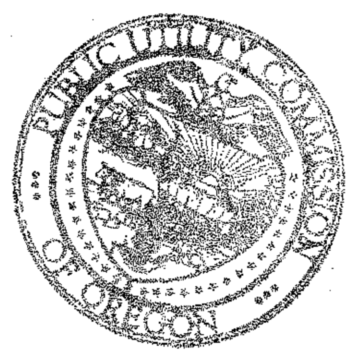
6. The Commission will open an investigation to address the issues as set forth in the third partial stipulation.

Made, entered and effective DEC 04 2014.

Susan K. Ackerman
Chair

John Savage
Commissioner

Stephen M. Bloom
Commissioner



A party may request rehearing or reconsideration of this order under ORS 756.561. A request for rehearing or reconsideration must be filed with the Commission within 60 days of the date of service of this order. The request must comply with the requirements in OAR 860-001-0720. A copy of the request must also be served on each party to the proceedings as provided in OAR 860-001-0180(2). A party may appeal this order by filing a petition for review with the Court of Appeals in compliance with ORS 183.480 through 183.484.

BEFORE THE PUBLIC UTILITY COMMISSION OF OREGON

UE 283

In the Matter of PORTLAND GENERAL ELECTRIC COMPANY Request for a General Rate Revision.	))))))	**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"), Fred Meyer Stores and Quality Food Centers, Division of Kroger Co. ("Kroger"), and the Industrial Customers of Northwest Utilities ("ICNU") (collectively, the "Stipulating Parties").

On February 13, 2014, PGE filed this general rate case. On March 7, 2014, a prehearing conference was held. A procedural schedule was established to resolve issues relating to the general rate revision. A separate docket was established, Docket No. UE 286, for consideration of issues related to PGE's Net Variable Power Costs and Annual Power Cost Update. PGE has requested that the revised rates pursuant to this general rate case become effective January 1, 2015. PGE has responded to over 800 data requests in this docket from Staff and other parties.

Prior to the Settlement Conference scheduled for May 20, 2014, Staff provided to the other parties in this docket its settlement proposal that included numerous proposed adjustments to PGE's filed case. On May 20, 2014, the Stipulating Parties participated in a Settlement Conference regarding this docket. All parties were invited to participate. A subsequent settlement conference was held on May 27, 2014. Parties also discussed the cost of long-term debt at a settlement teleconference on June 12, 2014. As a result of those discussions the Stipulating Parties have reached a compromise settlement of a number of issues in this docket, as described in detail below.

TERMS OF PARTIAL STIPULATION

1. This Partial Stipulation resolves the issues identified below.

   a. S-0 Capital Structure and Cost of Debt. For ratemaking purposes, the Stipulating Parties agree to a capital structure of 50% equity and 50% long-term debt for test year 2015. The Stipulating Parties also agree to PGE's cost of long-term debt equal to 5.443 percent. This cost of debt is comprised, for 2014 and 2015, of the following issuances, amounts and costs:

Issuances		Maturity	All-In
Year	$M	in Years	Cost
2014	100	31	4.432%
2014	100	32	4.481%
2014	80	10	3.594%
2015	125	10	3.702%

   Should PGE opt to issue shorter duration bonds in 2015 than the assumed ten-year term, the benefit of the lower interest rate, will be deferred for refund to customers, with the adjustment to interest costs based on the average daily spreads of the month of June 2014.

   b. S-1 Uncollectibles. An uncollectible rate of 0.47% will be used in this case.

   c. S-3 Interest Synchronization. Interest on debt will be included in the revenue requirement consistent with the update agreed to in S-0.

d. S-22 Working Cash. A working cash factor of 3.70% will be used in deriving revenue requirement. The Stipulating Parties further agree that an independent third party will be hired to perform an adequately funded lead/lag study and to thoroughly evaluate the existence and amount, if any, of any double counting between working capital and inclusion of materials and supplies in rate base. To the extent such evaluation reveals that PGE's rate base for 2015 should have been reduced relative to the amounts otherwise included in the 2015 revenue requirement, the revenue requirement effect will be subject to deferral and refund to customers. This deferral will apply to a one-year period only – calendar year 2015.

e. S-4 Other Revenue. PGE's proposed 2015 Other Revenues will be increased by $1.310 million.

f. S-5 Advertising. PGE's test year advertising expenses will be decreased by $0.052 million from the amount in PGE's initial filing. Advertising expenses will be further adjusted to equal 0.125 percent of the final revenue requirement approved in this docket, including the power cost revenue requirement determined in Docket No. UE 286.

g. S-6 Customer Assistance. Test year customer assistance expenses will be reduced by $0.277 million.

h. S-8 Sponsorships. 2015 test year expenses for sponsorships will be decreased by $0.120 million.

i. S-9 Memberships. Membership expenses included in the test year will be decreased by $0.103 million.

j. S-14.2 Various A&G. Expenses included in FERC accounts 902, 903, 905, 921, 923, 924, 926, 928, 930, and 935 for 2015 will be reduced by a total of $0.255 million.

k. S-10. For settlement purposes, the Stipulating Parties agree that PGE's proposed 2015 expenses related to the Energy Imbalance Market will be reduced by $0.300 million, and rate base will also be reduced by $1.5 million. PGE will also, when its cost for EIM are more clearly defined, file a Request for an Accounting Order seeking to capitalize any incremental expenses associated with EIM. .

l. S-15 Fee-free Bankcard Program. In docket UE 262, PGE's 2014 test year rate case, it was agreed that PGE would implement a fee-free bankcard payment program for residential customers beginning July 1, 2014. $0.5 million was included in 2014 test year revenue requirement for this program. As explained in the supporting testimony, the Stipulating Parties agree that PGE should delay implementation of this program until November 1, 2014. PGE agrees to defer the ratable share of included 2014 expenses, 2/3 of $500,000, for refund to customers during 2015. In addition, the Stipulating Parties agree that the fee-free bankcard program will be limited to residential customers only during 2015. PGE will provide a report to the OPUC and Stipulating Parties on the adoption rate, relative use of debit cards to credit cards, and the characteristics of customers using this program. The PGE report will be circulated to the Stipulating Parties no later than March 1, 2015. Test year expenses for the bankcard program will be reduced by $0.734 million from PGE's initial filing.

m. S-18 Software Amortization. The Stipulating Parties agree that amortization expense associated with the Geographic Information System and Outage Management System will be removed from PGE's 2015 revenue requirement. PGE's proposed 2015 expenses for software amortization will be reduced by \$0.928 million. In addition, PGE's plant-in-service rate base will be increased by \$28.912 million to account for the Maximo Wave 2 project closing in 2014. PGE will provide an attestation by a corporate officer that the Maximo Wave 2 system has been closed to plant prior to the end of 2014.

n. S-19 Property Tax. There will be no adjustment to PGE's filed case except as consistent with any rate base change adopted by the Commission utilizing the appropriate property tax rate.

o. S-23 Confederated Tribes of Warm Springs agreement. The Stipulating Parties agree that PGE's decision to enter into the purchased power agreement with the Confederated Tribes of Warm Springs as outlined in PGE Exhibit 1500 is prudent.

