BEFORE THE WASHINGTON
UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION, Complainant, v. PUGET SOUND ENERGY, Respondent.	DOCKETS UE-170033 & UG-170034 MULTIPARTY SETTLEMENT STIPULATION AND AGREEMENT

I. INTRODUCTION

1. This Settlement Stipulation and Agreement ("Settlement") is entered into by and between the following parties in this case: (i) Puget Sound Energy ("PSE"), (ii) the Commission's regulatory staff ("Commission Staff"),[1] (iii) the Industrial Customers of Northwest Utilities ("ICNU"), (iv) NW Energy Coalition/Renewable Northwest/Natural Resource Defense Council, (v) The Energy Project, (vi) Sierra Club, (vii) Federal Executive Agencies, (viii) The Kroger Co., (ix) the State of Montana, and (x) Northwest Industrial Gas Users ("NWIGU") as of September 15, 2017 (the "Settlement Date"). These parties are hereinafter collectively referred to as "Settling Parties" and individually as a "Settling Party."

2. This Settlement is a "multiparty settlement," as that term is defined in WAC 480-07-730(3), because this Settlement is entered into by some, but not all, parties on one or more issues.

[1] In formal proceedings, such as this, the Commission's regulatory staff participates like any other party, while the Commissioners make the decision. To assure fairness, the Commissioners, the presiding administrative law judge, and the Commissioners' policy and accounting advisors do not discuss the merits of this proceeding with the regulatory staff, or any other party, without giving notice and opportunity for all parties to participate. *See* RCW 34.05.455.

3. This Settlement is subject to review and disposition by the Washington Utilities and Transportation Commission ("Commission"). Section III of the Settlement is effective on the date of the Commission order approving it (unless the Commission establishes a different effective date).

II. BACKGROUND AND NATURE OF THE DOCKET

4. On January 13, 2017, PSE filed with the Commission, in Dockets UE-170033 & UG-170034, tariff revisions to increase rates for electric and natural gas services provided to customers in Washington. The tariff revisions, if allowed to become effective, would have increased electric base rates by approximately $149 million (7.6 percent) on an annual basis and increased natural gas base rates by approximately $23 million (2.8 percent) on an annual basis. The net impact to customers after applying various offsets would be an increase in electric rates of approximately $87 million (4.1 percent) and a decrease in natural gas rates of approximately $22 million (–2.4 percent). The Commission suspended operation of the as-filed tariffs and set the matters for hearing in Order 01 on January 19, 2017. The Commission convened a prehearing conference in this proceeding at Olympia, Washington on February 13, 2017.

5. At various times established in its procedural schedule, and by several orders, the Commission accepted prefiled testimony and exhibits from PSE, Commission Staff, and other parties. The parties to the proceeding participated in settlement conferences on August 11, 2017, and August 24, 2017, and have participated in subsequent settlement-related calls and correspondence after those dates. On August 25, 2017, the Settling Parties reached an agreement in principle for the settlement on some, but not all issues, and agreed that remaining issues may be litigated and provided notice of this agreement in principle to Administrative Law Judge Moss.

6. On August 30, 2017, the Commission conducted evidentiary hearings on the remaining issues not resolved in the agreement in principle among the Settling Parties. In addition, the Commission conducted public comment hearings in PSE's service territory on July 31, 2017, and on August 31, 2017, during which the Commission received into the record oral comments and exhibits from interested members of the public.

III. AGREEMENT

A. Capital Structure and Cost of Capital

1. Capital Structure

7. The Settling Parties agree to a capital structure for PSE that includes 48.5 percent equity and 51.5 percent debt.

2. Cost of Equity

8. The Settling Parties agree to an authorized return on equity for PSE of 9.50 percent.

3. Costs of Debt

9. The Settling Parties agree to an authorized cost of debt for PSE of 5.81 percent.

4. Authorized Rate of Return

10. The Settling Parties agree to an overall authorized rate of return for PSE of 7.60 percent, as reflected in Table 1 below.

Table 1. Authorized Rate of Return

	Capital Structure	**Cost**	**Weighted Cost**
Debt	51.5%	5.81%	2.99%
Equity	48.5%	9.50%	4.61%
Overall Rate of Return	100.0%		7.60%

B. Revenue, Expense and Rate Base Restating and Pro Forma Adjustments

11. The Settling Parties agree to an overall electric revenue increase of $20 million (or 0.9 percent increase) and an overall natural gas revenue decrease of $35 million (or 3.8 percent decrease). For purposes of this Section III.B, the Settling Parties used as a common base (i) the Electric Results of Operations for the Twelve Months Ended September 30, 2016, as presented by Ms. Melissa Cheesman in Exh. MCC-2r, and (ii) the Gas Results of Operations for the Twelve Months Ended September 30, 2016, as presented by Ms. Melissa Cheesman in Exh. MCC-7r. All adjustment numbers and nomenclature in this Section III.B are identical to those presented in Exh. MCC-2r for electric operations and Exh. MCC-7r for natural gas operations. Additionally, the Settling Parties present a table of all agreed-upon revenue, expense and rate base restating and pro forma adjustments consistent with this Settlement as Exhibit A to this Settlement.

1. Actual Results of Operations

a. Actual Results of Operations for Electric Operations

12. The actual results of electric operations for the test year are uncontested and consist of (i) net operating income of $401,002,972 and (ii) rate base of $5,153,204,462. (*See, e.g.*, Cheesman, Exh. MCC-2r at 2.)

b. Actual Results of Operations for Natural Gas Operations

13. The actual results of natural gas operations for the test year are uncontested and consist of (i) net operating income of $119,145,769 and (ii) rate base of $1,727,319,760. (*See, e.g.*, Cheesman, Exh. MCC-7r at 2.)

