Portland General Electric Company
Legal Department
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Douglas C. Tingey
Associate General Counsel

September 18, 2017

Via Electronic Filing

Oregon Public Utility Commission
Attention: Filing Center
PO Box 1088
Salem, OR 97308-1088

Re: UE 319- PGE's Request for a General Rate Revision

Attention Filing Center:

Enclosed for filing in the above-referenced docket is the **Motion to Admit Partial Stipulation and Joint Testimony**, the **Partial Stipulation,** and **Joint Testimony in Support of 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, Walmart Stores, Inc. and Sam's West, Inc, Fred Meyer Stores and Quality Food Centers, Division of the Kroger Co., and Small Business Utility Advocates. These documents are being filed by electronic mail with the Filing Center.

Thank you in advance for your assistance.

Sincerely,

Doug Tingey
Associate General Counsel

DT: lh
encl.

BEFORE THE PUBLIC UTILITY COMMISSION OF OREGON

UE 319

In the Matter of PORTLAND GENERAL ELECTRIC COMPANY Request for a General Rate Revision.	**MOTION TO ADMIT PARTIAL STIPULATION AND JOINT TESTIMONY**

Pursuant to OAR 860-001-0350(7), Portland General Electric Company ("PGE") moves for admission of the attached Partial Stipulation, submitted herewith as evidence in this proceeding. PGE also moves that the following testimony and exhibits in support of that Partial Stipulation be admitted into the record of this proceeding:

Testimony	Witness(es)
Joint Testimony in Support of Partial Stipulation/200-202	Marianne Gardner/OPUC Neal Townsend/Kroger Bob Jenks/CUB Bradley R. Mullins/ICNU Stefan Brown/PGE

The affidavits attesting to the truth and accuracy of the testimony will be submitted soon.

DATED this 18th day of September, 2017.

Respectfully submitted,

Douglas C. Tingey, OSB No. 044366
Assistant General Counsel
Portland General Electric Company
121 SW Salmon Street, 1WTC1301
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BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

UE 319

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 Oregon Citizens' Utility Board ("CUB"), the Industrial Customers of Northwest Utilities ("ICNU"), Fred Meyer Stores and Quality Food Centers, Division of The Kroger Co. ("Kroger"), Wal-Mart Stores Inc. and Sam's West, Inc. ("Walmart"), and the Small Business Utility Advocates ("SBUA") (collectively, the "Stipulating Parties").

PGE filed this general rate case on February 28, 2017. The filing included fourteen separate pieces of testimony and exhibits. PGE also provided to Staff and other parties voluminous work papers in support of its filing. Since that time, Staff and intervening parties have analyzed PGE's filing and work papers, and submitted more than 800 data requests obtaining additional information. Two schedules were set by the Administrative Law Judge in this matter: one for net variable power cost ("NVPC") issues, and the other for general rate case issues. All NVPC issues have been settled, and a NVPC Stipulation has been filed with the Commission. All parties had the opportunity to file testimony regarding non-power cost issues on June 16, 2017. Settlement conferences were held on July 6, 7, 11, and 24. Some issues were settled prior to PGE filing Reply Testimony on July 18, 2017. An additional settlement conference was held on August 3. The Stipulating Parties participated in these numerous settlement discussions. Calpine Solutions also participated in settlement discussions, and does not object to this Partial Stipulation. No other parties participated in the discussions. As a result of those discussions, the Stipulating Parties have reached a compromise settlement of all remaining issues in this docket except one. The following terms apply to adjustments to be made relative to PGE's filed case.

TERMS OF PARTIAL STIPULATION

1. This Stipulation resolves all remaining issues in this docket except CUB's proposal for the allocation of costs and benefits for energy efficiency funded under Senate Bill 838 (2007).

2. Uncollectibles (S-1). PGE will reduce its uncollectible rate to 0.3431% based on a three-year average of actual write-offs for calendar years 2014-2016.

3. OPUC Fees (S-2). PGE will apply a 0.3211% OPUC Fee rate based on a reduced gross-up factor to account for sales for resale. PGE will also reduce the OPUC Fee amount to reflect a 0.3000% rate on the incremental revenue requirement of this case.

4. Interest Synchronization (S-3). PGE and Staff agree that their respective calculations align. There is no change to revenue requirement.

5. IT Cybersecurity Amortization (S-4). PGE will provide Staff with more information on segregating and identifying development costs. There is no change to revenue requirement.

6. ADIT (S-5) (IN 8-13). In settlement of these accumulated deferred income tax (ADIT) related issues PGE will reduce rate base by approximately $27.8 million.

7. Working Cash (S-6). PGE and Staff agree that their respective calculations align, and PGE will continue to use a 3.628% working cash factor.

8. Major Storms (S-7). PGE will increase the annual storm accrual to $2.6 million as stated in PGE Exhibit 800 and withdraws its request in this docket for a balancing account for Level III storm costs.

9. Escalation (S-8). There will be no adjustment for this issue.

10. Wages and Salaries, Incentives, and FTEs (S-9).

    a. O&M expense will be reduced by $2,425,018 and Capital will be reduced by $1,051,773 relative to PGE's filed case in order to settle wages and salaries and incentive costs. These amounts are calculated by removing PGE's request related to Officer incentives and by using Staff's three-year wages and salaries model, with escalation rates averaged between Staff's and PGE's filed escalation rates for non-bargaining FTEs and the contracted escalation rates for union FTEs. The Stipulating Parties further agree not to place CET benefit loadings into the CET deferral.

    b. The Stipulating Parties agree to a non-specified revenue requirement reduction of $6.0 million to settle all FTE issues. Additionally, the Stipulating Parties agree to a $0.1 million expense reduction to settle Administrative and General Contractor costs.

11. CET Deferral and Amortization (S-28). The remainder of CET deferral costs for 2014-2016 (as of year-end 2017) and PGE's forecasted CET O&M costs for 2017 and 2018 will be moved from base rates into a supplemental schedule. The supplemental schedule will amortize the 2014-2016 deferral balance and the 2017 and 2018 forecasted costs over five years beginning January 1, 2018 with interest accruing at the modified blended treasury rate.

12. Insurance (S-10). D&O insurance costs will be reduced by $272,000.

13. Medical Benefits (S-11) (IN-5). PGE will reduce medical benefit costs by approximately \$1.2 million to address ICNU's issue regarding cost escalation.

14. Cost of Capital (S-13) (IN-1). For determining rates in this case:

a. The Cost of Long-Term (LT) Debt will be set at a ceiling of 5.203% plus a minimal adjustment for fees. Any changes to debt in 2017 that reduce PGE's overall cost of LT Debt below 5.203% will be reflected in PGE's final revenue requirement update. Any subsequent changes through June 30, 2018 that reduce PGE's overall cost of LT Debt below 5.203% will be reflected through a supplemental tariff filing.

b. The Return on Equity will be 9.50%.

c. The assumed debt to equity ratio will be 50/50.

15. Post Retirement Costs/Pensions (S-14). PGE withdraws its accounting treatment language request, and will capitalize pension and post-retirement plans in a manner consistent with PGE's method prior to the issuance of FASB ASU 2017-07. This results in a cost reduction of approximately \$1.55 million.

16. AFUDC (S-15). In September or October 2017, PGE will hold a workshop with Staff and other parties to review the FERC-specified AFUDC formula and PGE's calculations/transactions.

17. Fee Free Bank Card (S-16). PGE will set the per-transaction rate at the \$1.54 level determined in Docket No. UE 294. PGE also agrees with Staff's revised adoption rate of 10.84%. These result in a cost reduction of \$503,000.

18. Load Forecasting (S-17 and S-31).

a. The Stipulating Parties agree to the use of PGE's load forecast model with the following adjustments for this case only:

i. Use of a 15-year average weather assumption; and

ii. A 25% reduction to PGE's outboard energy efficiency decrement to its 2018 load forecast.

b. No additional variable or structural changes will be made to PGE's model within this case.

c. PGE will conduct a workshop before year-end 2017 on load forecasting. PGE will provide Staff its evaluation of non-stationarity in its models, and any necessary corrections, before the second quarter of 2018.

19. Other Revenue and Low Services (S-18 and S-30). In settlement of both of these issues, the Stipulating Parties agree:

a. PGE will increase its Other Revenue forecast and reduce its O&M expense by a combined total of $1.5 million.

b. There will be a ten-year inspection cycle and two-year correction cycle for service connections with point of attachment (POA) below eight feet and between eight and ten feet.

c. Beginning January 1, 2018 and until the next general rate case, PGE will include $1,583,742/year in rates for the Low Clearance program plus the loaded labor expenses associated with the Low Clearance program FTEs (i.e., two fully loaded FTEs).

d. PGE agrees to provide an annual report containing the following information:

i. The annual cost of the Low Clearance program;

ii. The amount of Low Clearance program costs capitalized, if any;

iii. The number of service connections inspected for POA height;

iv. The number of inspected service connections found to have POA/POW (point of weatherhead) below eight feet;

v. The number of inspected service connections found to have POW between eight and ten feet;

vi. The number of sub-eight-foot connections corrected and the cost of correction; and

vii. The number of eight to ten-foot connections corrected and the cost of correction.

e. PGE agrees to modify the portions of testimony agreed to with Staff related to low service connects.

f. Staff agrees to withdraw its recent data requests (DRs) dealing with Low Service Connects (i.e., OPUC DRs 698-708).

g. PGE will make best efforts to correct low service connections below eight feet and above eight feet in approximately the same ratio as discovered in inspections.

20. Carty Generating Station (S-19). For the purposes of this rate case, PGE will remove the AFUDC calculated for the Carty Generating Station from mid-May to July 29, 2016. This results in a reduction to rate base of approximately \$7.7 million. To maintain compliance with IRS normalization rules (see PGE Exhibit 200, Section III), PGE will also reduce ADIT by approximately \$1.0 million to coincide with the revised plant amount.

21. Major Maintenance Accruals (MMA's) (S-20). PGE will file deferred accounting applications associated with MMAs every year beginning on January 1, 2018. The Colstrip MMA will be calculated using a three-year moving average, which results in a \$244,000 increase to PGE's production O&M costs.