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 Parties agree that this Stipulation is in the public interest, and will meet the standard in ORS 756.040.

5. The Parties agree that this Stipulation represents a compromise in the positions of the parties. Without the written consent of all 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 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 order. Nothing in this paragraph provides any Party the right to withdraw from this Stipulation as a result of the Commission's resolution of issues that this Stipulation does not resolve.

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 except for ICNU, 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 Party shall be deemed to have approved, admitted or consented to the facts, principles, methods or theories employed by any other Party in arriving at the terms of this Stipulation. Except as provided in this Stipulation, no 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 17th day of July, 2014.

ORDER NO. 14 422

PORTLAND GENERAL ELECTRIC COMPANY

STAFF OF THE PUBLIC UTILITY

COMMISSION OF OREGON

CITIZENS' UTILITY BOARD OF OREGON

INDUSTRIAL CUSTOMERS OF NORTHWEST UTILITIES

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THE KROGER CO.

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

UE 283

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

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"), Fred Meyer Stores and Quality Food Centers, Division of Kroger Co. ("Kroger"), and the Industrial Customers of Northwest Utilities ("ICNU") (collectively, the "Stipulating Parties").

The Stipulating Parties previously submitted a Partial Stipulation resolving a number of issues in this docket. Subsequent to the time the agreements contained in that Partial Stipulation were reached, the Stipulating Parties continued settlement discussions. Settlement Conferences were held on July 7, 8, 11, and 28, and August 19, 2014. As a result of those discussions, the Stipulating Parties have reached a compromise settlement of a number of issues in this docket, as described in detail below. With this Stipulation, the Stipulating Parties have resolved all issues in this docket except for CUB's proposal to include energy efficiency in the marginal cost of service study.

TERMS OF SECOND PARTIAL STIPULATION

1. This Partial Stipulation resolves the issues identified below.

   a. S-2 Customer Accounts. There will be no adjustment for this issue.

   b. S-7 Postage and S-14.1 D&O Insurance. Test-year expense will be reduced by a total of $0.9 million for these two issues.

   c. S-12 Pension. Rate base in this docket will be reduced by $45.5 million.

   d. S-17 Rate Base. Test-year rate base will be reduced by a total of $80 million. Of this amount, $32.7 million relates to a correction of deferred taxes included in rate base and $10 million is in recognition of past capitalized financial performance based incentives. For regulatory purposes, this $10 million rate base adjustment will be amortized over 20 years. This resolves all issues regarding past capitalization of incentives. Beginning in 2015, PGE will not capitalize financial performance based incentives. The $80 million reduction does not include, but is cumulative to, rate base reductions agreed to in the Partial Stipulation filed with the Commission on July 17, 2014.

   e. S-25 Environmental Remediation. Test-year expense will be reduced to $1.55 million. PGE's request for an accounting order is withdrawn.

   f. S-11 and S-13 Compensation and Medical Benefits. To resolve all issues regarding compensation, benefit costs, employee numbers (FTEs) and all other compensation-related issues, test year expenses will be reduced by $9.0 million divided between O&M and capital resulting in a $6.417 million reduction to O&M expense and a $2.583 million reduction to rate base.

g. Power Resources Cooperative (PRC). To resolve ICNU's issues regarding PGE's acquisition of PRC's 10% ownership share of the Boardman plant, PGE agrees to an earlier payment to customers for: 1) the net economic value of the transaction, totaling approximately $3.6 million; and 2) the power purchase agreement bookout, totaling approximately $2.2 million. These payments will be refunded through Schedule 105 over the calendar years 2015 and 2016.

h. Load Forecast Price Elasticity. In docket UE 228, the Commission approved a stipulation between PGE, Staff, and CUB, which provided that in AUT dockets where the overall projected impact of the Schedule 125 change is less than 3%, a price elasticity adjustment would not be included in the load forecast. In this docket Staff proposed, and the other Stipulating Parties agree, that in years when PGE has a general rate case, a price elasticity adjustment should be included in the load forecast used for the rate case and the AUT docket if separate, regardless of the size of the requested price change. The Stipulating Parties request that the Commission, through approval of this Stipulation, modify the agreement submitted in docket UE 228. The Stipulating Parties that are also taking an active role in PGE's current AUT proceeding, Docket UE 286, will submit a stipulation in that docket consistent with this paragraph.

i. Reactive Power. At the request of Staff, PGE will perform a KVAR cost study prior to its next general rate case. PGE will present the results of the study at an appropriate pricing workshop prior to its next general rate case.

j. Port Westward 2 and Tucannon River Wind Farm. The Stipulating Parties agree that PGE's decisions to construct Port Westward 2 ("PW2") and Tucannon River

Wind Farm ("Tucannon") were prudent and that the Commission should approve the PW2 and Tucannon tariff riders requested by PGE to reflect the prudently incurred costs and benefits of those plants in rates when they begin providing service to customers with the following changes and additions:

i. For determining rates in this docket only, the gross plant for PW2 will be \$323,227,000 and the gross plant for Tucannon will be \$524,617,000. If actual capital costs for PW2 or Tucannon are lower than the stated amounts, PGE will refund the 2015 revenue requirement difference resulting from the lower capital costs, with interest at its overall authorized cost of capital, beginning January 1, 2016. If PW2 or Tucannon capital costs are higher than the designated amount, parties may examine the prudence of such additional costs in PGE's next general rate case.

ii. PGE will file attestation by an officer when each of the two plants is placed in service.

iii. If PW2 or Tucannon is not completed and in service by March 31, 2015, the conditions for review of the costs of the non-completed plant or plants proposed by Staff in its Exhibit 902 will apply.

iv. Power Cost Adjustment. As part of the settlement of matters in this docket, including issues regarding the prudence of PW2 and Tucannon, and PGE's election of Bonneville Power Administration's Variable Energy Resource Balancing Service 30/60 committed scheduling for integration of Biglow and Tucannon, the Stipulating Parties have agreed to, and will stipulate to, a $2.5 million reduction of PGE's net variable power cost in the related power cost docket, UE 286.

k. Customer Marginal Cost. Staff's proposals regarding costs for printing and mailing, specialized billing, and electronic billing will be incorporated in the marginal cost study in this docket. The marginal costs for Schedules 89 and 90 will continue to be averaged as proposed in PGE's initial testimony.

l. Line Extensions. In the Line Extension Agreement signed by PGE and the customer, PGE will make more prominent the maximum refund a customer may be due when other customers connect to the line. After PGE has fully implemented the Maximo Wave 2 project and asset management system, anticipated to be in October 2014, PGE will electronically track potential line extension refunds.

m. Pricing. The Schedule 7 Basic Charge will remain $10.00 per month. The on/off peak energy price differential for Schedules 83, 85, 89, and 90 will increase to 1.5 cents per kWh. PGE will host a workshop with the Stipulating Parties in 2015 to discuss pricing issues, including the proposals Staff and other parties raised in this docket. Customer impact offset contributions will be limited so that tariff schedules do not contribute to the extent the schedule's increase is more than 1.5% more than the overall cost of service price increase. Increases for Schedules 47 and 49 will be limited to the greater of 12% or three times the overall cost of service price increase.