2. Common Adjustments

a. Revenues and Expenses

i. Adjustment No. 13.01 – Revenues and Expenses (Electric)

14. Adjustment No. 13.01 – Revenues and Expenses is uncontested and decreases net operating income for electric operations by $29,139,114. (*See, e.g.,* Cheesman, Exh. MCC-2r at 2.)

ii. Adjustment No. 11.01 – Revenues and Expenses (Natural Gas)

15. Adjustment No. 11.01 – Revenues and Expenses is uncontested and decreases net operating income for natural gas operations by $32,674,131. (*See, e.g.,* Cheesman, Exh. MCC-7r at 2.)

b. Temperature Normalization

i. Adjustment No. 13.02 – Temperature Normalization (Electric)

16. The Settling Parties accept, for purpose of settlement, Adjustment No. 13.02 – Temperature Normalization proposed by PSE, which increases net operating income for electric operations by $17,527,344. (*See* Barnard, Exh. KJB-19 at 2 (labeled therein as "Adjustment No. 20.02 – Temperature Normalization").) The Settling Parties do not agree to any methodology for temperature normalization going forward and expressly reserve the right to address similar modifications in subsequent proceedings.

ii. Adjustment No. 11.02 – Temperature Normalization (Natural Gas)

17. The Settling Parties accept, for purposes of settlement, Adjustment No. 11.02 – Temperature Normalization proposed by PSE, which increases net operating income for natural gas operations by $16,046,445. (*See* Free, Exh. SEF-14 at 2 (labeled therein as "Adjustment No. 15.02 – Temperature Normalization").) The Settling Parties do not agree to any

methodology for temperature normalization going forward and expressly reserve the right to address similar modifications in subsequent proceedings.

c. Pass-Through Revenues and Expenses

i. Adjustment No. 13.03 – Pass-Through Revenues and Expenses (Electric)

18. Adjustment No. 13.03 – Pass-Through Revenues and Expenses is uncontested and decreases net operating income for electric operations by $1,000,540. (*See, e.g.,* Cheesman, Exh. MCC-2r at 2.)

ii. Adjustment No. 11.03 – Pass-Through Revenues and Expenses (Natural Gas)

19. Adjustment No. 11.03 – Pass-Through Revenues and Expenses is uncontested and increases net operating income for natural gas operations by $736,148. (*See, e.g.,* Cheesman, Exh. MCC-7r at 2.)

d. Federal Income Tax

i. Adjustment No. 13.04 – Federal Income Tax (Electric)

20. Adjustment No. 13.04 – Federal Income Tax is uncontested and decreases net operating income for electric operations by $27,023,239. (*See, e.g.,* Cheesman, Exh. MCC-2r at 2.)

ii. Adjustment No. 11.04 – Federal Income Tax (Natural Gas)

21. Adjustment No. 11.04 – Federal Income Tax is uncontested and increases net operating income for natural gas operations by $700,822. (*See, e.g.,* Cheesman, Exh. MCC-7r at 2.)

e. Tax Benefit of Pro Forma Interest

i. Adjustment No. 13.05 – Tax Benefit of Pro Forma Interest (Electric)

22. No party contested the manner in which Adjustment No. 13.05 – Tax Benefit of Pro Forma Interest should be calculated, although parties differed in the result based on the rate base items included. Based upon the rate base items included in this Settlement, the Settling Parties agree that Adjustment No. 13.05 – Tax Benefit of Pro Forma Interest increases net operating income for electric operations by $54,067,781. [2]

ii. Adjustment No. 11.05 – Tax Benefit of Pro Forma Interest (Natural Gas)

23. No party contested the manner in which Adjustment No. 11.05 – Tax Benefit of Pro Forma Interest should be calculated, although parties differed in the result based on the rate base items included. Based upon the rate base items included in this Settlement, the Settling Parties agree that Adjustment No. 11.05 – Tax Benefit of Pro Forma Interest increases net operating income for natural gas operations by $18,475,298.[3]

f. Depreciation Study

i. Adjustment No. 13.06 – Depreciation Study (Electric)

24. The Settling Parties agree to use the depreciation study provided by PSE as the Second Exhibit to the Prefiled Direct Testimony of Mr. John J. Spanos, Exhibit JJS-3r, subject to modifications with respect to (i) Colstrip Units 1 and 2 identified in paragraph 25 below and (ii) Colstrip Units 3 and 4 identified in paragraph 26 below. Please see Exhibit B to this

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[2] Adjustment No. 13.05 – Tax Benefit of Pro Forma Interest is equal to the product of (i) electric rate base of $5,166,534,272, multiplied by (ii) the weighted average cost of debt of 2.99%, multiplied by (ii) the federal tax rate of 35 percent.

[3] Adjustment No. 11.05 – Tax Benefit of Pro Forma Interest is equal to the product of (i) natural gas rate base of $1,765,436,979, multiplied by (ii) the weighted average cost of debt of 2.99%, multiplied by (ii) the federal tax rate of 35 percent.

Settlement for the electric depreciation study adjustment and the agreed-upon electric depreciation rates that result from this Settlement.

25. The Settling Parties agree to set depreciation rates for Colstrip Units 1 and 2 at amounts that will yield annual depreciation expense of $18.5 million for the remaining operational lives of those units. The resulting depreciation rates are included on pages 12 and 13 of Exhibit B to this Settlement. At closure of Units 1 and 2, PSE shall offset all additional unrecovered plant balances for Colstrip Units 1 and 2 with monetized production tax credits ("PTCs"). PSE assumes the risk that it is unable to monetize the PTCs to offset additional unrecovered plant balances for Colstrip Units 1 and 2; provided, however that if Colstrip Units 1 and 2 close prior to the monetization of sufficient PTCs to offset additional unrecovered plant balances for Colstrip Units 1 and 2, PSE shall hold remaining unrecovered plant balances of Colstrip Units 1 and 2 in a regulatory asset in rate base until the earlier to occur of (i) the recovery of all plant balances for Colstrip Units 1 and 2 through monetized PTC offsets or (ii) December 31, 2029.

26. The Settling Parties agree to a depreciation schedule for Colstrip Units 3 and 4 that assumes a remaining useful life of those units through December 31, 2027. The Settling Parties understand that December 31, 2027, is a stipulated depreciation life for Colstrip Units 3 and 4. The resulting depreciation rates for Units 3 and 4 are included on pages 2 and 3 of Exhibit B to this Settlement.

27. The Settling Parties agree that Adjustment No. 13.06 – Depreciation Study (i) decreases net operating income for electric operations by $34,311,788 and (ii) decreases rate base for electric operations by $17,155,894, as is shown on page 1 of Exhibit B to this Settlement.

ii. Adjustment No. 11.06 – Depreciation Study (Natural Gas)

28. The Settling Parties agree to use the depreciation study provided by PSE as the Second Exhibit to the Prefiled Direct Testimony Mr. John J. Spanos, Exhibit JJS-3r. The Settling Parties further agree that Adjustment No. 11.06 – Depreciation Study is uncontested for natural gas operations and (i) increases net operating income for natural gas operations by $13,174,098 and (ii) increases rate base for natural gas operations by $6,587,049. (*See*, *e.g.*, Cheesman, Exh. MCC-7r at 2.)

g. Regulatory Asset Colstrip

29. The Settling Parties agree not to use Adjustment No. 13.06A – Reg. Asset Colstrip proposed by Commission Staff. Accordingly, Adjustment No. 13.06A – Reg. Asset Colstrip has no effect on either net operating income or rate base for electric operations.