22. Generation O&M (S-21). Generation O&M expense will be reduced by \$90,000.

23. Affiliated Interests (S-22). PGE will hold a workshop prior to its next general rate case to address Staff's concerns regarding allocation factors.

24. Customer Services (S-23). PGE will reduce non-labor customer service costs by $300,000.

25. Environmental Licensing (S-24). No adjustment for this issue. On August 11, PGE provided additional information to Staff to support this position, including work papers demonstrating that the costs requested in this case are lower than 2016 costs exclusive of Portland Harbor related costs.

26. R&D and Memberships (S-25).

    a. PGE will reduce its request by $800,000 to $2.2 million, which includes administrative costs. To address concerns regarding R&D projects, PGE will file a report in October of each year regarding prospective R&D projects and will also continue to file the annual retrospective report as stipulated in UE 294. PGE will continue the historic treatment of administrative costs.

    b. Membership costs will be reduced by $111,680.

27. Depreciation (S-26) (IN-4).

    a. PGE will provide a reconciliation in an electronic spreadsheet of the following items:

        i. The final depreciation expense amount in PGE's revenue requirement (including the Carty component and exclusive of the plant adjustments agreed to in this stipulation); and

        ii. The depreciation amount as determined by the UM 1809 depreciation study and based on: 1) plant in service at year end 2017; and 2) the adjusted annualization of 2017 depreciation expense to reflect the declining balance impact during 2018. The reconciliation will include the same level of detail as the summary calculations in Docket No. UM 1809.

b. PGE will remove approximately $7.3 million from depreciation expense associated with the asset retirement obligation.

c. PGE will reduce depreciation expense by approximately $8.2 million to reflect the settlement reached in the depreciation study, Docket No. UM 1809. To maintain compliance with IRS normalization rules (see PGE Exhibit 200, Section III), PGE will also reduce accumulated depreciation by approximately $8.2 million and increase ADIT by approximately $1.1 million to coincide with the revised depreciation expense.

28. <u>Plant in Service (S-27), PTC ADIT (IN-7), Distribution O&M (S-12)</u>.

a. The Stipulating Parties agree to a non-specified rate base reduction of $50 million to resolve these three issues.

b. The Stipulating Parties agree they are free to raise issues related to PGE's production tax credit (PTC) carryforwards in future proceedings.

c. Regarding Plant in Service:

i. PGE agrees to file attestations for six large projects scheduled to close to plant in the second half of 2017.

ii. If any of these projects do not come into service prior to January 1, 2018, PGE will remove the amounts not in service from base rates effective January 1, 2018. If, due to timing of the projects, PGE is unable to remove these amounts from rates prior to January 1, 2018, PGE will refund to customers the amounts recovered.

iii. PGE agrees to answer information requests from all parties related to plant-in-service included in rates through this general rate case.

iv. PGE agrees to file a report by February 15, 2018 showing: (1) a list of capital projects that were planned for 2017 as represented in PGE's Second Supplemental Response to DR No. 139, dated August 2, 2017, (2) a list of capital projects transferred to plant in 2017, (3) a forecast amount for each capital project, (4) the actual amount for each capital project, (5) the variance amount between forecast and actual expenditures.

29. Legal Fees (S-29). Staff's concerns were resolved through a data request and this issue is withdrawn.

30. Ratespread and Rate Design. The Stipulating Parties agree as follows:

a. The Schedule 7 Basic Charge will be $11.00 per month.

b. The Schedule 32 Basic Charge will be increased by one dollar per month for single and three-phase service respectively.[1]

c. Schedule 110 prices will be reduced to begin amortizing the excess balance effective January 1, 2018.

d. Lighting schedule prices will be updated to reflect the Cost of Capital adopted by the Commission in this docket.

e. PGE will begin amortization of the Schedules 5 & 6 balancing accounts effective January 1, 2018.

f. In PGE's next general rate case, PGE will either propose Schedule 32 demand charges, or state why it proposes to keep volumetric prices instead.

[1] SBUA's participation has been limited in this docket and SBUA input regarding this Partial Stipulation is limited to this provision. SBUE takes no position on other provisions of this Partial Stipulation.

g. Adopt Staff's Schedule 7 TOU proposal, and keep Schedule 38 in its present form. Additionally, PGE will report annually to Staff and other interested parties on Schedule 38 customers' average use per customer by month and the average range of load factor.

h. Eliminate the Customer Impact Offset (CIO), except for the lighting schedules. Parties agree to keep open the option of revisiting the customer impact offset for purposes of resolution of the EE issue.

i. With respect to the Schedule 90 load following credit, accept ICNU's proposal of crediting Schedule 90 (1.13 mills/kWh + 0.25 mills/kWh for 150 MW), and allocating the costs of this credit to other cost of service rate schedules. However, the Schedule 89 surcharge will not exceed 0.57 mills/kWh. The Schedule 90 additional credit will be reduced accordingly if the Schedule 89 surcharge otherwise exceeds the 0.57 mills/kWh.

j. Accept PGE allocations for advanced metering infrastructure meters, the customer information system, and meter data management system.

k. Re-functionalize storage costs of approximately $300,000 to generation from customer.

l. The Stipulating Parties request that the Commission open an investigative docket to address the appropriate functionalization and/or allocation of PGE smart grid costs.

m. Set the Schedule 85 secondary/primary Facility Capacity Charge price differential of $0.25/kW-month. In addition, in its next GRC, PGE will examine the test period marginal capital costs of primary and secondary Distribution Facilities in its current design standards and the maintenance costs contained in FERC accounts 583, 584, 593, and 594 and estimate the amounts attributable to secondary voltage service conductors, secondary voltage conductors, and primary voltage conductors.

31. 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.

32. 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.

33. 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.

34. 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.

35. 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.

36. 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 _______ day of September, 2017.

PORTLAND GENERAL ELECTRIC COMPANY

STAFF OF THE PUBLIC UTILITY COMMISSION OF OREGON

OREGON CITIZENS' UTILITY BOARD

INDUSTRIAL CUSTOMERS OF NORTHWEST UTILITIES

THE KROGER CO.

WALMART STORES, INC. AND SAM'S WEST, INC.

SMALL BUSINESS UTILITY ADVOCATES

DATED this 18th day of September, 2017.

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.

WALMART STORES, INC. AND SAM'S WEST, INC.

SMALL BUSINESS UTILITY ADVOCATES

DATED this 15th day of September, 2017.

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.

WALMART STORES, INC. AND
SAM'S WEST, INC.

SMALL BUSINESS UTILITY ADVOCATES

DATED this 15th day of September, 2017.

PORTLAND GENERAL ELECTRIC
COMPANY

STAFF OF THE PUBLIC UTILITY
COMMISSION OF OREGON

CITIZENS' UTILITY BOARD
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DATED this 18 day of September, 2017.

PORTLAND GENERAL ELECTRIC COMPANY

STAFF OF THE PUBLIC UTILITY COMMISSION OF OREGON

OREGON CITIZENS' UTILITY BOARD

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THE KROGER CO.

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SMALL BUSINESS UTILITY ADVOCATES

PORTLAND GENERAL ELECTRIC
COMPANY

STAFF OF THE PUBLIC UTILITY
COMMISSION OF OREGON

OREGON CITIZENS' UTILITY BOARD
~~OF OREGON~~

INDUSTRIAL CUSTOMERS OF
NORTHWEST UTILITIES

THE KROGER CO.

Vicki M. Baldwin

WALMART STORES, INC. AND
SAM'S WEST, INC.

SMALL BUSINESS UTILITY ADVOCATES

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.

WALMART STORES, INC. AND SAM'S WEST, INC.

s/ Diane Henkels

SMALL BUSINESS UTILITY ADVOCATES

BEFORE THE PUBLIC UTILITY COMMISSION OF THE STATE OF OREGON

UE 319

PORTLAND GENERAL ELECTRIC COMPANY

Joint Testimony in Support of Partial Stipulation

Marianne Gardner
Neal Townsend
Bob Jenks
Bradley Mullins
Stefan Brown

September 18, 2017

Table of Contents

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 Division at the Public Utility Commission of Oregon (OPUC). My qualifications appear in OPUC Exhibit 401.

My name is Neal Townsend. I am Principal with Energy Strategies, LLC and am testifying on behalf of Fred Meyer Stores and Quality Food Centers (Fred Meyer), Divisions of The Kroger Co. My qualifications appear in FM Exhibit 100.

My name is Bob Jenks. I am the Executive Director of the Oregon Citizens' Utility Board (CUB). My qualifications appear in CUB Exhibit 101.

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

My name is Stefan Brown. I am Manager of Regulatory Affairs in Portland General Electric Company's (PGE's) Rates and Regulatory Affairs Department. My qualifications appear in Section IV below.

Q. What is the purpose of your testimony?

A. Our purpose is to describe the September XX, 2017 Partial Stipulation (the Stipulation) reached among the OPUC Staff (Staff), CUB, ICNU, Fred Meyer, Walmart, the Small Business Utility Advocates (SBUA), and PGE (collectively, the Stipulating Parties or Parties) regarding all revenue requirement, marginal cost of service, and pricing issues in this docket (UE 319). Calpine participated in the settlement discussions, and while they are not a party to the Stipulation, they do not oppose the Stipulation. While there are other parties to this case, we are not aware of any who oppose this Stipulation.

Q. What is the basis for the Stipulation?

A. PGE filed this general rate case on February 28, 2017. During the next four to five months, PGE responded to more than 800 data requests from Staff, CUB, ICNU, and other parties. On May 5, parties held a workshop to discuss issues and review various revenue requirement topics. Staff, CUB, ICNU, Fred Meyer, and Walmart submitted opening testimony on June 16, 2017. The Parties subsequently held settlement discussions on July 6, 7, and 11, 2017. At the July 11 meeting, Parties reached an agreement on a number of issues deemed reasonable for settlement. PGE then filed reply testimony on July 18, 2017. Following this, the Parties held additional settlement discussions July 24 and August 3, 2017, where parties reached agreement on all but one outstanding issue, CUB's proposal for the allocation of costs and benefits for energy efficiency funded under Senate Bill 838 (2007), which they raised in CUB Exhibit 100.