n. Generation Marginal Cost. For purposes of settlement, the results of Staff's proposed generation marginal cost methodology, adjusted to account for using

RECs to meet a portion of the RPS requirements, will be used in this docket with the caveat that CUB's proposal to include energy efficiency in the marginal cost of service study, if adopted, would modify the Staff marginal cost study. Other parties do not agree that the methodology would be appropriate for use in future dockets.

o. Kroger. Consistent with the recommendation of Kroger, the secondary/primary demand and facility charge price differential for Schedule 85 and its direct access equivalents will be maintained at their current levels.

p. RPS Carve-out. PGE withdraws its proposal to carve out from its power cost adjustment mechanism the costs associated with its resources used to meet Oregon's renewable portfolio standard.

q. Production Tax Credits. In consideration of ICNU's proposal to remove production tax credit carry-forwards from rate base, PGE agrees to reduce revenue requirement by $1 million.

r. Return on Equity. PGE's authorized return on equity in this case will be 9.68%.

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. Nothing in this paragraph provides any Stipulating Party the right to withdraw from this Stipulation as a result of the Commission's resolution of issues that this Stipulation does not resolve.

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 2nd day of September, 2014.

ORDER NO. 14 422

PORTLAND GENERAL ELECTRIC
COMPANY

STAFF OF THE PUBLIC UTILITY

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THE KROGER CO.

BEFORE THE PUBLIC UTILITY COMMISSION OF OREGON

UE 283

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

This Third Partial Stipulation ("Third Partial 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"), Fred Meyer Stores and Quality Food Centers, Division of Kroger Co. ("Kroger"), and the NW Energy Coalition ("NW Energy") (collectively, the "Stipulating Parties").

Some of the Stipulating Parties previously submitted two Partial Stipulations that between them resolved all contested issues in this docket with the exception of CUB's proposal to include energy efficiency in the marginal cost of service study. This Third Partial Stipulation resolves, for purposes of this docket only, that remaining issue.

TERMS OF THIRD PARTIAL STIPULATION

1. In consideration of the other Stipulating Parties' agreement to jointly request with CUB that an investigatory docket be opened to consider the question of whether customers with loads greater than 1 aMW are receiving a direct benefit from conservation measures funded by amounts collected pursuant to Senate Bill ("SB") 838, CUB has now agreed to resolve the outstanding marginal cost/rate spread issue in this UE 283 PGE General Rate

Case docket. CUB further agrees to the positing of several additional questions proposed by the other Stipulating Parties.

2. The Stipulating Parties request that the investigatory docket be opened to address the following questions:

   - Are customers with loads greater than 1 aMW receiving a direct benefit from conservation measures funded by amounts collected pursuant to SB838?
   - What is the meaning of "any direct benefit" as used in ORS 757.689(2)(b)?
   - Are there any barriers that prevent the ETO from obtaining all cost-effective energy efficiency?
   - If such barriers exist, what other options exist to gain all cost effective energy efficiency, including from customers with loads greater than 1 aMW?
   - Should the ETO approach to funding energy efficiency be flexible to take advantage of energy efficiency savings brought about by changes in technology and the economy?
   - Should there continue to be a cap of 18.4% on energy efficiency funding provided by the ETO to PGE customers with loads greater than 1 aMW, and if so, what criteria should be used to set such a cap?

3. As a part of this settlement, CUB no longer requests that the Commission implement its energy efficiency related marginal cost/rate spread proposal in this docket. The Second Partial Stipulation filed in this docket stated in paragraph 1(n):

   > For purposes of settlement, the results of Staff's proposed generation marginal cost methodology, adjusted to account for using RECs to meet a portion of the RPS requirements, will be used in this docket with the caveat that CUB' s proposal to include energy efficiency in the marginal cost of service study, if adopted, would modify the Staff marginal cost study.

All Stipulating Parties agree that as a result of the agreement in this Third Partial Stipulation, Staff's proposed generation marginal cost methodology, adjusted to account for using RECs to meet a portion of the RPS requirements, should be implemented in this docket.

4. The Stipulating Parties agree that testimony and data responses in this UE 283 docket that are relevant to the questions to be addressed in the requested investigatory docket, may be submitted into evidence in the investigatory docket.

5. The Stipulating Parties recommend and request that the Commission approve this Third Partial Stipulation, which together with the Partial Stipulation and Second Partial Stipulation previously filed in this docket, result in an appropriate and reasonable resolution of the identified issues in this docket. The Stipulating Parties agree that together, the Partial Stipulation, Second Partial Stipulation and Third Partial Stipulation resolve all contested issues in this docket.

6. The Stipulating Parties agree that this Third Partial 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.

7. The Stipulating Parties agree that this Third Partial 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.

8. The Stipulating Parties have negotiated this Third Partial Stipulation as an integrated document. The Stipulating Parties will request Commission approval of this Third Partial Stipulation. If the Commission rejects all or any material part of this Third Partial Stipulation, or adds any material condition to any final order that is not consistent with this Third Partial Stipulation, each Stipulating Party reserves its right: (i) to withdraw from the Third Partial 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 Third Partial 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 Third Partial 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. Nothing in this paragraph provides any Stipulating Party the right to withdraw from this Third Partial Stipulation as a result of the Commission's resolution of issues that this Third Partial Stipulation does not resolve.
9. This Third Partial 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 Third Partial Stipulation throughout this proceeding and in any appeal, and provide witnesses to support this Third Partial Stipulation (if specifically required by the Commission), and recommend that the Commission issue an order adopting the settlements contained herein. By entering into this Third Partial 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 Third Partial 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.

10. This Third Partial 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 24th day of September, 2014.

PORTLAND GENERAL ELECTRIC COMPANY

STAFF OF THE PUBLIC UTILITY

COMMISSION OF OREGON

CITIZENS' UTILITY BOARD OF OREGON

INDUSTRIAL CUSTOMERS OF NORTHWEST UTILITIES

THE KROGER COMPANY

NW ENERGY COALITION

DATED this 18th day of September, 2014.

PORTLAND GENERAL ELECTRIC COMPANY

STAFF OF THE PUBLIC UTILITY COMMISSION OF OREGON

CITIZENS' UTILITY BOARD OF OREGON

INDUSTRIAL CUSTOMERS OF NORTHWEST UTILITIES

THE KROGER COMPANY

NW ENERGY COALITION

ORDER NO. 14 422

DATED this 22nd day of September, 2014.

PORTLAND GENERAL ELECTRIC
COMPANY

STAFF OF THE PUBLIC UTILITY

COMMISSION OF OREGON

CITIZENS' UTILITY BOARD
OF OREGON

INDUSTRIAL CUSTOMERS OF
NORTHWEST UTILITIES

THE KROGER COMPANY

NW ENERGY COALITION

DATED this _______ day of September, 2014.