h. Normalize Injuries and Damages

i. Adjustment No. 13.07 – Normalize Injuries and Damages (Electric)

30. Adjustment No. 13.07 – Normalize Injuries and Damages is uncontested and increases net operating income for electric operations by $69,387. (*See, e.g.,* Cheesman, Exh. MCC-2r at 3.)

ii. Adjustment No. 11.07 – Normalize Injuries and Damages (Natural Gas)

31. Adjustment No. 11.07 – Normalize Injuries and Damages is uncontested and decreases net operating income for natural gas operations by $57,738. (*See, e.g.,* Cheesman, Exh. MCC-7r at 2.)

i. Bad Debts

i. Adjustment No. 13.08 – Bad Debts (Electric)

32. Adjustment No. 13.08 – Bad Debts is uncontested and increases net operating income for electric operations by $681,065. (*See, e.g.*, Cheesman, Exh. MCC-2r at 3.)

ii. Adjustment No. 11.08 – Bad Debts (Natural Gas)

33. Adjustment No. 11.08 – Bad Debts is uncontested and increases net operating income for natural gas operations by $35,240. (*See, e.g.*, Cheesman, Exh. MCC-7r at 3.)

j. Incentive Pay

i. Adjustment No. 13.09 – Incentive Pay (Electric)

34. Adjustment No. 13.09 – Incentive Pay is uncontested and decreases net operating income for electric operations by $109,903. (*See, e.g.*, Cheesman, Exh. MCC-2r at 3.)

ii. Adjustment No. 11.09 – Incentive Pay (Natural Gas)

35. Adjustment No. 11.09 – Incentive Pay is uncontested and increases net operating income for natural gas operations by $104,023. (*See, e.g.*, Cheesman, Exh. MCC-7r at 3.)

k. Directors & Officers Insurance

i. Adjustment No. 13.10 – Directors & Officers Insurance (Electric)

36. Adjustment No. 13.10 – Directors & Officers Insurance is uncontested and increases net operating income for electric operations by $16,141. (*See, e.g.*, Cheesman, Exh. MCC-2r at 3.)

ii. Adjustment No. 11.10 – Directors & Officers Insurance (Natural Gas)

37. Adjustment No. 11.10 – Directors & Officers Insurance is uncontested and increases net operating income for natural gas operations by $11,636. (*See, e.g.*, Cheesman, Exh. MCC-7r at 3.)

l. Interest on Customer Deposits

i. Adjustment No. 13.11 – Interest on Customer Deposits (Electric)

38. Adjustment No. 13.11 – Interest on Customer Deposits is uncontested and decreases net operating income for electric operations by $176,606. (*See, e.g.,* Cheesman, Exh. MCC-2r at 3.)

ii. Adjustment No. 11.11 – Interest on Customer Deposits (Natural Gas)

39. Adjustment No. 11.11 – Interest on Customer Deposits is uncontested and decreases net operating income for natural gas operations by $50,137. (*See, e.g.,* Cheesman, Exh. MCC-7r at 3.)

m. Rate Case Expenses

i. Adjustment No. 13.12 – Rate Case Expenses (Electric)

40. The Settling Parties agree to use Adjustment No. 13.12 – Rate Case Expenses proposed by PSE, which decreases net operating income for electric operations by $264,905. (*See* Barnard, Exh. KJB-19 at 3 (labeled therein as "Adjustment No. 20.12 – Rate Case Expenses").)

ii. Adjustment No. 11.12 – Rate Case Expenses (Natural Gas)

41. The Settling Parties agree to use Adjustment No. 11.12 – Rate Case Expenses proposed by PSE, which decreases net operating income for natural gas operations by $280,617. (*See* Free, Exh. SEF-14 at 3 (labeled therein as "Adjustment No. 15.12 – Rate Case Expenses").)

n. Deferred Gains/Losses on Property Sales

i. Adjustment No. 13.13 – Deferred Gains/Losses on Property Sales (Electric)

42. Adjustment No. 13.13 – Deferred Gains/Losses on Property Sales is uncontested and increases net operating income for electric operations by $171,200. (*See, e.g.*, Cheesman, Exh. MCC-2r at 3.)

ii. Adjustment No. 11.13 – Deferred Gains/Losses on Property Sales (Natural Gas)

43. The Settling Parties agree to use Adjustment No. 11.13 – Deferred Gains/Losses on Property Sales proposed by PSE, which decreases net operating income for natural gas operations by $105,090. (*See* Free, Exh. SEF-14 at 3 (labeled therein as "Adjustment No. 15.13 – Deferred Gains/Losses on Property Sales").)

o. Property & Liability Insurance

i. Adjustment No. 13.14 – Property & Liability Insurance (Electric)

44. Adjustment No. 13.14 – Property & Liability Insurance is uncontested and increases net operating income for electric operations by $66,147. (*See, e.g.*, Cheesman, Exh. MCC-2r at 4.)

ii. Adjustment No. 11.14 – Property & Liability Insurance (Natural Gas)

45. Adjustment No. 11.14 – Property & Liability Insurance is uncontested and increases net operating income for natural gas operations by $45,174. (*See, e.g.*, Cheesman, Exh. MCC-7r at 3.)

p. Pension Plan

i. Adjustment No. 13.15 – Pension Plan (Electric)

46. The Settling Parties agree to use Adjustment No. 13.15 – Pension Plan proposed by each of PSE and Commission Staff, which decreases net operating income for electric operations by $1,184,945. (*See, e.g.*, Cheesman, Exh. MCC-2r at 4; Barnard, Exh. KJB-19 at 4 (labeled therein as "Adjustment No. 20.15 – Pension Plan").)

ii. Adjustment No. 11.15 – Pension Plan (Natural Gas)

47. The Settling Parties agree to use the Adjustment No. 11.15 – Pension Plan proposed by each of PSE and Commission Staff, which decreases net operating income for natural gas operations by $572,091. (*See, e.g.*, Cheesman, Exh. MCC-7r at 3; Free, Exh. SEF-14 at 3 (labeled therein as "Adjustment No. 15.15 – Pension Plan").)

q. Wage Increase

i. Adjustment No. 13.16 – Wage Increase (Electric)

48. Adjustment No. 13.16 – Wage Increase is uncontested and decreases net operating income for electric operations by $1,357,716. (*See, e.g.*, Cheesman, Exh. MCC-2r at 4.)

ii. Adjustment No. 11.16 – Wage Increase (Natural Gas)

49. Adjustment No. 11.16 – Wage Increase is uncontested and decreases net operating income for natural gas operations by $907,409. (*See, e.g.*, Cheesman, Exh. MCC-7r at 3.)