Q. Please summarize the agreement contained in the revenue requirement portion of the Stipulation.

A. The Stipulation represents the settlement of all revenue requirement issues, except net variable power costs, which were previously settled. A copy of the Stipulation is provided as Exhibit 201. Table 1 below summarizes the settled issues with a short description. Exhibit 202 provides an updated revenue requirement incorporating the results of this Stipulation, the previously filed stipulation regarding PGE's 2018 net variable power cost forecast (NVPC), plus the latest NVPC and load forecasts.

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 2017; and
- Power cost forecast to be finalized on November 15, 2017.

Table 1
(Stipulated issues with approximate adjustments)

Issue No.	Category	Description
S-1	Uncollectibles	Decrease Uncollectibles rate from 0.370% to 0.3431%.
S-2	OPUC Fees	Apply a 0.3211% OPUC Fee rate based on a reduced gross up factor to account for sales for resale. Reduce the OPUC Fee amount to reflect a 0.3000% rate on the incremental revenue requirement of this case.
S-3	Interest Synchronization	PGE and Staff agree that their respective calculations align. No change to revenue requirement.
S-4	IT Cybersecurity Amortization	PGE will provide Staff with more information on segregating and identifying development costs.
S-5, IN-8 through IN-13	ADIT	Reduce rate base by approximately $27.8 million.
S-6	Working Cash	Continue to use a 3.628% working cash factor.
S-7	Major Storms	Increase the annual storm accrual to $2.6 million. PGE will withdraw its request for a balancing account for Level III storm costs.
S-8	Escalation	No adjustment.
S-9	Labor Costs	Reduce expense by $2.525 million. Reduce rate base by $1.052 million. Reduce Revenue Requirement by $6 million.
S-28	CET Deferral and Amortization	Move remainder of 2014-2016 deferred costs and forecasted 2017-2018 CET O&M costs from base rates into a supplemental schedule. Amortize supplemental schedule over five years beginning January 1, 2018 with interest accruing at the modified blended treasury rate.
S-10	Insurance	Reduce O&M expense by $272,000.
S-11, IN-5	Medical Benefits	Reduce O&M expense by $1.2 million.
S-13	Cost of Capital	Capital structure: 50% equity / 50% debt. Cost of Long-Term Debt: ceiling of 5.203% plus fees. Return on Equity (ROE) of 9.5%.
S-14	Post Retirement Costs / Pension	Reduce O&M expense by $1.55 million. Withdraw accounting treatment language request, and capitalize pension and post-retirement plans in a manner consistent with PGE's method prior to the issuance of FASB ASU 2017-07.
S-15	AFUDC	Hold workshop to review AFUDC formula and calculations prior to final update.
S-16	Fee Free Bank Card	Reduce O&M expense by $503,000.
S-17, S-31	Load Forecasting	Use 15-year average weather assumption. Reduce outboard energy efficiency load decrement by 25%.
S-18, S-30	Other Revenue and Low Services	Increase Other Revenue and reduce O&M expense by a combined total of $1.5 million.
S-19	Carty AFUDC	Reduce plant-in-service by $7.7 million and decrease ADIT by $1.0 million to comply with IRS normalization requirements.
S-20	Major Maintenance Accruals	Calculate Colstrip using three-year average, which increases production expense by $244,000. File for deferred accounting annually.

S-21	Generation O&M	Reduce O&M expense by $90,000.
S-22	Affiliated Interests	PGE will hold workshop prior to next general rate case.
S-23	Customer Services	Reduce O&M expense by $300,000.
S-24	Environmental Licensing	No adjustment.
S-25	R&D / Memberships	Reduce O&M expense by $911,680.
S-26, IN-4	Depreciation	Reduce depreciation expense by $7.3 million associated with asset retirement obligation. Reduce depreciation expense by $8.2 million to reflect Docket No. UM 1809. Decrease accumulated depreciation by $8.2 million and increase ADIT by $1.1 million to comply with IRS normalization requirements.
S-27, IN-7, S-12	Plant in Service / Production Tax Credit Carryforwards / Distribution O&M	Reduce rate base by $50 million.
S-29	Legal Fees	No adjustment.

Q. Please summarize the rate spread and rate design portion of the Stipulation.

A. The Parties have agreed to the following:

1. Set the Schedule 7 Basic Charge at $11.00 per month.
2. Restructure the Schedule 7 Portfolio Time of Use (TOU) distribution and transmission (D&T) prices such that these prices would be set to zero during off-peak periods with commensurate increases during on- and mid-peak periods.
3. Reduce the Schedule 110 Energy Efficiency Customer Service prices effective January 1, 2018.
4. Update the outdoor lighting schedule prices for the final cost of capital in this proceeding.
5. PGE will begin amortization of the Schedule 5 Direct Load Control Pilot and Schedule 6 Residential Pricing Pilot deferred expenses commencing January 1, 2018.
6. PGE, in its next general rate proceeding will either propose or state why they are not proposing demand charges for Schedule 32, Small Nonresidential General Service.
7. Commence on an annual basis, the reporting of customers' average use per customer by month, and the average and range of the load factors of customers served under the

provisions of Schedule 38, Large Nonresidential Optional Time-of-Day Standard Service.

8. Eliminate the Customer Impact Offset (CIO) for all rate schedules with the exception of the lighting schedules.
9. Adopt ICNU's proposal regarding allocation of the Schedule 90 load following credit.
10. Accept the PGE proposal of functionalizing and allocating Automated Meter Infrastructure (AMI) costs and the cost of the Customer Information (CIS) and Meter Data Management System (MDMS) costs. In addition, the Parties request that the Commission open an investigatory docket to examine the functionalization and/or allocation of PGE's "smart grid" costs.
11. Functionalize approximately $300,000 in energy storage costs to generation from the customer category.
12. For Schedule 85, set the difference between secondary voltage and primary voltage Facility Capacity Charges at $0.25 kW per month. In addition, the Parties agree that in its next general rate case PGE will examine the test period maintenance cost contained in FERC accounts 583, 584, 593, and 594 and estimate the amounts attributable to secondary voltage service conductors, secondary voltage conductors, and primary voltage conductors.

Q. Does this 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.

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

A. Yes. As previously stated, this Stipulation resolves all remaining issues in this proceeding, except for Energy Efficiency issues raised by CUB, which does not relate to PGE's revenue requirement.

II. Resolved Revenue Requirement Issues

Q. Please describe the Stipulation regarding Uncollectibles (S-1).

A. PGE's initial filing included a 0.370% uncollectibles rate based on a five-year average. In Staff/400, Staff proposed applying a three-year average methodology to determine the test year uncollectibles rate. Staff believed the three-year average reflected a downward trend in the uncollectible rate not fully captured with the five-year average.

Q. How do the Parties resolve this issue?

A. The Parties agree that for settlement purposes a 0.3431% uncollectibles rate will be used for the test year, reflecting the 2014-2016 historical average of actual write-offs.

Q. Please describe the Stipulation regarding OPUC Fees (S-2).

A. PGE's initial filing included an OPUC fee rate of 0.375%. In PGE's response to OPUC Data Request No. 644, PGE updated this rate to reflect the most recent three years of actual wholesale and retail revenues, producing an OPUC Fee Rate of 0.3211%. In Staff/400, Staff expressed concerns over whether PGE was correctly accounting for the OPUC fees associated with wholesale revenues.

Q. How do the Parties resolve this issue?

A. The Parties agree that for settlement purposes a revised rate of 0.3211% will be used for 2018. The stipulated rate reflects PGE's adjustment to the gross-up factor for sales for resale based on the three-year average of historical actual sales for resale to retail revenue. PGE will also reduce the OPUC Fee amount to reflect a 0.3000% rate on the incremental revenue requirement of this case. This means that 3.000% will be used as the OPUC fee revenue sensitive percentage in the net to gross factor for the incremental revenue requirement.

Q. Please describe the Stipulation regarding Interest Synchronization (S-3).

A. The Parties agree that for settlement purposes PGE's and Staff's revenue requirement calculations are in alignment. There is no change to revenue requirement.

Q. Please describe the Stipulation regarding IT Cybersecurity Amortization (S-4).

A. The Parties agree that for settlement purposes PGE will conduct a workshop, prior to the second quarter of 2018, in order to provide Staff with additional information regarding the segregation and identification of development costs. There is no change to revenue requirement.

Q. Please describe the Stipulation regarding Accumulated Deferred Income Taxes (ADIT) (S-5, IN 8-13).

A. In ICNU/300, ICNU contested PGE's inclusion of a number of ADIT items in rate base. The Parties agree that for settlement purposes, PGE's rate base will be reduced by approximately $27.8 million. This resolves each of ICNU's ADIT adjustments with the exception of production tax credit carryforwards, which is discussed separately below.

Q. Please describe the Stipulation regarding Working Cash (S-6).

A. The Stipulating Parties agree that for settlement purposes PGE will continue to use a 3.628% working cash factor, as filed in PGE's direct testimony. The 3.628% was used in PGE's last general rate case, Docket No. UE 294. PGE testified that it updated its lead lag study in the third quarter and this update produced a working cash factor of 3.789%. PGE decided to not use the updated rate in this case because it is not significantly different from the old rate. PGE intends to perform a new lead lag study prior to its next rate case.

Q. Please describe the Stipulation regarding Major Storms (S-7).

A. PGE's initial filing included an update to the 10-year rolling average for Level III storm costs, which increase the annual collection amount to $2.6 million. Additionally, PGE proposed a balancing account mechanism for major storms similar to that for major maintenance accruals as used for thermal generating plants. In Staff/400, Staff testified that utilities generally bear the risk of weather impacts and that if costs from a particular storm are significant, PGE has the ability to file for deferred accounting treatment and did not recommend the use of balancing account treatment. The Parties agree that for settlement purposes PGE will increase the annual collection for Level III storm costs to $2.6 million, which is the amount obtained applying a ten-year average, but with no balancing account mechanism.