PORTLAND GENERAL ELECTRIC
COMPANY

STAFF OF THE PUBLIC UTILITY

COMMISSION OF OREGON

CITIZENS' UTILITY BOARD
OF OREGON

S. Bradley Van Cleve

INDUSTRIAL CUSTOMERS OF
NORTHWEST UTILITIES

THE KROGER COMPANY

NW ENERGY COALITION

DATED this _______ day of September, 2014.

PORTLAND GENERAL ELECTRIC COMPANY

STAFF OF THE PUBLIC UTILITY COMMISSION OF OREGON

CITIZENS' UTILITY BOARD OF OREGON

INDUSTRIAL CUSTOMERS OF NORTHWEST UTILITIES

K Bahm

THE KROGER COMPANY

NW ENERGY COALITION

DATED this 23rd day of September, 2014.

____
PORTLAND GENERAL ELECTRIC COMPANY

____
STAFF OF THE PUBLIC UTILITY COMMISSION OF OREGON

____
CITIZENS' UTILITY BOARD OF OREGON

____
INDUSTRIAL CUSTOMERS OF NORTHWEST UTILITIES

____
THE KROGER COMPANY

____
NW ENERGY COALITION

Portland General Electric Company
2015 Revenue Requirement Summary
Dollars in $000s

	Rev Req	Percent
Total Increase:	44,329	2.56%

	Base Business 2015 (1)	PW2 (2)	Tucannon (3)	Total Results (4)
1 Sales to Consumers	1,686,800	48,954	42,993	1,778,746
2 Sales for Resale	-	-	-	-
3 Other Revenues	25,798	-	-	25,798
4 Total Operating Revenues	1,712,597	48,954	42,993	1,804,544
5 Net Variable Power Costs	581,359	(510)	(18,541)	562,308
6 Production O&M (excludes Trojan)	141,125	1,479	7,470	150,074
7 Trojan O&M	68	-	-	68
8 Transmission O&M	15,028	-	-	15,028
9 Distribution O&M	94,623	-	-	94,623
10 Customer & MBC O&M	69,084	-	-	69,084
11 Uncollectibles Expense	7,928	230	202	8,360
12 OPUC Fees	5,271	153	134	5,559
13 A&G, Ins/Bene., & Gen. Plant	140,073	347	435	140,854
14 Total Operating & Maintenance	1,054,559	1,699	(10,300)	1,045,958
15 Depreciation	234,608	9,491	23,209	267,308
16 Amortization	32,872	-	-	32,872
17 Property Tax	51,016	1,663	6,943	59,623
18 Payroll Tax	14,033	30	7	14,070
19 Other Taxes	1,835	-	-	1,835
20 Franchise Fees	42,190	1,224	1,075	44,489
21 Utility Income Tax	57,642	10,708	(16,195)	52,155
22 Total Operating Expenses & Taxes	1,488,754	24,815	4,740	1,518,309
23 Utility Operating Income	223,843	24,139	38,253	286,235
24 Rate Base				
25 Avg. Gross Plant	7,276,617	323,227	524,617	8,124,460
26 Avg. Accum. Deprec. / Amort	(3,806,332)	(5,800)	(11,604)	(3,823,736)
27 Avg. Accum. Def Tax	(612,284)	890	(7,300)	(618,694)
28 Avg. Accum. Def ITC	-	-	-	-
29 Net Utility Plant	2,858,001	318,316	505,713	3,682,030
30 Misc. Deferred Debits	29,352	-	-	29,352
31 Operating Materials & Fuel	75,103	-	-	75,103
32 Misc. Deferred Credits	(57,240)	-	-	(57,240)
33 Working Cash	55,084	918	175	56,177
34 Rate Base	2,960,300	319,234	505,888	3,785,422
35 Rate of Return	7.562%			7.562%
36 Implied Return on Equity	9.680%			9.680%

ORDER NO.

	Base Business 2015	PW2	Tucannon	Total Results
	(1)	(2)	(3)	(4)
37 Effective Cost of Debt	5.443%	5.443%	5.443%	5.443%
38 Effective Cost of Preferred	0.000%	0.000%	0.000%	0.000%
39 Debt Share of Cap Structure	50.000%	50.000%	50.000%	50.000%
40 Preferred Share of Cap Structure	0.000%	0.000%	0.000%	0.000%
41 Weighted Cost of Debt	2.722%	2.722%	2.722%	2.722%
42 Weighted Cost of Preferred	0.000%	0.000%	0.000%	0.000%
43 Equity Share of Cap Structure	50.000%	50.000%	50.000%	50.000%
44 State Tax Rate	7.614%	7.614%	7.614%	7.614%
45 Federal Tax Rate	35.000%	35.000%	35.000%	35.000%
46 Composite Tax Rate	39.949%	39.949%	39.949%	39.949%
47 Bad Debt Rate	0.470%	0.470%	0.470%	0.470%
48 Franchise Fee Rate	2.501%	2.501%	2.501%	2.501%
49 Working Cash Factor	3.700%	3.700%	3.700%	3.700%
50 Gross-Up Factor	1.665	1.665	1.665	1.665
51 ROE Target	9.680%	9.680%	9.680%	9.680%
52 Grossed-Up COC	10.781%	10.781%	10.781%	10.781%
53 OPUC Fee Rate	0.3125%	0.3125%	0.313%	0.313%
Utility Income Taxes				
54 Book Revenues	1,712,597	48,954	42,993	1,804,544
55 Book Expenses	1,431,112	14,107	20,935	1,466,154
56 Interest Deduction	80,565	8,688	13,768	103,020
57 Production Deduction	-	-	-	-
58 Permanent Ms	(20,679)	(645)	(627)	(21,951)
59 Deferred Ms	(58,125)	6,196	71,740	19,811
60 Taxable Income	279,725	20,608	(62,823)	237,510
61 Current State Tax	21,298	1,569	(4,783)	18,084
62 State Tax Credits	(3,009)	-	-	(3,009)
63 Net State Taxes	18,289	1,569	(4,783)	15,075
64 Federal Taxable Income	261,436	19,039	(58,039)	222,436
65 Current Federal Tax	91,503	6,664	(20,314)	77,852
66 Federal Tax Credits	(28,929)	-	(19,757)	(48,686)
67 ITC Amort	-	-	-	-
68 Deferred Taxes	(23,221)	2,475	28,659	7,914
69 Total Income Tax Expense	57,642	10,708	(16,195)	52,155
70 Regulated Net Income	143,279			183,214
71 Check Regulated NI				183,214

ORDER NO. 14 422

Portland General Electric Company
2015 Revenue Requirement - Base Business
Dollars in $000s