r. Investment Plan

i. Adjustment No. 13.17 – Investment Plan (Electric)

50. Adjustment No. 13.17 – Investment Plan is uncontested and decreases net operating income for electric operations by $96,705. (*See, e.g.*, Cheesman, Exh. MCC-2r at 4.)

ii. Adjustment No. 11.17 – Investment Plan (Natural Gas)

51. Adjustment No. 11.17 – Investment Plan is uncontested and decreases net operating income for natural gas operations by $46,689. (*See, e.g.,* Cheesman, Exh. MCC-7r at 3.)

s. Employee Insurance

i. Adjustment No. 13.18 – Employee Insurance (Electric)

52. Adjustment No. 13.18 – Employee Insurance is uncontested and decreases net operating income for electric operations by $121,751. (*See, e.g.,* Cheesman, Exh. MCC-2r at 4.)

ii. Adjustment No. 11.18 – Employee Insurance (Natural Gas)

53. Adjustment No. 11.18 – Employee Insurance is uncontested and decreases net operating income for natural gas operations by $58,781. (*See, e.g.,* Cheesman, Exh. MCC-7r at 4.)

t. Environmental Remediation

i. General Provisions Related to Environmental Remediation

54. Within six months of filing of this Settlement with the Commission, PSE and Commission Staff shall commence a process to determine a methodology for assigning insurance recoveries received by PSE in a manner that does not potentially compromise PSE's litigation position associated with such insurance recoveries. PSE and Commission Staff shall provide an update regarding such process in the earlier to occur of either (i) PSE's next general rate case proceeding or (ii) any expedited rate filing ("ERF") or limited rate proceeding of PSE to revise transmission and distribution rates.

55. In lieu of quarterly environmental reports, PSE shall submit annual environmental reports no later than April 30 of the following year that contain the following information:

(a) Project amounts authorized for deferral with the Commission docket and order number that gives authority to PSE to do so.

(b) Beginning date of the deferral of each project.

(c) Beginning balances at the start of deferral.

(d) Monthly balances and the year-end deferred balance for the reporting year.

(e) Location of projects and internal naming convention (e.g., Tacoma Tar Pits and/or Tide Flats).

(f) Total amount of third party and insurance recoveries received during the reporting year by month. Where possible, recoveries received by PSE will reduce the balance of corresponding project cost balances. If PSE receives lump sums for multiple projects, documentation that supports all the projects that caused the claim against third party and insurance should be included in the report.

(g) PSE shall record costs incurred for newly established electric and gas remediation sites in FERC account 186. Balances of projects that have been authorized for amortization and are currently being amortized should be transferred to FERC account 182.3. All projects that are newly established or are being amortized should be included in the annual report to the Commission, along with Commission's order that authorized deferral number, Commission's order that authorized amortization, beginning balances when the amortization started, year end balances, and amortization start and end date.

Notwithstanding the foregoing, after the conclusion of the process for assigning insurance recoveries conducted pursuant to paragraph 54 of this Settlement, PSE shall report specific recoveries associated with specific projects consistent with the terms and conditions developed in such process.

ii. Adjustment No. 13.19 – Environmental Remediation (Electric)

56. The Settling Parties agree to use Adjustment No. 13.19 – Environmental Remediation proposed by PSE, which decreases net operating income for electric operations by

$925,460. (*See* Barnard, Exh. KJB-19 at 4 (labeled therein as "Adjustment No. 20.19 – Environmental Remediation").)

iii. Adjustment No. 11.19 – Environmental Remediation (Natural Gas)

57. The Settling Parties agree to use Adjustment No. 11.19 – Environmental Remediation proposed by PSE, which decreases net operating income for natural gas operations by $5,592,128. (*See* Free, Exh. SEF-14 at 4 (labeled therein as "Adjustment No. 15.19 – Environmental Remediation").)

u. Payment Processing Costs

i. Adjustment No. 13.20 – Payment Processing Costs (Electric)

58. The Settling Parties agree to use Adjustment No. 13.20 – Payment Processing Costs proposed by PSE, Public Counsel, and Commission Staff, which decreases net operating income for electric operations by $2,010,221. (*See*, *e.g.*, Cheesman, Exh. MCC-2r at 4.)

ii. Adjustment No. 11.20 – Payment Processing Costs (Natural Gas)

59. The Settling Parties agree to use Adjustment No. 11.20 – Payment Processing Costs proposed by PSE, Public Counsel, and Commission Staff, which decreases net operating income for natural gas operations by $1,449,117. (*See, e.g.*, Cheesman, Exh. MCC-7r at 4.)

v. South King Service Center

i. Adjustment No. 13.21 – South King Service Center (Electric)

60. Adjustment No. 13.21 – South King Service Center is uncontested and (i) increases net operating income for electric operations by $434,046 and (ii) increases rate base for electric operations by $15,915,060. (*See, e.g.*, Cheesman, Exh. MCC-2r at 4.)

ii. Adjustment No. 11.21 – South King Service Center (Natural Gas)

61. Adjustment No. 11.21 – South King Service Center is uncontested and (i) increases net operating income for natural gas operations by $212,048 and (ii) increases rate base for natural gas operations by $7,775,116. (*See, e.g.*, Cheesman, Exh. MCC-7r at 4.)

w. Excise Tax and WUTC Filing Fee

i. Adjustment No. 13.22 – Excise Tax and WUTC Filing Fee (Electric)

62. Adjustment No. 13.22 – Excise Tax and WUTC Filing Fee is uncontested and increases net operating income for electric operations by $10,262. (*See, e.g.,* Cheesman, Exh. MCC-2r at 4.)

ii. Adjustment No. 11.22 – Excise Tax and WUTC Filing Fee (Natural Gas)

63. Adjustment No. 11.22 – Excise Tax and WUTC Filing Fee is uncontested and increases net operating income for natural gas operations by $33,509. (*See, e.g.,* Cheesman, Exh. MCC-7r at 4.)

x. Investor-Supplied Working Capital and Rate Base Adjustment

i. Adjustment No. 13.23 – ISWC and RB Adjustment (Electric)

64. The Settling Parties agree to base Adjustment No. 13.23 – ISWC and RB Adjustment on Adjustment 20.23 – Working Capital proposed by PSE; *provided, however*, that PSE shall include construction work in progress ("CWIP") in the non-operating category for purposes of allocating investor-supplied working capital among electric, gas, and non-utility operations. The calculation of investor-supplied working capital agreed to by the Settling Parties is included as Exhibit C to this Settlement. The Settling Parties agree that Adjustment