Q. Please describe the Stipulation regarding Escalation (S-8).

A. The Parties agree that for settlement purposes there will be no adjustment made to PGE's initial filing for non-labor cost escalation.

Q. Please describe the Stipulation regarding Miscellaneous Labor and Outside Services costs (S-9).

A. Parties settled this issue in two phases. First, the Stipulating Parties agreed to a reduction to PGE's test year operations and maintenance (O&M) and administrative and general (A&G) expenses of $2.394 million, payroll taxes of $0.031 million, and rate base of $1.052 million. This adjustment has several components, which we summarize as follows:

- S-9.1 Wages & Salaries: $0.371 million expense reduction; $0.187 million rate base reduction
- S-9.3 Incentives: $1.99 million expense reduction; $0.865 million rate base reduction
- S-9.5 Payroll Taxes: $0.031 million expense reduction
- S-9.6 Depreciation Expense: $0.034 million expense reduction

For S-9.1 Staff based its analysis on wages and salaries using 2015 actuals and escalation using a consumer price index (CPI). For S-9.3 Staff proposed removing officer incentives from PGE's test year forecast and decreasing non-officers' incentives by the differential between PGE's test year forecast for non-officer incentives and an amount equal to 50 percent of 2015 non-Officer incentives escalated using CPI. After reviewing its forecasted costs, PGE agreed with parts of Staff's proposal, subject to certain corrections and/or revisions to Staff's calculation on certain items. The Parties agreed to the removal of officer incentives and an adjusted forecast of non-officer incentives and wages and salaries. These reductions, coupled with the impact to payroll taxes and depreciation O&M are reflected in the totals above.

Second, through further negotiations, the Parties agreed to an additional non-specified revenue requirement reduction of $6.0 million to settle all issues related to full time equivalent employees (FTEs), which include how much should be included in revenue requirement for incremental FTE additions. PGE's initial filing included revenue requirement for approximately 270 new incremental FTEs. Staff, ICNU, and CUB all filed testimony questioning the appropriateness of rate recovery for this many incremental FTEs. Staff's opening testimony position was a revenue requirement decrease of $24.241 million of which approximately half was for the incremental FTEs. The Parties agree that including $6 million for incremental FTEs strikes a reasonable balance between the need for the new employees described in PGE's testimony and customers' interests in keeping rates as low as reasonably possible.

The Parties also agreed to a $0.1 million expense reduction to PGE's forecasted expense forA&G Contractor costs. With this additional agreement, all S-9 issues are resolved.

Q. Please describe the Stipulation regarding Customer Engagement Transformation (CET) development O&M costs (S-28).

A. For years 2014 through 2016, PGE booked CET development costs to a regulatory asset that was amortized in base rates in each rate case during that period. Program development costs for 2017 were deferred separately and have not yet been amortized. PGE's initial filing included a request to book 2018 CET development O&M to a regulatory asset and amortize the remaining balance of all the 2014-2018 deferrals in base prices over a ten year period beginning in 2018. The Parties agreed to move the unamortized balance of CET deferred costs for 2014-2016 (as of year-end 2017) and PGE's forecasted CET O&M costs for 2017 and 2018 from base rates into a supplemental schedule. The supplemental schedule will amortize the 2014-2016 deferral balance and the 2017 and 2018 forecasted costs over five years beginning January 1, 2018.

Q. Please describe the Stipulation regarding Insurance (S-10).

A. In Staff/400, Staff argued that prior Commission decisions determined that cost of all premiums for Director and Officer (D&O) liability insurance should be split between customers and shareholders. In its initial filing, PGE split the cost of certain layers of D&O insurance between ratepayers and shareholders by including only 50 percent of the cost in revenue requirement, but allocated all of the cost of the primary layer of insurance to ratepayers by including the full cost of this layer in revenue requirement. The Parties agree for settlement purposes to reduce D&O expense by $0.272 million, which is 50% of the primary layer of D&O insurance. The result is that ratepayers and shareholders will share the entire cost of D&O insurance 50/50.

Q. Please describe the Stipulation regarding Medical Benefits (S-11 and IN-5).

A. In ICNU/300, ICNU proposed to limit the escalation of medical benefits to increases that are known and measurable and also noted where PGE had incorrectly escalated the cost of medical benefits for 2018. in PGE's response to ICNU Data Request No. 036, PGE provided support for the 2018 premium escalations, while correcting an inflation escalation amount.

Q. How do the Parties resolve this issue?

A. The Parties agree for settlement purposes to reduce medical expense by $1.2 million.

Q. Please describe the Stipulation regarding Cost of Capital (S-13 and IN-1).

A. In its initial filing, PGE proposed a capital structure consisting of 50% equity and 50% long-term debt, and a cost of long-term debt at 5.170%. The Company's expert witness, Dr. Bente Villadsen, provided support for a requested return on equity of 9.75%. Staff and ICNU filed responsive testimony contesting PGE's cost of capital. Staff's testimony supported a capital structure consisting of 50.5% long-term debt and 49.5% equity. Staff proposed a cost of long-term debt of 4.852% and a return on equity of 9.2% based on detailed market analyses. ICNU proposed a capital structure consisting of 51.35% long-term debt and 48.65% equity. ICNU accepted the Company's proposed cost of long-term debt, but proposed a return on equity of 9.25%, also based on detailed market analyses.

To resolve these disputed issues, the Parties agree to a capital structure of 50% equity and 50% long-term debt, a cost of long-term debt of 5.203%, and a return on equity of 9.5%. The cost of long-term debt of 5.203%, subject to a minimal adjustment for issuance fees, is set as a ceiling within this proceeding. Any changes to debt issuances that reduce PGE's overall cost of long-term debt below 5.203% will be reflected in PGE's final revenue requirement update. Additionally, any subsequent changes through June 30, 2018 that reduce PGE's overall cost of long-term debt below 5.203% will be reflected through a supplemental tariff filing.

Q. Please describe the Stipulation regarding Post Retirement costs (S-14).

A. PGE's initial filing included a pension forecast reflecting changes expected to be required by the proposed Financial Accounting Standards Board (FASB) Accounting Standards Update (ASU) titled, *Compensation – Retirement Benefits [Topic 715]: Improving the Presentation* *of Net Periodic Pension Cost and Net Periodic Postretirement Benefit Cost.* Alternatively, PGE proposed accounting treatment language that would allow PGE to continue to record pension expense in a manner consistent with historical treatment. In Staff/500, Staff stated that the proposed accounting treatment language was not necessary.

Q. How do the Parties resolve this issue?

A. The Parties agree that for settlement purposes PGE will withdraw its accounting treatment language request, and will capitalize pension and post-retirement plans in a manner consistent with PGE's method prior to the issuance of FASB ASU 2017-07. This results in a reduction to expense of $1.55 million.

Q. Please describe the Stipulation regarding Allowance for Funds Used During Construction (AFUDC) (S-15).

A. The Parties agree that for settlement purposes PGE will hold a workshop with Staff and other parties prior to the final revenue requirement update in this proceeding, to review the FERC-specified AFUDC formula and PGE's calculations/transactions. This workshop is currently scheduled for late September.

Q. Please describe the Stipulation regarding PGE's Fee Free Bank Card program (S-16).

A. In Staff/600, Staff concluded that both PGE and Staff have been overly optimistic in their expectations for the customer adoption of fee free bankcard payments and that PGE was collecting more in rates for fee free bankcard transactions than are actually occurring. Staff indicated that while the customer adoption rate is increasing, it is not doing so as rapidly as expected. Staff also testified that it believed the amount included in PGE's revenue requirement was based on an overestimation of the cost per transaction.

Q. How do the Parties resolve this issue?

A. The Parties agree that for settlement purposes, PGE will set the per-transaction rate at $1.54 and the adoption rate to 10.84%, both of which are lower than what underlies the revenue requirement in their initial filing. These changes result in a reduction to expense of $0.503 million.

Q. Please describe the Stipulation regarding Load Forecasting (S-17 and S-31).

A. Staff identified concerns with using PGE's proposed Hinge Fit model for forecasting 2018 load and ultimately proposed that PGE use a 15-year average of weather similar to that used in prior general rate cases. Additionally, Staff proposed an alternative forecast model for PGE's non-residential load forecast. For settlement purposes, Parties agreed to use PGE's load forecast model with the following adjustments for this case only:

1. Use of a 15-year average weather assumption; and
2. A 25% reduction to PGE's outboard energy efficiency (EE) decrement to its 2018 load forecast.

Additionally, Parties agreed that PGE will not make any additional variable or structural changes to the load forecast model within this case. PGE will also conduct a workshop before year-end 2017 on load forecasting and will provide Staff an evaluation of non-stationarity in its load forecast models, including any necessary corrections, before the second quarter of 2018.

Q. Does the load forecast settlement impact the Lost Revenue Recovery Adjustment (LRRA) portion of Schedule 123 Decoupling?

A. No. For purposes of computing the 2018 LRRA, PGE will compare the total projected amount of EE attributed to Schedule 109 funding contained in the test period to the attributed amount of EE as reported by the Energy Trust of Oregon (ETO).

Q. Please describe the Stipulation regarding Other Revenue and Low Services (S-18 and S-30).

A. For Other Revenue, both Staff and CUB proposed adjustments based on PGE's historical actuals. ICNU also filed testimony expressing concern with the reduction to Other Revenues for the test period, but did not propose a discrete adjustment. For the Low Clearance Correction Program, Staff proposed an adjustment based on a sharing of costs between PGE and customers. Staff and PGE do not agree on the break-down of the adjustment between expense and other revenue, however Staff and PGE do agree on the revenue requirement effect. The Parties agree that for settlement purposes PGE will increase its Other Revenue forecast and reduce its O&M expense by a combined total of $1.5 million to settle both issues.