									Total Increase:	Rev Req (47,617)	Percent -2.75%
	At Current Rates	Sep Load Forecast Delta	GRC Change for RROE	Proposed 2015	PRC Non-NVPC	PRC Update Non-NVPC	UM 1679 Depreciation Base	Subtotal	Non-NVPC Adjustments	NVPC Adjustments	Total Results
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1 Sales to Consumers	1,730,004	4,413	8,083	1,742,500	4,730	793	(11,737)	1,736,285	(36,657)	(12,829)	1,685,800
2 Sales for Resale	-			-				-	-	-	-
3 Other Revenues	23,521			23,521				23,521	2,277	-	25,798
4 Total Operating Revenues	1,753,525		8,083	1,766,021	4,730	793	(11,737)	1,759,806	(34,380)	(12,829)	1,712,597
5 Net Variable Power Costs	593,425			593,425		290		593,715	-	(12,356)	581,359
6 Production O&M (excludes Trojar	136,508			136,508	4,144	473		141,125	-	-	141,125
7 Trojan O&M	68			68				68	-	-	68
8 Transmission O&M	15,028			15,028				15,028	-	-	15,028
9 Distribution O&M	94,623			94,623				94,623	-	-	94,623
10 Customer & MBC O&M	70,202			70,202				70,202	(1,118)	-	69,084
11 Uncollectibles Expense	8,650		62	8,712	24	4	(59)	8,681	(122)	(60)	7,928
12 OPUC Fees	5,406		39	5,445	15	2	(37)	5,426	(81)	(40)	5,271
13 A&G, Ins/Bene., & Gen. Plant	149,418			149,418				149,418	(9,345)	-	140,073
14 Total Operating & Maintenance	1,073,328		102	1,073,430	4,182	770	(95)	1,078,287	(10,665)	(12,457)	1,054,559
15 Depreciation	245,908			245,908			(11,300)	234,608	-	-	234,608
16 Amortization	34,100			34,100				34,100	(1,228)	-	32,872
17 Property Tax	51,142			51,142				51,142	(126)	-	51,016
18 Payroll Tax	14,033			14,033				14,033	-	-	14,033
19 Other Taxes	1,835			1,835				1,835	-	-	1,835
20 Franchise Fees	43,270		313	43,583	118	20	(294)	43,427	(647)	(321)	42,190
21 Utility Income Tax	59,242		4,824	64,067	129	1	(14)	64,182	(6,525)	(15)	57,642
22 Total Operating Expenses & Taxe	1,522,859		5,238	1,528,097	4,429	790	(11,703)	1,521,614	(19,191)	(12,793)	1,488,754
23 **Utility Operating Income**	230,666		7,257	237,923	301	2	(34)	238,192	(15,189)	(36)	223,843
				237,923							223,843
24 **Average Rate Base**											
25 Avg. Gross Plant	7,293,364			7,293,364	3,700			7,297,064	(20,447)	-	7,276,617
26 Avg. Accum. Deprec. / Amort	(3,805,842)			(3,805,842)				(3,805,842)	(490)	-	(3,806,332)
27 Avg. Accum. Def Tax	(579,549)			(579,549)				(579,549)	(32,734)	-	(612,284)
28 Avg. Accum. Def ITC	-			-				-	-	-	-
29 **Avg. Net Utility Plant**	2,907,972		-	2,907,972	3,700	-	-	2,911,672	(53,671)	-	2,858,001
30 Misc. Deferred Debits	30,852			30,852				30,852	(1,500)	-	29,352
31 Operating Materials & Fuel	75,103			75,103				75,103	-	-	75,103
32 Misc. Deferred Credits	(11,740)			(11,740)				(11,740)	(45,500)	-	(57,240)
33 Working Cash	56,346		194	56,540	164	29	(433)	56,300	(710)	(473)	55,084
34 **Average Rate Base**	3,058,533		194	3,058,727	3,864	29	(433)	3,062,187	(101,381)	(473)	2,960,300
35 **Rate of Return**	7.542%			7.779%							7.562%
36 **Implied Return on Equity**	9.526%			10.000%							9.680%

ORDER NO.

	At Current Rates	Sep Load Forecast Delta	GRC Change for RROE	Proposed 2015	PRC Non-NVPC	PRC Update Non-NVPC	Depreciation Base	Subtotal	Non-NVPC Adjustments	NVPC Adjustments	Total Results
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
37 Effective Cost of Debt	5.557%		5.557%	5.557%	5.557%	5.557%	5.557%	5.557%	5.443%	5.443%	5.443%
38 Effective Cost of Preferred	0.000%		0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%
39 Debt Share of Cap Structure	50.000%		50.000%	50.000%	50.000%	50.000%	50.000%	50.000%	50.000%	50.000%	50.000%
40 Preferred Share of Cap Structure	0.000%		0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%
41 Weighted Cost of Debt	2.779%		2.779%	2.779%	2.779%	2.779%	2.779%	2.779%	2.722%	2.722%	2.722%
42 Weighted Cost of Preferred	0.000%		0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%
43 Equity Share of Cap Structure	50.000%		50.000%	50.000%	50.000%	50.000%	50.000%	50.000%	50.000%	50.000%	50.000%
44 State Tax Rate	7.614%		7.614%	7.614%	7.614%	7.614%	7.614%	7.614%	7.614%	7.614%	7.614%
45 Federal Tax Rate	35.000%		35.000%	35.000%	35.000%	35.000%	35.000%	35.000%	35.000%	35.000%	35.000%
46 Composite Tax Rate	39.949%		39.949%	39.949%	39.949%	39.949%	39.949%	39.949%	39.949%	39.949%	39.949%
47 Bad Debt Rate	0.500%		0.500%	0.500%	0.500%	0.500%	0.500%	0.500%	0.470%	0.470%	0.470%
48 Franchise Fee Rate	2.501%		2.501%	2.501%	2.501%	2.501%	2.501%	2.501%	2.501%	2.501%	2.501%
49 Working Cash Factor	3.700%		3.700%	3.700%	3.700%	3.700%	3.700%	3.700%	3.700%	3.700%	3.700%
50 Gross-Up Factor	1.665		1.665	1.665	1.665	1.665	1.665	1.665	1.665	1.665	1.665
51 ROE Target	10.000%		10.000%	10.000%	10.000%	10.000%	10.000%	10.000%	9.680%	9.680%	9.680%
52 Grossed-Up COC	11.105%		11.105%	11.105%	11.105%	11.105%	11.105%	11.105%	10.781%	10.781%	10.781%
53 OPUC Fee Rate	0.3125%		0.3125%	0.3125%	0.3125%	0.3125%	0.3125%	0.3125%	0.3125%	0.313%	0.313%
Utility Income Taxes											
54 Book Revenues	1,753,525		12,496	1,766,021	4,730	793	(11,737)	1,759,806	(34,380)	(12,829)	1,712,597
55 Book Expenses	1,463,517		414	1,464,031	4,301	789	(11,689)	1,457,432	(13,542)	(12,778)	1,431,112
56 Interest Deduction	84,981		5	84,987	107	1	(12)	85,083	(2,759)	(13)	80,565
57 Production Deduction	-			-				-	-		-
58 Permanent Ms	(20,679)			(20,679)				(20,679)	-		(20,679)
59 Deferred Ms	(26,469)			(26,469)				(26,469)	(31,657)		(58,125)
60 Taxable Income	252,074		12,076	264,151	322	2	(36)	264,439	13,578	(36)	279,725
61 Current State Tax	19,193		919	20,112	24	0	(3)	20,134	1,034	(3)	21,298
62 State Tax Credits	(3,009)			(3,009)				(3,009)	-		(3,009)
63 Net State Taxes	16,183		919	17,103	24	0	(3)	17,125	1,034	(3)	18,289
64 Federal Taxable Income	235,891		11,157	247,048	297	2	(33)	247,314	12,544	(35)	261,436
65 Current Federal Tax	82,562		3,905	86,467	104	1	(12)	86,560	4,390	(12)	91,503
66 Federal Tax Credits	(28,929)			(28,929)				(28,929)	-		(28,929)
67 ITC Amort	-		-	-					-		-
68 Deferred Taxes	(10,574)		0	(10,574)	0	0	0	(10,574)	(12,647)	-	(23,221)
69 Total Income Tax Expense	59,242		4,824	64,067	129	1	(14)	64,182	(7,222)	(15)	57,642
70 Regulated Net Income	145,684			152,936							143,279
71 Check Regulated NI				152,936							143,279