No. 13.23 – ISWC and RB Adjustment increases rate base for electric operations by $19,006,090.

ii. Adjustment No. 11.23 – ISWC and RB Adjustment (Natural Gas)

65. The Settling Parties agree to base Adjustment No. 11.23 – ISWC and RB Adjustment on Adjustment 15.23 – Working Capital proposed by PSE; *provided, however*, that PSE shall include CWIP in the non-operating category for purposes of allocating investor-supplied working capital among electric, gas, and non-utility operations. The calculation of investor-supplied working capital agreed to by the Settling Parties is included as Exhibit C to this Settlement. The Settling Parties agree that Adjustment No. 11.23 – ISWC and RB Adjustment increases rate base for natural gas operations by $4,743,346.

y. Legal Cost

i. Adjustment No. 13.24 – Legal Cost (Electric)

66. The Settling Parties agree not to make Adjustment No. 13.24 – Legal Cost proposed by Commission Staff. Accordingly, Adjustment No. 13.24 – Legal Cost has no effect on either net operating income or rate base for electric operations.

ii. Adjustment No. 11.24 – Legal Cost (Natural Gas)

67. The Settling Parties agree not to use Adjustment No. 11.24 – Legal Cost proposed by Commission Staff. Accordingly, Adjustment No. 11.24 – Legal Cost has no effect on either net operating income or rate base for natural gas operations.

z. Black Box Adjustment

i. Adjustment No. 13.25 – Black Box Adjustment (Electric)

68. The Settling Parties agree to Adjustment No. 13.25 – Black Box Adjustment, which decreases the revenue requirement for electric operations by $1 million to address all

remaining electric revenue requirement issues that differ from PSE's rebuttal case filed in this proceeding on August 9, 2017. Each of the Settling Parties reserves its right to make arguments on methodologies for these and other issues in future cases without prejudice. Adjustment No. 13.25 – Black Box Adjustment increases net operating income for electric operations by $619,051, which is equal to the product of (i) $1,000,000, multiplied by (ii) the electric conversion factor of 0.952386,[4] multiplied by (iii) the difference between (a) 100 percent, minus (b) the federal tax rate of 35 percent.

ii. Adjustment No. 11.25 – Black Box Adjustment (Natural Gas)

69. The Settling Parties agree to Adjustment No. 11.25 – Black Box Adjustment, which decreases the revenue requirement for natural gas operations by $1.5 million to address all remaining natural gas revenue requirement issues that differ from PSE's rebuttal case filed in this proceeding on August 9, 2017. Each of the Settling Parties reserves its right to make arguments on methodologies for these and other issues in future cases without prejudice. Adjustment No. 11.25 – Black Box Adjustment increases net operating income for natural gas operations by $930,675, which is equal to the product of (i) $1,500,000, multiplied by (ii) the electric conversion factor of 0.954538,[5] multiplied by (iii) the difference between (a) 100 percent, minus (b) the federal tax rate of 35 percent.

3. Electric-Only Adjustments

a. Adjustment No. 14.01 – Power Costs

70. The Settling Parties agree to base Adjustment No. 14.01 – Power Costs as proposed by PSE in Adjustment 21.01– Power Costs, subject to the following modifications:

(i) PSE shall remove all costs associated with compliance with the Clean Air Rule from power costs in this proceeding;

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[4] *See, e.g.*, Cheesman, Exh. MCC-3r at 3.

[5] *See, e.g.*, Cheesman, Exh. MCC-8r at 3.

(ii) PSE shall use the same wind resource capacity factors used to determine power costs for purposes of establishing rates in Docket UE-111048 to determine power costs in this proceeding; and

(iii) PSE shall remove major maintenance adders from the AURORA dispatch model in determining power costs in this proceeding.

(iv) PSE shall remove both the costs and benefits associated with the California Independent System Operator ("CAISO") Energy Imbalance Market ("EIM").

The Settling Parties acknowledge that these modifications represent a compromise for settlement purposes only, and each Settling Party expressly reserves the right to advocate different positions in subsequent proceedings.

71. The Settling Parties support approval of a deferral mechanism in this proceeding, by which PSE will be allowed to defer Clean Air Rule compliance costs for future recovery once Clean Air Rule compliance requirements and obligations are finally determined. This will depend on (i) the timing of when Clean Air Rule compliance costs become known and measurable and (ii) the materiality of such compliance costs, the Settling Parties that intend to take a position on this issue will work together to include prudent Clean Air Rule costs in PSE's Power Cost Adjustment ("PCA") baseline rate as expeditiously as possible.

72. The Settling Parties agree that the moratorium on changes to the PCA mechanism adopted in Docket UE-130617 shall remain in effect. For purposes of this Settlement, however, the Settling Parties agree to Commission Staff's proposal that a line item for all costs related to the CAISO EIM be included as actual costs in the annual PCA filing that determines whether PSE over- or under-collected on power costs. For purposes of calculating the PCA imbalance in the PCA mechanism, the Settling Parties agree to include the amount for capital items (depreciation and return on) and labor related to the CAISO EIM included in Exhibit D to this Settlement as a line-item in actual allowed power costs in Schedule B. PSE shall include these

costs in Schedule B in a manner similar to the Equity Adder for the Coal Transition PPA in that they will be included in the Adjustments section (currently shown on lines 52 through 57 in PSE's 2016 Annual PCA Compliance Filing in Docket No. UE-170334) of Schedule B. These rows adjust the variable costs associated with power costs not represented in actual expenses booked to the power cost accounts.

73. The Settling Parties agree that Adjustment No. 14.01 – Power Costs increases net operating income for electric operations by $1,185,175, the calculation of which is provided as Exhibit E to this Settlement.

b. Adjustment No. 14.02 – Montana Electric Energy Tax

74. No party contested the manner in which Adjustment No. 14.02 – Montana Electric Energy Tax should be calculated, but changes to power costs affect the associated taxes. The impact of this increases net operating income for electric operations by $148,016. Please see Exhibit E to this Settlement for the calculation of Adjustment No. 14.02 – Montana Electric Energy Tax.

c. Adjustment No. 14.03 – Wild Horse Solar

75. Adjustment No. 14.03 – Wild Horse Solar is uncontested and (i) increases net operating income for electric operations by $137,890 and (ii) decreases rate base for electric operations by $1,969,341. (*See, e.g.,* Cheesman, Exh. MCC-2r at 5.)

d. Adjustment No. 14.04 – ASC 815 (Prev. SFAS 133)

76. Adjustment No. 14.04 – ASC 815 (Prev. SFAS 133) is uncontested and decreases net operating income for electric operations by $41,672,584. (*See, e.g.,* Cheesman, Exh. MCC-2r at 5.)

e. Adjustment No. 14.05 – Storm Damage

77. PSE shall defer the costs of any storms that occur on or after the Settlement Date and on or before December 31, 2017, under the terms of the storm loss deferral mechanism established in Order 6 in Dockets UE-040641 & UG-040640, *et al.*, and as revised in Order 12 in Dockets UE-072300 & UG-072301 (the "Qualifying Storm Loss Deferral Mechanism"). PSE shall propose amortization of any such storm costs deferred pursuant to the terms of the prior sentence for recovery in PSE's next general rate case or any ERF or limited rate proceeding to revise transmission and distribution rates.