Additionally, the Parties agree to the following conditions specific to the Low Clearance Correction Program:

1. A ten-year inspection cycle and two-year correction cycle for service connections with point of attachment (POA) below eight feet and between eight and ten feet;
2. Beginning January 1, 2018 and until the next general rate case, PGE will collect $1,583,742/year in prices for the Low Clearance program plus the loaded labor expenses associated with the Low Clearance program FTEs (i.e., two fully loaded FTEs);
3. PGE agrees to modify the portions of testimony agreed to with Staff related to low service connects;
4. Staff agrees to withdraw its recent data requests (DRs) dealing with Low Service Connects (i.e., OPUC DR Nos. 698-708);
5. PGE will file an annual report with the OPUC containing the following information:

a. The annual cost of the Low Clearance program;

b. The amount of Low Clearance program costs capitalized, if any;

c. The number of service connections inspected for POA height;

d. The number of inspected service connections found to have POA/POW (point of weatherhead) below eight feet;

e. The number of inspected service connections found to have POW between eight and ten feet;

f. The number of sub-eight-foot connections corrected and the cost of correction; and

g. The number of eight to ten-foot connections corrected and the cost of correction.

Additionally, PGE will make best efforts to correct low service connections below eight feet and above eight feet in approximately the same ratio as discovered in inspections.

Q. Please describe the Stipulation regarding Carty AFUDC (S-19).

A. In Staff/700, Staff testified that until the prudence of investments beyond amounts stipulated to in Docket No. UE 294 is determined, it is not appropriate to increase the rate base for Carty beyond the original stipulation. The timing of a prudence determination related to additional Carty investments will depend on the outcome of litigation arising from the Performance Bond between PGE and sureties. Because of this, PGE agreed that it was appropriate to remove the incremental AFUDC at this time. As such, the Parties agree that for settlement purposes PGE will remove the AFUDC calculated for the Carty Generation Station from mid-May through July 29, 2016. However, nothing precludes PGE from requesting these amounts in a future proceeding. This results in a reduction to rate base of

$7.7 million. In addition, PGE will decrease the associated ADIT by approximately $1.0 million to comply with IRS normalization requirements.

Q. Please describe the Stipulation regarding Major Maintenance Accruals (MMAs) (S-20).

A. PGE's initial filing requested the inclusion of an MMA for Colstrip Units 3 and 4, consistent with PGE's other current MMAs. While Staff did not take issue with the inclusion of an MMA for Colstrip, they stated a three-year moving average (as opposed to PGE's requested five-year average) would better match the major outage schedule at the plant.

Q. How do the Parties resolve this issue?

A. The Parties agree that for settlement purposes PGE will calculate and include a Colstrip MMA using a three-year moving average, which results in a $244,000 increase to PGE's production O&M costs. Additionally, PGE will file deferred accounting applications associated with MMAs every year beginning on January 1, 2018.

Q. Please describe the Stipulation regarding Generation O&M (S-21).

A. In Staff/700, Staff recommended reducing consulting expense by $90,000. This reduction is attributed to anticipated cost reductions resulting from the addition of one Power Supply Engineering Services Services Analyst.[1] The Parties agree that for settlement purposes PGE will reduce generation expense by $90,000.

Q. Please describe the Stipulation regarding Affiliated Interests (S-22).

A. While PGE's initial filing did not specifically address affiliated interests, Staff conducted a review of PGE's process for assigning and allocating the costs of affiliates. Through this review, Staff identified certain concerns with PGE's process. The Parties agree that for

[1] Staff/700, Kaufman/29

settlement purposes PGE will hold a workshop prior to the next general rate case to address Staff's concerns regarding allocation factors.

Q. Please describe the Stipulation regarding Customer Service expenses (S-23).

A. PGE's initial filing included non-labor Customer Services expense, excluding uncollectibles and CET expenses, of approximately $16.7 million. Staff proposed a reduction to this expense based on a three-year average of dollars spent per customer. After reviewing its forecasted costs, PGE acknowledged that certain outside services expenses could be postponed. The Parties agree that for settlement purposes PGE will reduce non-labor Customer Service expense by $300,000.

Q. Please describe the Stipulation regarding Environmental and Licensing Services (S-24).

A. Staff identified concerns regarding the change in environmental and licensing services (ELS) costs from PGE's 2016 forecast compared with the 2018 forecast provided in this proceeding. Staff's primary concern was that when removing the costs associated with PGE's Portland Harbor Environmental Remediation Account (PHERA), PGE's forecasted 2018 ELS costs appeared higher than 2016 costs. Subsequent to settlement discussions, PGE provided Staff with work papers demonstrating that the costs requested in this case are lower than 2016 costs exclusive of PHERA related costs. Based on the information provided, the Parties agree that for settlement purposes, there will be no adjustment related to PGE's 2018 ELS forecast.

Q. Please describe the Stipulation regarding Research and Development and Memberships (S-25).

A. PGE's initial filing included a Research and Development (R&D) forecast of approximately $3.0 million and a forecast of Membership costs of approximately $3.6 million. Staff proposed a reduction to PGE's R&D forecast based on the assumption that PGE could eliminate or postpone certain projects. Staff proposed a reduction to PGE's Memberships forecast based on a lack of explanation provided for certain costs. The Parties agree that for settlement purposes, PGE will reduce its R&D expense by $800,000 and Memberships expense by $111,680. To address concerns regarding R&D projects, PGE will file a report in October of each year regarding prospective R&D projects and will also continue to file the annual retrospective report as stipulated in UE 294. PGE will continue the historic treatment of administrative costs.

Q. Please describe Staff's and ICNU's concerns regarding PGE's filed depreciation amounts.

A. In Staff/1000, Staff recommended that PGE's depreciation expense reconcile to the rates adopted in Docket No. UM 1809 (PGE's 2015 Depreciation Study). ICNU expressed concerns related to an increase in PGE's asset retirement obligation (ARO) compared to UM 1809. After reviewing the final results of UM 1809 and comparing the results to PGE's initial filing, PGE determined that adjusting its ARO and depreciation expense to match the outcome of UM 1809 was appropriate.

Q. Please describe the Stipulation regarding Depreciation (S-26 and IN-4).

A. The Stipulating Parties agree that for settlement purposes, PGE will reconcile in an electronic spreadsheet the following items:

- The final depreciation expense amount in PGE's revenue requirement (including the Carty component and exclusive of the plant adjustments agreed to in this stipulation); and
- The depreciation amount as determined by the UM 1809 depreciation study and based on: 1) plant in service at year-end 2017; and 2) the adjusted annualization of

2017 depreciation expense to reflect the declining balance impact during 2018. The reconciliation will include the same level of detail as the summary calculations in UM 1809.

Additionally, PGE will remove approximately $7.3 million from depreciation expense associated with the asset retirement obligation and PGE will reduce depreciation expense by approximately $8.2 million to reflect the settlement reached in the depreciation study. To maintain compliance with IRS normalization rules (see PGE Exhibit 200, Section III), PGE will update accumulated depreciation and accumulated deferred taxes to coincide with the revised depreciation expense. This amounts to a reduction in accumulated depreciation of approximately $8.2 million and an increase in ADIT of approximately $1.1 million.

Q. Please describe the Stipulation regarding Plant in Service (S-27), Production Tax Credit (PTC) Carryforwards (IN-7), and Distribution O&M (S-12).

A. PGE's filed case proposed to add approximately $465 million in capital additions to rate base. Both Staff and ICNU questioned the level of these additions, primarily based on the amount of plant that was scheduled to go into service in December of the test year. Staff proposed to remove $64.3 million from plant in service, while ICNU recommended an $84.3 million rate base reduction related to plant in service. As noted above, ICNU also proposed to remove a number of ADIT items from rate base, including production tax credit carryforwards.

The Parties agree that for settlement purposes PGE will make a non-specified reduction to rate base of $50 million to resolve these three issues. Parties agree that they are free to raise issues related to PGE's PTC carryforwards in future proceedings. Additionally, specific to Plant in Service, Parties agree to the following:

- PGE will file attestations for the following six projects:

1. P35959 WSH Structural/Reliability Upgrades,
2. P35802 Horizon Phase II Project,
3. P36042 Tektronix Substation Upgrade,
4. P35938/P36354 Field Voice Communications/Spectrum 200 MHz,
5. P36109/P36005 Distribution Automation/Spectrum 700 MHz, and
6. P36146 Energy Market Readiness Project;

- If the above-mentioned projects do not come into service prior to rate-effective date, PGE will remove the amounts not in-service from base rates effective January 1, 2018. If, due to timing of the projects, PGE is unable to remove these amounts from rates prior to January 1, 2018, PGE agrees to refund to customers the amounts recovered;
- PGE agrees to answer information requests from all parties related to plant-in-service included in rates through this general rate case; and
- PGE agrees to file a report by March 15, 2018 showing: (1) the list of capital projects planned for 2017 as represented in PGE's Second Supplemental Response to DR No. 139, dated August 2, 2017; (2) a list of capital projects transferred to plant in 2017; (3) the forecast amount for each capital project; (4) the actual amount for each capital project; and (5) the variance amount between forecast and actual expenditures.

Finally, while PGE's projected amount for Plant in Service is resolved for this case, this settlement does not address Staff's concern that capital projects are closed to plant that may not have been reviewed by the Commission at the time rates become effective.

Q. Please describe the Stipulation regarding Legal Fees (S-29).

A. Staff's Opening Testimony expressed concerns with PGE potentially including forecasted legal costs related to the Schedule 134, Gresham Privilege Tax Payment Adjustment. As these concerns were resolved through Data Requests between PGE and OPUC Staff, Staff withdrew this issue.

III. Rate Spread and Rate Design Issues

Q. What Schedule 7 Basic Charge did PGE initially propose and how do the Stipulating Parties resolve this issue?

A. PGE initially proposed a Schedule 7 monthly Basic Charge of $11.50, an increase of $1.00 from the current $10.50. In Staff/1300, Staff proposes that the percentage increase in the Schedule 7 Basic Charge should not exceed the base rate percentage increase to Schedule 7, which results in an approximate $11.00 per month Basic Charge. While not necessarily agreeing to a methodology or rationale, in the interest of settlement, the Parties agree to the Staff recommendation of setting the Schedule 7 Basic Charge at $11.00 per month.