ORDER NO.

Portland General Electric Company
2015 Revenue Requirement - Port Westward 2
Dollars in $000s

	As Filed (2/13/2014)	DR 437 Update (5/12/2014)	Subtotal	First Settlement Impact	First Settlement Subtotal	Depreciation Study Update Impact	NVPC Adjustments	Total
1 Sales to Consumers	51,371	2,106	53,476	(1,085)	52,391	(4,991)	1,553	48,954
2 Sales for Resale	-	-	-		-	-	-	-
3 Other Revenues	-	-	-		-	-	-	-
4 Total Operating Revenues	51,871	2,106	53,476	(1,085)	52,391	(4,991)	1,553	48,954
5 Net Variable Power Costs	(1,213)	(792)	(2,006)	-	(2,006)	-	1,496	(510)
6 Production O&M (excludes Trojan)	1,479	-	1,479	-	1,479	-	-	1,479
7 Trojan O&M	-	-	-	-	-	-	-	-
8 Transmission O&M	-	-	-	-	-	-	-	-
9 Distribution O&M	-	-	-	-	-	-	-	-
10 Customer & MBC O&M	-	-	-	-	-	-	-	-
11 Uncollectibles Expense	257	11	267	(5)	246	(28)	7	230
12 OPUC Fees	161	7	167	(3)	164	(16)	5	153
13 A&G, Ins/Bene., & Gen. Plant	347	-	347	-	347	-	-	347
14 Total Operating & Maintenance	1,030	(775)	254	(8)	230	(39)	1,508	1,699
15 Depreciation	13,588	749	14,337	-	14,337	(4,846)	-	9,491
16 Amortization	-	-	-	-	-	-	-	-
17 Property Tax	1,434	229	1,663	-	1,663	-	-	1,663
18 Payroll Tax	30	-	30	-	30	-	-	30
19 Other Taxes	-	-	-	-	-	-	-	-
20 Franchise Fees	1,285	53	1,338	(27)	1,310	(125)	39	1,224
21 Utility Income Tax	10,186	855	11,040	(419)	10,700	6	2	10,708
22 Total Operating Expenses & Taxes	27,551	1,111	28,662	(455)	28,270	(5,004)	1,549	24,815
23 Utility Operating Income	23,819	995	24,815	(630)	24,121	13	4	24,139
24 Average Rate Base								
25 Avg. Gross Plant	310,417	12,809	323,227	-	323,227	-	-	323,227
26 Avg. Accum. Deprec. / Amort	(6,676)	(346)	(7,023)	-	(7,023)	1,223	-	(5,800)
27 Avg. Accum. Def Tax	1,457	293	1,750	-	1,750	(861)	-	890
29 Avg. Net Utility Plant	305,198	12,756	317,954	-	317,954	362	-	318,316
30 Misc. Deferred Debits	-	-	-	-	-	-	-	-
31 Operating Materials & Fuel	-	-	-	-	-	-	-	-
32 Misc. Deferred Credits	-	-	-	-	-	-	-	-
33 Working Cash	1,019	41	1,060	(17)	1,046	(185)	57	918
34 Average Rate Base	306,217	12,797	319,015	(17)	319,000	177	57	319,234
35 Rate of Return	7.779%		7.779%					7.562%
36 Implied Return on Equity	10.000%		10.000%					9.680%

ORDER NO.

37 Effective Cost of Debt	5.557%	5.557%	5.557%	5.443%	5.443%	5.443%	5.443%	5.443%
38 Effective Cost of Preferred	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%
39 Debt Share of Cap Structure	50.000%	50.000%	50.000%	50.000%	50.000%	50.000%	50.000%	50.000%
40 Preferred Share of Cap Structure	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%
41 Weighted Cost of Debt	2.779%	2.779%	2.779%	2.722%	2.722%	2.722%	2.722%	2.722%
42 Weighted Cost of Preferred	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%
43 Equity Share of Cap Structure	50.000%	50.000%	50.000%	50.000%	50.000%	50.000%	50.000%	50.000%
44 State Tax Rate	7.614%	7.614%	7.614%	7.614%	7.614%	7.614%	7.614%	7.614%
45 Federal Tax Rate	35.000%	35.000%	35.000%	35.000%	35.000%	35.000%	35.000%	35.000%
46 Composite Tax Rate	39.949%	39.949%	39.949%	39.949%	39.949%	39.949%	39.949%	39.949%
47 Bad Debt Rate	0.500%	0.500%	0.500%	0.470%	0.470%	0.470%	0.470%	0.470%
48 Franchise Fee Rate	2.501%	2.501%	2.501%	2.501%	2.501%	2.501%	2.501%	2.501%
49 Working Cash Factor	3.700%	3.700%	3.700%	3.700%	3.700%	3.700%	3.700%	3.700%
50 Gross-Up Factor	1.665	1.665	1.665	1.665	1.665	1.665	1.665	1.665
51 ROE Target	10.000%	10.000%	10.000%	9.680%	9.680%	9.680%	9.680%	9.680%
52 Grossed-Up COC	11.105%	11.105%	11.105%	10.781%	10.781%	10.781%	10.781%	10.781%
53 OPUC Fee Rate	0.313%	0.313%	0.313%	0.313%	0.313%	0.313%	0.313%	0.313%
Utility Income Taxes								
54 Book Revenues	51,371	2,106	53,476	(1,085)	52,391	(4,991)	1,553	48,954
55 Book Expenses	17,366	256	17,621	(36)	17,570	(5,010)	1,547	14,107
56 Interest Deduction	8,508	356	8,864	(0)	8,682	5	2	8,688
57 Production Deduction	-	-	-	-	-	-	-	-
58 Permanent Ms	-	(645)	(645)	-	(645)	-	-	(645)
59 Deferred Ms	-	1,350	1,350	-	1,350	4,847	-	6,196
60 Taxable Income	25,496	790	26,287	(1,049)	25,435	(4,832)	5	20,608
61 Current State Tax	1,941	60	2,001	(80)	1,937	(368)	0	1,569
62 State Tax Credits	-	-	-	-	-	-	-	-
63 Net State Taxes	1,941	60	2,001	(80)	1,937	(368)	0	1,569
64 Federal Taxable Income	23,555	730	24,285	(969)	23,499	(4,464)	4	19,039
65 Current Federal Tax	8,244	255	8,500	(339)	8,225	(1,563)	1	6,664
66 Federal Tax Credits	-	-	-	-	-	-	-	-
67 ITC Amort	-	-	-	-	-	-	-	-
68 Deferred Taxes	-	539	539	-	539	1,936	-	2,475
69 Total Income Tax Expense	10,186	855	11,040	(419)	10,700	5	2	10,708
70 Regulated Net Income								
71 Check Regulated NI								