78. PSE shall retain the Qualifying Storm Loss Deferral Mechanism for any storm costs incurred on or after January 1, 2018, subject to the following modifications: (i) the cumulative annual cost threshold for deferral of storms under the Qualifying Storm Loss Deferral Mechanism shall be increased from $8 million to $10 million, (ii) qualifying events that cost less than $500,000 will not qualify for deferral, and (iii) the cumulative annual cost threshold for the Qualifying Storm Loss Deferral Mechanism shall exclude storm events with costs less than $500,000.

79. The Settling Parties agree to a six-year average of $10,656,246 million for normalized storm expense.

80. The Settling Parties acknowledge that PSE has an over-amortization of $12,560,038 associated with the 2010 storms. PSE shall use the over-amortization to absorb the remaining balance of December 2006 wind storm and the remaining balance of the over-amortization to reduce the balance of the January 2012 snowstorm. PSE shall amortize remaining storm deferrals, over four years, once approved for recovery in rates; provided, however, that PSE shall amortize the January 2012 snowstorm over six years.

81. The Settling Parties agree that PSE shall calculate normalized operating income, for purposes of PSE's Earnings Sharing Mechanism by removing the storm normalization adjustment from PSE's annual Commission Basis Report per WAC 480-100-257.

82. The Settling Parties agree that Adjustment No. 14.05 – Storm Damage decreases net operating income for electric operations by $6,137,438, the calculation of which is provided as Exhibit F to this Settlement.

f. Adjustment No. 14.06 – Regulatory Assets and Liabilities

83. Adjustment No. 14.06 – Regulatory Assets and Liabilities is uncontested and (i) increases net operating income for electric operations by $1,736,212 and (ii) decreases rate base for electric operations by $44,085,326. (*See, e.g.*, Cheesman, Exh. MCC-2r at 5.)

g. Adjustment No. 14.07 – Glacier Battery Storage

84. Adjustment No. 14.07 – Glacier Battery Storage is uncontested and (i) decreases net operating income for electric operations by $145,490 and (ii) increases rate base for electric operations by $2,842,787. (*See, e.g.*, Cheesman, Exh. MCC-2r at 5.)

h. Adjustment No. 14.08 – Energy Imbalance Market

85. The Settling Parties agree not to make Adjustment No. 14.08 – Energy Imbalance Market proposed by PSE. Accordingly, Adjustment No. 14.08 – Energy Imbalance Market has no effect on either net operating income or rate base for electric operations.

i. Adjustment No. 14.09 – Goldendale Capacity Upgrade

86. Adjustment No. 14.09 – Goldendale Capacity Upgrade is uncontested and (i) increases net operating income for electric operations by $2,156 and (ii) increases rate base for electric operations by $18,140,954. (*See, e.g.*, Cheesman, Exh. MCC-2r at 6.)

j. Adjustment No. 14.10 – Mint Farm Capacity Upgrade

87. Adjustment No. 14.10 – Mint Farm Capacity Upgrade is uncontested and increases rate base for electric operations by $19,004,590. (*See, e.g.*, Cheesman, Exh. MCC-2r at 6.)

k. Adjustment No. 14.11 – White River

88. The Settling Parties agree to use Adjustment No. 14.11 – White River proposed by PSE, which (i) decreases net operating income for electric operations by $3,288,310 and (ii) decreases rate base for electric operations by $4,108,724. (*See* Barnard, Exh. KJB-19 at 6 (labeled therein as "Adjustment No. 21.11 – White River").)

l. Adjustment No. 14.12 – Reclass of Hydro Treasury Grants

89. The Settling Parties agree to use Adjustment No. 14.12 – Reclass of Hydro Treasury Grants proposed by PSE, which (i) decreases net operating income for electric operations by $2,131,857 and (ii) increases rate base for electric operations by $5,739,615. (*See* Barnard, Exh. KJB-19 at 6 (labeled therein as "Adjustment No. 21.12 – Reclass of Hydro Treasury Grants").)

m. Adjustment No. 14.13 – Production Adjustment

90. The Settling Parties agree to use Adjustment No. 14.13 – Production Adjustment proposed by PSE, which uses the variable production factor of 3.839 percent. The Settling Parties also agree that there should be no Fixed Production Factor used in this adjustment as a result of the agreements made in the decoupling section below. The Settling Parties agree that Adjustment No. 14.13 – Production Adjustment increases net operating income for electric operations by $32,769, the calculation of which is provided as Exhibit G to this Settlement.

4. Gas-Only Adjustment – Adjustment 7.01 – Cost Recovery Mechanism

91. Adjustment No. 7.01 – Cost Recovery Mechanism is uncontested and (i) decreases net operating income for natural gas operations by $4,003,724 and (ii) increases rate base for natural gas operations by $19,011,708. (*See, e.g.,* Cheesman, Exh. MCC-7r at 4.)

5. PCA Baseline Rate – Previously Exh. KJB-22

92. This Settlement results in a PCA baseline rate of $32.895 per MWh for PSE. Please see page 1 of Exhibit H to this Settlement for the calculation of this PCA baseline rate. PSE shall use this PCA baseline rate of $32.895 per MWh for purposes of calculating the imbalance for sharing in PSE's PCA mechanism beginning with the date rates become effective in this proceeding. Please also see Exhibit H to this Settlement for (i) a calculation of the PCA baseline rate that will results once Microsoft takes service under a special contract and (ii) a calculation of the impact on Schedule 95 rates that would occur in a filing to be made once Microsoft takes service under the special contract. Exhibit H to this Settlement represents updated information originally discussed in the Prefiled Supplemental Direct Testimony of Katherine J. Barnard, Exh. KJB-10T, at page 11, line 14, through page 13, line 23.