Q. Why does Staff propose to change the Schedule 7 TOU D&T structure?

A. In Staff/1400, Staff specifies that their proposal better reflects costs, is more likely to induce greater participation in the residential TOU option, and may provide a societal air quality benefit should the pricing structure induce more PGE customers to substitute electric vehicles for internal combustion vehicles.

Q. How do the Parties resolve this issue?

A. The Stipulating Parties agree with Staff's motivations and logic, and adopt the Staff proposal.

Q. Why do the Parties propose to reduce Schedule 110 prices?

A. The Parties propose this because PGE has accumulated a balance of approximately $465,000 as of February 2017 in the Schedule 110 Balancing Account. In Staff/1500, Staff provides several methods by which PGE could effectively amortize this balance, including transferring the excess funds to the ETO. However, in settlement the Parties agree that the best method to amortize the excess Schedule 110 funds is to reduce the Schedule 110 prices so that the customers to whom Schedule 110 is applicable would receive the benefit directly.

This reduction in prices, effective January 1, 2018 will be accomplished through a PGE Advice Filing.

Q. What do the Parties conclude with respect to updating the UE 319 cost of capital as applied to the outdoor lighting schedules' prices?

A. The Stipulating Parties conclude that it is appropriate to update the cost of capital when determining the prices for these rate schedules. PGE notes that it has routinely performed this update for numerous past proceedings.

Q. What is Staff's concern regarding the amortization of the deferred Schedule 5 and Schedule 6 expenses and how do the Parties resolve this concern?

A. In Staff/1300, Staff expresses concern about the potential amount of accumulated interest accruing to the balancing account should PGE not amortize the deferred amounts in a timely manner. To alleviate Staff's concern, the Parties agree to have PGE commence amortization of the balancing account related to Schedules 5 and 6 effective January 1, 2018. PGE proposes to amortize these deferred expenses in an Advice Filing through either Schedule 105, Regulatory Adjustments or through Schedule 135, Demand Response Cost Recovery Mechanism.

Q. Please explain the nature of the settlement regarding Schedule 32 demand charges.

A. Staff expresses a general desire for recovering allocated transmission and distribution costs through demand charges rather than through volumetric prices with respect to the nonresidential rate schedules other than the irrigation and pumping rate schedules. Staff cites Pacific Power Schedule 23 (0-30 kW) as an example of an Oregon utility that includes demand charges for customers at or below 30 kW. Staff also acknowledges that until PGE's CET program is complete, a structure with demand charges for Schedule 32 is not a viable option for 2018.

Q. How do the Parties resolve this issue?

A. The Parties agree that in PGE's next general rate proceeding, PGE will either propose demand charges for Schedule 32, presumably at some introductory level, or state in testimony why PGE does not believe that demand charges for Schedule 32 are appropriate. In this manner, this important topic will receive a more complete vetting, and also allow for a more complete customer education process, if applicable.

Q. What are Staff's concerns regarding Schedule 38?

A. Similar to their concerns regarding Schedule 32, Staff expresses a desire for PGE to either implement demand charges, or some form of demand response applicable to Schedule 38 customers. The demand charges would replace the volumetric nature of distribution and transmission cost recovery for these customers, all of whom have relatively low load factors in comparison to the large nonresidential customers on rate schedules with demand charges.

Q. How do the Parties resolve this issue?

A. In the interest of settlement, the Parties agree to an annual reporting requirement for Schedule 38. This annual report will include the average monthly consumption and the average and range of load factors for Schedule 38 customers. In this manner, interested parties may monitor the degree to which Schedule 38 consumption patterns may change over time, and, if applicable, suggest appropriate future actions.

Q. What concerns do both Staff and ICNU express with respect to PGE's CIO proposal?

A. Both Staff and ICNU are concerned that PGE's proposal to mitigate the Schedule 7 price increase is unwarranted given that the base rate percentage difference between Schedule 7 and the overall base price impact is less than two percent. Staff and ICNU are further concerned about PGE proposing that direct access customers should help mitigate the Schedule 7 price increase.

Q. How do the Parties resolve this issue?

A. The Parties agree to eliminate the CIO with the exception of equalizing the distribution prices for the outdoor lighting schedules. The Parties further agree that it is appropriate to revisit the CIO should "rate shock" result from resolution of the issue sponsored by CUB.

Q. What did PGE originally propose regarding the allocation of load following costs and what issues were identified by others?

A. PGE proposed an analysis that evaluated the within-hour load ramping requirements for the rate schedules and attributed load following costs to the rate schedules based on these within-hour ramping requirements. ICNU criticized this analysis as being too narrowly focused and proposed adoption of the UE 294 load following methodology that credits Schedule 90 for the absence of load following requirements on the majority of their large load, and charges the other rate schedules for this crediting of Schedule 90. The ICNU proposal results in Schedule 89 receiving the largest surcharge. ICNU also pointed out that their methodology helps to lessen the Schedule 7 rate impact relative to PGE's proposal.

Q. How do the Parties resolve this issue?

A. In the interest of settlement, the Parties agree to the ICNU proposal, but adopt a limit on the surcharge applicable to Schedule 89 of 0.57 mills/kWh. If the surcharge would otherwise exceed this amount, the credit applicable to Schedule 90 will decrease accordingly. In this manner, the impact on Schedule 89 customers will be mitigated should the amount of Schedule 89 load decrease due to either load forecast changes or enrollment in long-term direct access under the provisions of Schedule 489.

Q. Please describe the issues raised and the settlement the Parties reached regarding the AMI meter and CIS/MDMS issues.

A. In its opening testimony, CUB specified that PGE should functionalize and/or allocate the costs of AMI meters and the costs of the CIS and MDMS in a manner that reflects the benefits CUB believes these "smart grid" investments provide. This differs, for example, from PGE's allocation of AMI meters as a customer-related cost that is functionalized to distribution. In the interest of settlement, the Parties agree to accept the PGE allocation of these costs, and request that the Commission open an investigatory docket to examine the functionalization and/or allocation of "smart grid" costs. Parties request that the investigation address the appropriate functionalization and/or allocation of such costs.

Q. Please describe the settlement of the approximate $300,000 in storage costs?

A. In its Direct Testimony, PGE functionalized approximately $300,000 in storage-related O&M costs to Other Consumer Service. CUB, in its Opening Testimony proposed an allocation that included both capacity and energy. The Parties agree that the storage-related O&M costs are more appropriately functionalized to generation. This re-functionalization will provide for an allocation of the storage costs in a manner similar to CUB's proposal.

Q. What is the basis for setting the Schedule 85 Facility Capacity Charge difference between secondary voltage and primary voltage customers at $0.25 kW-month?

A. In its Opening Testimony, Fred Meyer states that PGE has not adequately examined the degree to which distribution capital costs and maintenance costs are attributed to secondary and primary voltage customers, and hence there should be a larger price differential between the two Schedule 85 delivery voltage options. Fred Meyer acknowledged that it would be difficult for PGE to perform such a study in a relatively short time period and suggested a Facility Capacity Charge price differential of $0.25 kW-month.

PGE does not necessarily agree with Fred Meyer's assessment of a $0.25 price differential, but PGE does acknowledge the existence of capital and maintenance cost amounts for secondary voltage service conductors within the FERC accounts specified above. This is evidenced by PGE's response to Fred Meyer Data Request No. 008.

Q. How do the Parties resolve this issue?

A. The Parties agree to Fred Meyer's proposed $0.25 kW-month Facility Capacity Charge price differential for the Schedule 85 delivery voltages. In addition, the Parties agree that in its next general rate case, PGE will examine the test period marginal capital costs of primary and secondary Distribution Facilities in its current design standards and the maintenance cost contained in FERC accounts 583, 584, 593, and 594 and estimate the marginal capital costs and maintenance amounts attributable to secondary voltage service conductors, secondary voltage conductors, and primary voltage conductors. PGE will also examine the extent to which these costs are applicable to the individual rate schedules.

Q. What did PGE initially propose for the monthly Schedule 32 Basic Charges and how do the Parties resolve this issue?

A. In its Direct Testimony, PGE proposed Schedule 32 Basic Charges of $18.00 and $24.00 for single- and three-phase service respectively. This proposal represented an increase of two dollars per month for each type of service. The SBUA, in settlement, proposed a Schedule 32 Basic Charge increase of one dollar per month rather than the two dollars proposed by PGE. In the interest of settlement, the Parties agree to the one dollar per month increase in the Schedule 32 Basic Charge.

Q. What is your recommendation to the Commission regarding these adjustments?

A. The Parties recommend and request that the Commission approve these adjustments. Based on careful review of PGE's filing, consideration of PGE's responses to over 800 DRs, and thorough analysis of the issues during five separate days of settlement conferences, we believe these adjustments represent appropriate and reasonable resolutions of the respective issues in this docket. Rates reflecting these adjustments will be fair, just, and reasonable.

IV. Qualifications

Q. Dr. Brown, please state your education background and experience.

A. I received Bachelor of Science degrees in Agricultural and Resource Economics, and Animal Science from Oregon State University. I received a Master of Science Degree from the University of Wyoming in Economics. I received a Doctorate of Philosophy Degree from Purdue University in Ag. Economics. I have held various economist positions related to the energy industry, including that of Senior Economist at the Public Utility Commission of Oregon. I have worked for PGE since 2007 and have represented PGE in Bonneville Power Administration proceedings, including general rate cases. I have worked as a Manager in Regulatory Affairs at PGE since April 2015.

Q. Does this conclude your testimony?

A. Yes.

List of Exhibits

PGE Exhibit	Description
201	Copy of Partial Stipulation
202	Updated Revenue Requirement

**BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON**

UE 319

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 Oregon Citizens' Utility Board ("CUB"), the Industrial Customers of Northwest Utilities ("ICNU"), Fred Meyer Stores and Quality Food Centers, Division of The Kroger Co. ("Kroger"), Wal-Mart Stores Inc. and Sam's West, Inc. ("Walmart"), and the Small Business Utility Advocates ("SBUA") (collectively, the "Stipulating Parties").