Portland General Electric Company
2015 Revenue Requirement - Tucannon River Wind Farm
Dollars in $000s

	As Filed (2/13/2014)	DR 443 Update (5/12/2014)	Subtotal	First Settlement Impact	First Settlement Subtotal	Depreciation Study Update Impact	NVPC Adjustments	Total
1 Sales to Consumers	46,663	919	47,582	(1,705)	45,877	(3,323)	440	42,993
2 Sales for Resale	-	-	-		-	-	-	-
3 Other Revenues	-	-	-		-	-	-	-
4 Total Operating Revenues	46,663	919	47,582	(1,705)	45,877	(3,323)	440	42,993
5 Net Variable Power Costs	(16,423)	(2,542)	(18,965)	-	(18,965)	-	423	(18,541)
6 Production O&M (excludes Trojan)	8,473	(1,003)	7,470	-	7,470	-	-	7,470
7 Trojan O&M	-	-	-	-	-	-	-	-
8 Transmission O&M	-	-	-	-	-	-	-	-
9 Distribution O&M	-	-	-	-	-	-	-	-
10 Customer & MBC O&M	-	-	-	-	-	-	-	-
11 Uncollectibles Expense	233	5	238	(8)	216	(16)	2	202
12 OPUC Fees	146	3	149	(5)	143	(10)	1	134
13 A&G, Ins/Bens., & Gen. Plant	435	-	435	-	435	-	-	435
14 Total Operating & Maintenance	(7,136)	(3,537)	(10,673)	(13)	(10,701)	(26)	427	(10,300)
15 Depreciation	23,671	2,876	26,547	-	26,547	(3,338)	-	23,209
16 Amortization	-	-	-	-	-	-	-	-
17 Property Tax	6,943	-	6,943	-	6,943	-	-	6,943
18 Payroll Tax	7	-	7	-	7	-	-	7
19 Other Taxes	-	-	-	-	-	-	-	-
20 Franchise Fees	1,167	23	1,190	(43)	1,147	(83)	11	1,075
21 Utility Income Tax	(16,482)	788	(15,694)	(659)	(16,232)	37	1	(16,195)
22 Total Operating Expenses & Taxes	8,171	149	8,320	(715)	7,712	(3,410)	438	4,740
23 **Utility Operating Income**	38,492	770	39,261	(991)	38,164	87	1	38,253
24 **Average Rate Base**								
25 Avg. Gross Plant	510,037	14,579	524,617	-	524,617	-	-	524,617
26 Avg. Accum. Deprec. / Amort	(11,834)	(1,534)	(13,368)	-	(13,368)	1,764	-	(11,604)
27 Avg. Accum. Def Tax	(3,660)	(3,154)	(6,815)	-	(6,815)	(485)	-	(7,300)
29 **Avg. Net Utility Plant**	494,543	9,891	504,434	-	504,434	1,279	-	505,713
30 Misc. Deferred Debits	-	-	-	-	-	-	-	-
31 Operating Materials & Fuel	-	-	-	-	-	-	-	-
32 Misc. Deferred Credits	-	-	-	-	-	-	-	-
33 Working Cash	302	6	308	(26)	285	(126)	16	175
34 **Average Rate Base**	494,845	9,897	504,742	(26)	504,719	1,152	16	505,888
35 **Rate of Return**	7.779%				7.562%			7.562%
36 **Implied Return on Equity**	10.000%				9.680%			9.680%

ORDER NO.

37 Effective Cost of Debt	5.557%	5.557%	5.557%	5.443%	5.443%	5.443%	5.443%	5.443%
38 Effective Cost of Preferred	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%
39 Debt Share of Cap Structure	50.000%	50.000%	50.000%	50.000%	50.000%	50.000%	50.000%	50.000%
40 Preferred Share of Cap Structure	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%
41 Weighted Cost of Debt	2.779%	2.779%	2.779%	2.722%	2.722%	2.722%	2.722%	2.722%
42 Weighted Cost of Preferred	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%
43 Equity Share of Cap Structure	50.000%	50.000%	50.000%	50.000%	50.000%	50.000%	50.000%	50.000%
44 State Tax Rate	7.614%	7.614%	7.614%	7.614%	7.614%	7.614%	7.614%	7.614%
45 Federal Tax Rate	35.000%	35.000%	35.000%	35.000%	35.000%	35.000%	35.000%	35.000%
46 Composite Tax Rate	39.949%	39.949%	39.949%	39.949%	39.949%	39.949%	39.949%	39.949%
47 Bad Debt Rate	0.500%	0.500%	0.500%	0.470%	0.470%	0.470%	0.470%	0.470%
48 Franchise Fee Rate	2.501%	2.501%	2.501%	2.501%	2.501%	2.501%	2.501%	2.501%
49 Working Cash Factor	3.700%	3.700%	3.700%	3.700%	3.700%	3.700%	3.700%	3.700%
50 Gross-Up Factor	1.665	1.665	1.665	1.665	1.665	1.665	1.665	1.665
51 ROE Target	10.000%	10.000%	10.000%	9.680%	9.680%	9.680%	9.680%	9.680%
52 Grossed-Up COC	11.105%	11.105%	11.105%	10.781%	10.781%	10.781%	10.781%	10.781%
53 OPUC Fee Rate	0.313%	0.313%	0.313%	0.313%	0.313%	0.313%	0.313%	0.313%
Utility Income Taxes								
54 Book Revenues	46,663	919	47,582	(1,705)	45,877	(3,323)	440	42,993
55 Book Expenses	24,653	(638)	24,015	(56)	23,944	(3,447)	438	20,935
56 Interest Deduction	13,749	275	14,024	(1)	13,736	31	0	13,768
57 Production Deduction	-	-	-	-	-	-	-	-
58 Permanent Ms	-	(627)	(627)	-	(627)	-	-	(627)
59 Deferred Ms	-	68,402	68,402	-	68,402	3,338	-	71,740
60 Taxable Income	8,260	(66,493)	(58,232)	(1,649)	(59,579)	(3,245)	1	(62,823)
61 Current State Tax	629	(5,063)	(4,434)	(126)	(4,536)	(247)	0	(4,783)
62 State Tax Credits	-	-	-	-	-	-	-	-
63 Net State Taxes	629	(5,063)	(4,434)	(126)	(4,536)	(247)	0	(4,783)
64 Federal Taxable Income	7,631	(61,430)	(53,799)	(1,523)	(55,043)	(2,998)	1	(58,039)
65 Current Federal Tax	2,671	(21,501)	(18,829)	(533)	(19,265)	(1,049)	0	(20,314)
66 Federal Tax Credits	(19,782)	25	(19,757)	-	(19,757)	-	-	(19,757)
67 ITC Amort	-	-	-	-	-	-	-	-
68 Deferred Taxes	-	27,326	27,326	-	27,326	1,333	-	28,659
69 Total Income Tax Expense	(16,482)	788	(15,694)	(659)	(16,232)	37	1	(16,195)
70 Regulated Net Income								
71 Check Regulated NI								