C. Rate Spread and Rate Design

93. The Settling Parties have advocated for a variety of methodologies the Commission might use for resolving cost of service and rate spread issues in this proceeding. Except as otherwise set forth in this Settlement, the Settling Parties have not agreed upon any particular methodology, and the Settlement does not attempt to resolve those issues. PSE, Commission Staff, and other interested parties agree to participate in good faith in the ongoing generic proceeding to address cost of service and rate spread methodologies to be used in future cases.

1. Electric Rate Spread and Rate Design

a. Electric Rate Spread

94. The Settling Parties agree to change the allocation of PSE's electric revenue deficiency for Schedules 7A, 10, 11, 12, 25, 26, 29, 31, 46, and 49 from 75 percent to 65 percent of the average rate increase.

b. Electric Schedule 25

95. The Settling Parties agree with the Kroger proposal to (i) keep the tail-block energy rate of Schedule 25 at its current level, (ii) increase the Schedule 25 basic charge as proposed by PSE, and (iii) raise demand rates (and a portion of the first block energy rates) to recover the remainder of the revenue requirement spread to this schedule.

c. Electric Schedule 40

96. The Settling Parties agree with the Commission Staff proposal that Schedule 40 should be discontinued over time. Only customers on Schedule 40 as of the Settlement Date shall remain on Schedule 40, and Schedule 40 shall be closed to new customers. Customers on Schedule 40 as of the Settlement Date may remain on Schedule 40 for a period no later than the effective date of the tariffs resulting from PSE's next general rate proceeding, and PSE will work with such existing Schedule 40 customers to transition to electric service pursuant to one or more other PSE electric rate schedules.

d. Electric Schedules 46 and 49 Demand Charges

97. The Settling Parties agree to the increase of 48 percent to the demand charges for Schedules 46 and 49 proposed by Commission Staff.

e. Microsoft Recalculation

98. The Settling Parties agree that, when Microsoft is removed from Schedule 40, the allowed revenue per customer for other schedules will be recalculated consistent with the

contingent allowed revenue calculations illustrated in Exhibit JAP-43 for all customers that continue to be a part of PSE's electric decoupling rate mechanism at such time.

f. Ardmore Substation

99. The Settling Parties agree to a one-time revenue adjustment that removes from the applicable Schedule 40 customers $250,000 of Ardmore Substation costs and reallocates such costs to other schedules. The Settling Parties acknowledge that this one-time revenue adjustment represents a compromise for settlement purposes only, and each Settling Party expressly reserves the right to address the issue of Ardmore Substation cost allocation in subsequent proceedings.

2. Natural Gas Rate Spread and Rate Design

100. The Settling Parties agree that all issues with respect to natural gas rate spread and rate design are not affected by this Settlement and are subject to litigation before the Commission.

D. Service Quality Index (SQI) No. 5

101. PSE shall revise Service Quality Index (SQI) No. 5 to establish an annual benchmark of 80 percent of calls answered within 60 seconds. The calculation will not include Integrated Voice Response System (IVR) transactions.

E. Low-Income Issues

102. The Settling Parties agree to PSE's proposal to increase the annual level of low-income electric assistance Home Energy Lifeline Program ("HELP") funding by double the corresponding overall percent rate increase to the residential electric class that is approved by the Commission in this proceeding.[6] The amount of the percentage increase to the residential electric class shall be calculated in a manner consistent with column (y) of Exhibit JAP-44. Double this

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6 The base funding for HELP of $21,200,000 was approved in Dockets UE-121697/UG-121705. Approved additions were made to this level of HELP funding on October 1, 2013; October 1, 2014; October 1, 2015; and October 1, 2016. Thus, the total funding level approved for HELP is currently $23,502,979.

percentage shall be added to the electric Schedule 129 low income tariff filings following the conclusion of this proceeding. Except for the redistribution of funds pursuant to paragraph 103, the Settling Parties agree to PSE's proposal to maintain the annual level of low-income natural gas assistance HELP funding at the same level as the current program year notwithstanding the decrease in rates for the natural gas residential class proposed in this Settlement.

103. The Settling Parties agree to PSE's proposal to change Schedule 129 tariffs so that the HELP funding will be distributed to electric and natural gas customers at 80% electric and 20% gas, respectively, going forward. PSE reserves the right to revisit this allocation in future rate proceedings. PSE will work with the Community Action Partnership agencies ("Agencies") to explore ways to adjust the allocation if necessary to target and utilize funds throughout a program year so that low-income customer needs are better met.

104. The Settling Parties agree to PSE's proposal to modify Schedule 129 for electric and natural gas service to allow senior, disabled, and other steady-income customers to certify their HELP eligibility for a two-year period. Such customers must meet the existing HELP criteria and elect to certify eligibility for two years after demonstrating a steady income that meets 150% of the federal poverty level, established by steady-income payment documentation.

105. PSE shall consult with The Energy Project and Agencies jointly regarding any initiatives or modifications affecting operation or administration by the agencies of bill assistance or weatherization programs.

106. PSE shall not proceed with implementation of third party scheduling of HELP/weatherization appointments until the proposal has been discussed with The Energy Project and affected agencies jointly and reviewed by the Advisory Committee.

107. The Settling Parties agree to the establishment of an Advisory Committee for PSE bill assistance. The Advisory Committee shall be formed no later than January 1, 2018, and the first meeting of the Advisory Committee shall occur no later than March 1, 2018. The Advisory Committee shall include representatives from PSE, The Energy Project, Commission Staff, Public Counsel, and other interested stakeholders. The costs of the Advisory Committee will be recovered through general rates, similar to the manner in which Avista is authorized to recover such costs. The goals of the Advisory Committee are (i) to keep customers connected to their energy service; (ii) to provide assistance to more customers than are currently served; (iii) to lower the energy burden of PSE's HELP participants; and (iv) to collect data necessary to assess program effectiveness and inform ongoing policy discussions.

108. PSE shall provide up to $2 million through June 30, 2019, for the purpose of covering expenses related to the delivery of the Low-Income Weatherization Program to eligible PSE customers as a one-time contribution in addition to current funding. This will be recovered through Schedule 120. Eligible expenses include the installation of Department of Commerce Weatherization Manual approved cost effective energy efficiency measures, project coordination, health and safety measures, and repairs necessary for the installation of energy efficiency measures.

109. As part of the original decoupling mechanism, PSE agreed to increase its funding for low-income weatherization by $500,000 per year. The Settling Parties agree to PSE's proposal to continue this higher funding level for the proposed mechanism in this proceeding.

110. PSE shall continue annual $100,000 shareholder contributions to low-income weatherization, until the next general rate case, consistent with the commitment that PSE made

in the multi-year rate plan approved in Docket UE-121697. This term does not modify any other pre-existing obligation for shareholder funding.