PGE filed this general rate case on February 28, 2017. The filing included fourteen separate pieces of testimony and exhibits. PGE also provided to Staff and other parties voluminous work papers in support of its filing. Since that time, Staff and intervening parties have analyzed PGE's filing and work papers, and submitted more than 800 data requests obtaining additional information. Two schedules were set by the Administrative Law Judge in this matter: one for net variable power cost ("NVPC") issues, and the other for general rate case issues. All NVPC issues have been settled, and a NVPC Stipulation has been filed with the Commission. All parties had the opportunity to file testimony regarding non-power cost issues on June 16, 2017. Settlement conferences were held on July 6, 7, 11, and 24. Some issues were settled prior to PGE filing Reply Testimony on July 18, 2017. An additional settlement conference was held on August 3. The Stipulating Parties participated in these numerous settlement discussions. Calpine Solutions also participated in settlement discussions, and does not object to this Partial Stipulation. No other parties participated in the discussions. As a result of those discussions, the Stipulating Parties have reached a compromise settlement of all remaining issues in this docket except one. The following terms apply to adjustments to be made relative to PGE's filed case.

TERMS OF PARTIAL STIPULATION

1. This Stipulation resolves all remaining issues in this docket except CUB's proposal for the allocation of costs and benefits for energy efficiency funded under Senate Bill 838 (2007).

2. Uncollectibles (S-1). PGE will reduce its uncollectible rate to 0.3431% based on a three-year average of actual write-offs for calendar years 2014-2016.

3. OPUC Fees (S-2). PGE will apply a 0.3211% OPUC Fee rate based on a reduced gross-up factor to account for sales for resale. PGE will also reduce the OPUC Fee amount to reflect a 0.3000% rate on the incremental revenue requirement of this case.

4. Interest Synchronization (S-3). PGE and Staff agree that their respective calculations align. There is no change to revenue requirement.

5. IT Cybersecurity Amortization (S-4). PGE will provide Staff with more information on segregating and identifying development costs. There is no change to revenue requirement.

6. ADIT (S-5) (IN 8-13). In settlement of these accumulated deferred income tax (ADIT) related issues PGE will reduce rate base by approximately $27.8 million.

7. Working Cash (S-6). PGE and Staff agree that their respective calculations align, and PGE will continue to use a 3.628% working cash factor.

8. Major Storms (S-7). PGE will increase the annual storm accrual to $2.6 million as stated in PGE Exhibit 800 and withdraws its request in this docket for a balancing account for Level III storm costs.

9. Escalation (S-8). There will be no adjustment for this issue.

10. Wages and Salaries, Incentives, and FTEs (S-9).

   a. O&M expense will be reduced by $2,425,018 and Capital will be reduced by $1,051,773 relative to PGE's filed case in order to settle wages and salaries and incentive costs. These amounts are calculated by removing PGE's request related to Officer incentives and by using Staff's three-year wages and salaries model, with escalation rates averaged between Staff's and PGE's filed escalation rates for non-bargaining FTEs and the contracted escalation rates for union FTEs. The Stipulating Parties further agree not to place CET benefit loadings into the CET deferral.

   b. The Stipulating Parties agree to a non-specified revenue requirement reduction of $6.0 million to settle all FTE issues. Additionally, the Stipulating Parties agree to a $0.1 million expense reduction to settle Administrative and General Contractor costs.

11. CET Deferral and Amortization (S-28). The remainder of CET deferral costs for 2014-2016 (as of year-end 2017) and PGE's forecasted CET O&M costs for 2017 and 2018 will be moved from base rates into a supplemental schedule. The supplemental schedule will amortize the 2014-2016 deferral balance and the 2017 and 2018 forecasted costs over five years beginning January 1, 2018 with interest accruing at the modified blended treasury rate.

12. Insurance (S-10). D&O insurance costs will be reduced by $272,000.

13. Medical Benefits (S-11) (IN-5). PGE will reduce medical benefit costs by approximately $1.2 million to address ICNU's issue regarding cost escalation.

14. Cost of Capital (S-13) (IN-1). For determining rates in this case:

   a. The Cost of Long-Term (LT) Debt will be set at a ceiling of 5.203% plus a minimal adjustment for fees. Any changes to debt in 2017 that reduce PGE's overall cost of LT Debt below 5.203% will be reflected in PGE's final revenue requirement update. Any subsequent changes through June 30, 2018 that reduce PGE's overall cost of LT Debt below 5.203% will be reflected through a supplemental tariff filing.

   b. The Return on Equity will be 9.50%.

   c. The assumed debt to equity ratio will be 50/50.

15. Post Retirement Costs/Pensions (S-14). PGE withdraws its accounting treatment language request, and will capitalize pension and post-retirement plans in a manner consistent with PGE's method prior to the issuance of FASB ASU 2017-07. This results in a cost reduction of approximately $1.55 million.

16. AFUDC (S-15). In September or October 2017, PGE will hold a workshop with Staff and other parties to review the FERC-specified AFUDC formula and PGE's calculations/transactions.

17. Fee Free Bank Card (S-16). PGE will set the per-transaction rate at the $1.54 level determined in Docket No. UE 294. PGE also agrees with Staff's revised adoption rate of 10.84%. These result in a cost reduction of $503,000.

18. Load Forecasting (S-17 and S-31).

   a. The Stipulating Parties agree to the use of PGE's load forecast model with the following adjustments for this case only:

      i. Use of a 15-year average weather assumption; and

   ii. A 25% reduction to PGE's outboard energy efficiency decrement to its 2018 load forecast.

b. No additional variable or structural changes will be made to PGE's model within this case.

c. PGE will conduct a workshop before year-end 2017 on load forecasting. PGE will provide Staff its evaluation of non-stationarity in its models, and any necessary corrections, before the second quarter of 2018.

19. Other Revenue and Low Services (S-18 and S-30). In settlement of both of these issues, the Stipulating Parties agree:

a. PGE will increase its Other Revenue forecast and reduce its O&M expense by a combined total of $1.5 million.

b. There will be a ten-year inspection cycle and two-year correction cycle for service connections with point of attachment (POA) below eight feet and between eight and ten feet.

c. Beginning January 1, 2018 and until the next general rate case, PGE will include $1,583,742/year in rates for the Low Clearance program plus the loaded labor expenses associated with the Low Clearance program FTEs (i.e., two fully loaded FTEs).

d. PGE agrees to provide an annual report containing the following information:

   i. The annual cost of the Low Clearance program;

   ii. The amount of Low Clearance program costs capitalized, if any;

   iii. The number of service connections inspected for POA height;

   iv. The number of inspected service connections found to have POA/POW (point of weatherhead) below eight feet;

v. The number of inspected service connections found to have POW between eight and ten feet;

vi. The number of sub-eight-foot connections corrected and the cost of correction; and

vii. The number of eight to ten-foot connections corrected and the cost of correction.

e. PGE agrees to modify the portions of testimony agreed to with Staff related to low service connects.

f. Staff agrees to withdraw its recent data requests (DRs) dealing with Low Service Connects (i.e., OPUC DRs 698-708).

g. PGE will make best efforts to correct low service connections below eight feet and above eight feet in approximately the same ratio as discovered in inspections.

20. Carty Generating Station (S-19). For the purposes of this rate case, PGE will remove the AFUDC calculated for the Carty Generating Station from mid-May to July 29, 2016. This results in a reduction to rate base of approximately $7.7 million. To maintain compliance with IRS normalization rules (see PGE Exhibit 200, Section III), PGE will also reduce ADIT by approximately $1.0 million to coincide with the revised plant amount.

21. Major Maintenance Accruals (MMA's) (S-20). PGE will file deferred accounting applications associated with MMAs every year beginning on January 1, 2018. The Colstrip MMA will be calculated using a three-year moving average, which results in a $244,000 increase to PGE's production O&M costs.

22. Generation O&M (S-21). Generation O&M expense will be reduced by $90,000.

23. Affiliated Interests (S-22). PGE will hold a workshop prior to its next general rate case to address Staff's concerns regarding allocation factors.

24. Customer Services (S-23). PGE will reduce non-labor customer service costs by $300,000.

25. Environmental Licensing (S-24). No adjustment for this issue. On August 11, PGE provided additional information to Staff to support this position, including work papers demonstrating that the costs requested in this case are lower than 2016 costs exclusive of Portland Harbor related costs.

26. R&D and Memberships (S-25).

a. PGE will reduce its request by $800,000 to $2.2 million, which includes administrative costs. To address concerns regarding R&D projects, PGE will file a report in October of each year regarding prospective R&D projects and will also continue to file the annual retrospective report as stipulated in UE 294. PGE will continue the historic treatment of administrative costs.

b. Membership costs will be reduced by $111,680.

27. Depreciation (S-26) (IN-4).

a. PGE will provide a reconciliation in an electronic spreadsheet of the following items:

i. The final depreciation expense amount in PGE's revenue requirement (including the Carty component and exclusive of the plant adjustments agreed to in this stipulation); and

ii. The depreciation amount as determined by the UM 1809 depreciation study and based on: 1) plant in service at year end 2017; and 2) the adjusted annualization of 2017 depreciation expense to reflect the declining balance impact during 2018. The reconciliation will include the same level of detail as the summary calculations in Docket No. UM 1809.

b. PGE will remove approximately $7.3 million from depreciation expense associated with the asset retirement obligation.

c. PGE will reduce depreciation expense by approximately $8.2 million to reflect the settlement reached in the depreciation study, Docket No. UM 1809. To maintain compliance with IRS normalization rules (see PGE Exhibit 200, Section III), PGE will also reduce accumulated depreciation by approximately $8.2 million and increase ADIT by approximately $1.1 million to coincide with the revised depreciation expense.