TABLE 4
PORTLAND GENERAL ELECTRIC
ESTIMATED EFFECT ON CONSUMERS' TOTAL ELECTRIC BILLS
2015

CATEGORY	RATE SCHEDULE	CUSTOMERS (Forecast SSEP14E15)	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	742,306	7,554,568	$875,267,741	$882,889,159	$7,621,418	0.9%
Employee Discount				($902,555)	($913,107)	($10,553)	
Subtotal				$874,365,187	$881,976,052	$7,610,865	0.9%
Outdoor Area Lighting	15	0	16,308	$3,756,448	$3,730,293	($26,155)	-0.7%
General Service <30 kW	32	89,748	1,580,865	$174,483,415	$175,888,599	$1,405,184	0.8%
Opt. Time-of-Day G.S. >30 kW	38	540	38,680	$5,155,480	$5,376,639	$221,159	4.3%
Irrig. & Drain. Pump. < 30 kW	47	3,152	20,552	$3,275,376	$3,629,732	$354,356	10.8%
Irrig. & Drain. Pump. > 30 kW	49	1,349	61,803	$6,876,851	$7,596,021	$719,170	10.5%
General Service 31-200 kW	83	10,955	2,762,661	$250,499,394	$253,234,156	$2,734,762	1.1%
General Service 201-4,000 kW							
Secondary	85-S	1,254	2,436,608	$197,066,468	$198,644,523	$1,578,055	0.8%
Primary	85-P	192	688,718	$51,610,939	$52,467,305	$856,366	1.7%
Schedule 89 > 4 MW							
Primary	89-P	14	755,381	$48,999,039	$49,632,440	$633,401	1.3%
Subtransmission	89-T	5	204,263	$14,047,327	$13,977,471	($69,856)	-0.5%
Schedule 90	90-P	4	1,374,409	$83,945,130	$84,672,378	$727,248	0.9%
Street & Highway Lighting	91/95	205	85,227	$17,526,080	$17,562,384	$36,304	0.2%
Traffic Signals	92	17	3,327	$265,262	$267,424	$2,163	0.8%
COS TOTALS		849,741	17,583,360	$1,731,874,396	$1,748,655,416	$16,781,020	1.0%
Direct Access Service 201-4,000 kW							
Secondary	485-S	160	433,145	$10,931,898	$9,004,815	($1,927,083)	
Primary	485-P	42	243,686	$6,398,704	$5,478,862	($919,842)	
Direct Access Service > 4 MW							
Secondary	489-S	1	14,239	$498,144	$441,909	($56,235)	
Primary	489-P	10	540,845	$8,091,684	$6,391,271	($1,700,413)	

Subtransmission	489-T	3	307,163	$3,935,566	$2,827,165	($1,108,401)	
DIRECT ACCESS TOTALS		216	1,539,100	$29,855,996	$24,144,022	($5,711,973)	
COS AND DA CYCLE TOTALS		849,957	19,122,460	$1,761,730,391	$1,772,799,438	$11,069,047	0.6%

TABLE 1
PORTLAND GENERAL ELECTRIC
ESTIMATED EFFECT ON CONSUMERS' TOTAL ELECTRIC BILLS
2015

		Forecast SSEP14E15		TOTAL ELECTRIC BILLS CURRENT	TOTAL ELECTRIC BILLS PROPOSED	Change	
CATEGORY	RATE SCHEDULE	CUSTOMERS	MWH SALES	w/ Sch. 122a, 125	w/ Sch. 122a, 125	AMOUNT	PCT.
Residential	7	742,306	7,554,568	$878,881,705	$905,167,160	$26,285,454	3.0%
Employee Discount				($928,911)	($957,297)	($28,386)	
Subtotal				$877,952,794	$904,209,863	$26,257,068	3.0%
Outdoor Area Lighting	15	0	16,308	$3,653,155	$3,639,803	($13,353)	-0.4%
General Service <30 kW	32	89,748	1,580,865	$170,135,911	$173,020,518	$2,884,607	1.7%
Opt. Time-of-Day G.S. >30 kW	38	540	38,580	$4,932,830	$5,202,813	$269,983	5.5%
Irrig. & Drain. Pump. < 30 kW	47	3,152	20,552	$3,258,505	$3,649,423	$390,918	12.0%
Irrig. & Drain. Pump. > 30 kW	49	1,349	61,803	$6,896,612	$7,724,455	$827,844	12.0%
General Service 31-200 kW	83	10,955	2,762,651	$239,182,908	$245,585,794	$6,402,886	2.7%
General Service 201-4,000 kW							
Secondary	85-S	1,254	2,436,608	$187,404,173	$192,110,928	$4,706,756	2.5%
Primary	85-P	192	688,718	$49,820,532	$51,687,641	$1,867,109	3.7%
Schedule 89 > 4 MW							
Primary	89-P	14	755,381	$47,729,998	$49,488,917	$1,758,919	3.7%
Subtransmission	89-T	5	204,263	$13,706,209	$13,936,618	$230,410	1.7%
Schedule 90	90-P	4	1,374,409	$81,636,122	$84,383,752	$2,747,630	3.4%
Street & Highway Lighting	91/95	205	85,227	$16,903,923	$17,010,113	$106,190	0.6%
Traffic Signals	92	17	3,327	$251,189	$257,210	$6,022	2.4%
COS TOTALS		849,741	17,583,360	$1,703,464,861	$1,751,907,849	$48,442,988	2.8%
Direct Access Service 201-4,000 kW							
Secondary	485-S	160	433,145	$10,020,294	$8,726,756	($1,293,538)	
Primary	485-P	42	243,686	$6,013,047	$5,432,542	($580,505)	
Direct Access Service > 4 MW							
Secondary	489-S	1	14,239	$493,730	$455,294	($38,436)	
Primary	489-P	10	540,845	$7,924,022	$6,883,440	($1,040,581)	

ORDER NO.

Subtransmission	489-T	3	307,183	$3,840,339	$3,100,558	($739,781)	
DIRECT ACCESS TOTALS		216	1,539,100	$28,291,431	$24,598,589	($3,692,842)	
COS AND DA CYCLE TOTALS		849,957	19,122,460	$1,731,756,293	$1,776,506,439	$44,750,146	2.6%