28. <u>Plant in Service (S-27), PTC ADIT (IN-7), Distribution O&M (S-12)</u>.

a. The Stipulating Parties agree to a non-specified rate base reduction of $50 million to resolve these three issues.

b. The Stipulating Parties agree they are free to raise issues related to PGE's production tax credit (PTC) carryforwards in future proceedings.

c. Regarding Plant in Service:

i. PGE agrees to file attestations for six large projects scheduled to close to plant in the second half of 2017.

ii. If any of these projects do not come into service prior to January 1, 2018, PGE will remove the amounts not in service from base rates effective January 1, 2018. If, due to timing of the projects, PGE is unable to remove these amounts from rates prior to January 1, 2018, PGE will refund to customers the amounts recovered.

iii. PGE agrees to answer information requests from all parties related to plant-in-service included in rates through this general rate case.

iv. PGE agrees to file a report by February 15, 2018 showing: (1) a list of capital projects that were planned for 2017 as represented in PGE's Second Supplemental Response to DR No. 139, dated August 2, 2017, (2) a list of capital projects transferred to plant in 2017, (3) a forecast amount for each capital project, (4) the actual amount for each capital project, (5) the variance amount between forecast and actual expenditures.

29. Legal Fees (S-29). Staff's concerns were resolved through a data request and this issue is withdrawn.

30. Ratespread and Rate Design. The Stipulating Parties agree as follows:

a. The Schedule 7 Basic Charge will be $11.00 per month.

b. The Schedule 32 Basic Charge will be increased by one dollar per month for single and three-phase service respectively.[1]

c. Schedule 110 prices will be reduced to begin amortizing the excess balance effective January 1, 2018.

d. Lighting schedule prices will be updated to reflect the Cost of Capital adopted by the Commission in this docket.

e. PGE will begin amortization of the Schedules 5 & 6 balancing accounts effective January 1, 2018.

f. In PGE's next general rate case, PGE will either propose Schedule 32 demand charges, or state why it proposes to keep volumetric prices instead.

[1] SBUA's participation has been limited in this docket and SBUA input regarding this Partial Stipulation is limited to this provision. SBUE takes no position on other provisions of this Partial Stipulation.

g. Adopt Staff's Schedule 7 TOU proposal, and keep Schedule 38 in its present form. Additionally, PGE will report annually to Staff and other interested parties on Schedule 38 customers' average use per customer by month and the average range of load factor.

h. Eliminate the Customer Impact Offset (CIO), except for the lighting schedules. Parties agree to keep open the option of revisiting the customer impact offset for purposes of resolution of the EE issue.

i. With respect to the Schedule 90 load following credit, accept ICNU's proposal of crediting Schedule 90 (1.13 mills/kWh + 0.25 mills/kWh for 150 MW), and allocating the costs of this credit to other cost of service rate schedules. However, the Schedule 89 surcharge will not exceed 0.57 mills/kWh. The Schedule 90 additional credit will be reduced accordingly if the Schedule 89 surcharge otherwise exceeds the 0.57 mills/kWh.

j. Accept PGE allocations for advanced metering infrastructure meters, the customer information system, and meter data management system.

k. Re-functionalize storage costs of approximately $300,000 to generation from customer.

l. The Stipulating Parties request that the Commission open an investigative docket to address the appropriate functionalization and/or allocation of PGE smart grid costs.

m. Set the Schedule 85 secondary/primary Facility Capacity Charge price differential of $0.25/kW-month. In addition, in its next GRC, PGE will examine the test period marginal capital costs of primary and secondary Distribution Facilities in its current design standards and the maintenance costs contained in FERC accounts 583, 584, 593, and 594 and estimate the amounts attributable to secondary voltage service conductors, secondary voltage conductors, and primary voltage conductors.

31. 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.

32. 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.

33. 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.

34. 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.

35. 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.

36. 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 ________ day of September, 2017.

____
PORTLAND GENERAL ELECTRIC COMPANY

____
STAFF OF THE PUBLIC UTILITY COMMISSION OF OREGON

____
OREGON CITIZENS' UTILITY BOARD

____
INDUSTRIAL CUSTOMERS OF NORTHWEST UTILITIES

____
THE KROGER CO.

____
WALMART STORES, INC. AND SAM'S WEST, INC.

____
SMALL BUSINESS UTILITY ADVOCATES

Portland General Electric Company
2018 Revenue Requirement - Base Business
($000)

	Rev Req	Percent
Total Increase:	32,049	1.80%

	At Current Rates	June Load Forecast Delta	GRC Change for RROE	Proposed 2018	Non-NVPC Adjustments	NVPC Adjustments	Total Results
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1 Sales to Consumers	1,783,435	8,667	91,230	1,883,332	(51,634)	(7,547)	1,824,151
2 Sales for Resale	-			-	-	-	-
3 Other Revenues	25,841			25,841	1,000	-	26,841
4 Total Operating Revenues	1,809,276		91,230	1,909,173	(50,634)	(7,547)	1,850,992
5 Net Variable Power Costs	353,586			353,586	-	(7,276)	346,310
6 Production O&M (excludes Trojan)	159,768			159,768	154	-	159,922
7 Trojan O&M	84			84	-	-	84
8 Transmission O&M	14,306			14,306	-	-	14,306
9 Distribution O&M	120,162			120,162	4	-	120,165
10 Customer & MBC O&M	75,298			75,298	(803)	-	74,495
11 Uncollectibles Expense	6,599		370	6,968	(177)	(26)	6,259
12 OPUC Fees	6,688		375	7,062	(166)	(24)	5,857
13 A&G, Ins/Bene., & Gen. Plant	164,970			164,970	(11,823)	-	153,147
14 Total Operating & Maintenance	901,459		744	902,203	(12,811)	(7,326)	880,544
15 Depreciation	317,424			317,424	(15,531)	-	301,893
16 Amortization	59,854			59,854	(1,399)	-	58,455
17 Property Tax	60,743			60,743	-	-	60,743
18 Payroll Tax	16,109			16,109	(31)	-	16,078
19 Other Taxes	2,434			2,434	-	-	2,434
20 Franchise Fees	45,397		2,543	47,939	(1,314)	(192)	46,433
21 Utility Income Tax	121,190		38,559	159,749	(6,894)	(9)	153,152
22 Total Operating Expenses & Taxes	1,524,610		41,846	1,566,457	(37,980)	(7,527)	1,519,733
23 **Utility Operating Income**	284,665		58,051	342,716	(12,654)	(20)	331,259
				342,716			331,259
24 **Average Rate Base**							
25 Avg. Gross Plant	9,879,272			9,879,272	(62,746)	-	9,816,526

26 Avg. Accum. Deprec. / Amort	(4,735,925)		(4,735,925)	8,172	-	(4,727,753)
27 Avg. Accum. Def Tax	(634,410)		(634,410)	(27,861)	-	(662,272)
28 Avg. Accum. Def ITC	-		-	-	-	-
29 **Avg. Net Utility Plant**	4,508,938	-	4,508,938	(82,435)	-	4,426,502
30 Misc. Deferred Debits	20,863		20,863	(3,923)	-	16,940
31 Operating Materials & Fuel	80,737		80,737	-	-	80,737
32 Misc. Deferred Credits	(73,318)		(73,318)	-	-	(73,318)
33 Working Cash	55,314	1,518	56,833	(1,378)	(273)	55,137
34 **Average Rate Base**	4,592,534	1,518	4,594,052	(87,736)	(273)	4,505,999
35 **Rate of Return**	6.198%		7.460%		7.351%	7.352%
36 **Implied Return on Equity**	7.227%		9.750%		9.500%	9.500%
37 Effective Cost of Debt	5.170%	5.170%	5.170%	5.203%	5.203%	5.203%
38 Effective Cost of Preferred	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%
40 Preferred Share of Cap Structure	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%
41 Weighted Cost of Debt	2.585%	2.585%	2.585%	2.602%	2.602%	2.602%
42 Weighted Cost of Preferred	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%
44 State Tax Rate	7.582%	7.582%	7.582%	7.582%	7.582%	7.582%
45 Federal Tax Rate	35.000%	35.000%	35.000%	35.000%	35.000%	35.000%
46 Composite Tax Rate	39.928%	39.928%	39.928%	39.928%	39.928%	39.928%
47 Bad Debt Rate	0.370%	0.370%	0.370%	0.343%	0.343%	0.343%
48 Franchise Fee Rate	2.545%	2.545%	2.545%	2.545%	2.545%	2.545%
49 Working Cash Factor	3.628%	3.628%	3.628%	3.628%	3.628%	3.628%
50 Gross-Up Factor	1.665	1.665	1.665	1.665	1.665	1.665
51 ROE Target	9.750%	9.750%	9.750%	9.500%	9.500%	9.500%
52 Grossed-Up COC	10.700%	10.700%	10.700%	10.509%	10.509%	10.509%
53 OPUC Fee Rate	0.3750%	0.375%	0.375%	0.321%	0.321%	0.321%
Utility Income Taxes						
54 Book Revenues	1,809,276	99,897	1,909,173	(50,634)	(7,547)	1,850,992
55 Book Expenses	1,403,420	3,287	1,406,707	(31,086)	(7,518)	1,366,581
56 Interest Deduction	118,717	39	118,756	(2,282)	(7)	117,224
57 Production Deduction	9,000		9,000	-		9,000
58 Permanent Ms	(24,268)		(24,268)	-		(24,268)
59 Deferred Ms	45,835		45,835	-		45,835
60 Taxable Income	256,572	96,571	353,143	(17,265)	(22)	336,621

61 Current State Tax	20,136	7,322	27,459	(1,309)	(2)	26,206
62 State Tax Credits	-		-	-		-
63 Net State Taxes	20,136	7,322	27,459	(1,309)	(2)	26,206
64 Federal Taxable Income	236,436	89,249	325,684	(15,956)	(20)	310,415
65 Current Federal Tax	82,752	31,237	113,989	(5,585)	(7)	108,645
66 Federal Tax Credits	-		-	-		-
67 ITC Amort	-	-	-	-		-
68 Deferred Taxes	18,301	0	18,301	-	-	18,301
69 Total Income Tax Expense	121,190	38,559	159,749	(6,894)	(9)	153,152
70 Regulated Net Income	165,948		223,960			214,035
71 Check Regulated NI			223,960			214,035