111. The Settling Parties agree to PSE's proposal to modify Schedule 129 to remove Area Median Income from the HELP program Income Eligibility Criteria. On and after the effective date of the tariffs resulting from this proceeding, income eligibility will be based on a household income not exceeding 150 percent of the federal poverty level.

F. Prudence Issues

112. The Settling Parties agree to support a Commission determination in this proceeding that the following projects of PSE are prudent and PSE shall fully recover costs associated with the following projects:

(i) the Snoqualmie Falls hydroelectric redevelopment project;

(ii) the acquisition of the Buckley Natural Gas Distribution System;

(iii) the acquisition and development of the Glacier Battery Storage System;

(iv) the development and construction of the Ardmore Substation;

(v) the power purchase agreement with Public Utility District No. 1 Public Utility District No. 1 of Douglas County, Washington to purchase power from the Wells Hydroelectric Project;

(vi) the acquisition of transmission capacity from Bonneville Power Administration for the (a) the Goldendale Generation Facility (38 MW) and (b) the Mint Farm Generation Facility (15 MW); and

(vii) the renewal of agreements for transmission capacity from Bonneville Power Administration associated with (a) the Coal Transition Power Purchase Agreement (100 MW), (b) the Mint Farm Generation Facility (20 MW), and (c) purchases from Garrison, Montana (94 MW); and

(viii) the total amount of actual costs accumulated and deferred until September 30, 2016, associated with PSE's electric and natural gas Environmental Remediation program.

G. Decoupling

113. The Settling Parties agree to Commission Staff's proposal to set the total Allowed Revenue for fixed production costs recovery per decoupled group at the level the Commission authorizes in this general rate proceeding.

114. The Settling Parties agree that all other issues with respect to PSE's revenue decoupling mechanism are not affected by this Settlement and are subject to litigation before the Commission. This includes all other issues regarding the Earnings Sharing Mechanism not otherwise addressed in this Settlement.

H. ERF Issues

115. PSE may file one ERF within one year after the effective date of the tariffs resulting from this proceeding that is consistent with the process and procedures used by the Commission in Dockets UE-130137 & UG-130138 and the parameters identified in Exhibit I to this Settlement. The Settling Parties will support, or not oppose, a schedule for such ERF that would allow rates to take effect within 120 calendar days after filing. Any subsequent ERF or limited rate proceeding filed by PSE shall be consistent with Commission guidance provided by rule or policy statement in Docket A-130355.

I. Colstrip Plant and Transmission System Issues

1. Retirement Account Established Pursuant to Chapter 80.84 RCW

116. PSE shall place $95 million in hydro-related Treasury Grants into a retirement account established pursuant to RCW 80.04.350 to fund and recover prudently incurred decommissioning and remediation costs for Colstrip Units 1 and 2 consistent with Chapter 80.84 RCW.

2. Account Not Established Pursuant to Chapter 80.84 RCW

117. PSE shall place PTCs as they are monetized in a second, more flexible account not established pursuant to Chapter 80.84 RCW. PSE shall use the monetized PTCs in the second account in accordance with the following priority for use: (i) to fund community transition planning funds of $5 million, as identified in paragraph 118; (ii) to recover unrecovered plant balances for Colstrip Units 1 through 4; and (iii) to fund and recover prudently incurred decommissioning and remediation costs for Colstrip Units 1 through 4. The account shall be consistent with the discussion of the account set forth in the Prefiled Rebuttal Testimony of Ms. Katherine J. Barnard, Exh. KJB-17T.

3. Community Transition Planning Process & Funding

118. PSE shall engage in a process with stakeholders to develop a community transition plan, including a funding mechanism, to address the transitioning of PSE's interest in the community of Colstrip, Montana. PSE shall contribute the following amounts to the community transition plan: (i) $5 million of shareholder dollars and (ii) $5 million of monetized PTCs. PSE shall place the $5 million of shareholder dollars in an escrow account (the "Escrow Account") by the end of calendar year 2018. PSE shall place $5 million of monetized PTCs, when available, from the account established pursuant to paragraph 117 in the Escrow Account. All such funds shall remain in the Escrow Account until such time that there is a community transition plan, including a funding mechanism, in place.

4. Colstrip Reporting Requirements

119. Beginning in 2018, on or before December 1 of each year, PSE shall provide the Commission an annual report containing the following:

(i) the most recent estimate of the actual retirement date for Colstrip Units 1 and 2 and Colstrip Units 3 and/or 4;

(ii) In the event of an estimated retirement date earlier than July 1, 2022, for Colstrip Units 1 and 2, and upon the determination by PSE of an estimated retirement date for Colstrip Units 3 and/or 4, a discussion and evaluation of consequences to customers arising from those estimated retirement dates;

(iii) decommissioning and remediation expenditures associated with Colstrip units since the time of the last report and updated estimates of future costs;

(iv) an evaluation of the sufficiency of the retirement account established pursuant to Chapter 80.84 RCW to fund and recover decommissioning and remediation activities for Colstrip Units 1 and 2;

(v) an evaluation of the sufficiency of existing depreciation rates for Colstrip Units 3 and 4 to cover decommissioning and remediation costs for those units; and

(vi) for years in which PSE issues an Integrated Resource Plan, updated replacement power costs.

5. Colstrip Transmission System Operational Study

120. PSE is working with NorthWestern Energy and the other Colstrip Transmission System owners on the design and staffing of an operational study of transfer capability of the Colstrip Transmission System after Colstrip Units 1 and 2 retire. PSE agrees to work in good faith with the other Colstrip Transmission System owners to have this study completed by June 30, 2018. Upon completion of the study, study results will be submitted to the Commission and interested stakeholders, subject to the consent of the other Colstrip Transmission System owners and subject to disclosure restrictions, such as restrictions on disclosure of Critical Energy Infrastructure Information and non-public transmission information.

6. Colstrip Transmission System Workshop

121. The Settling Parties recommend that the Commission convene one or more workshops, to commence in the first quarter of 2018, to discuss the use of the Colstrip

Transmission System following closure of Colstrip Units 1 and 2, including use by new generation. Commission Staff, the Colstrip Transmission System owners, Path 8 operators, and interested stakeholders will be invited to attend the workshop(s) and to participate in the development of a "Scoping Document" that is intended to (i) identify any known policy or contractual barriers and the technical questions surrounding the use of the Colstrip Transmission System following closure of Colstrip Units 1 and 2, (ii) identify methods, forums, and possible timelines for addressing barriers and technical questions, and (iii) provide information regarding, and promote an understanding of, the applicable processes and procedures, studies, and timelines for addressing these questions, including but not limited to those specified in the Open Access Transmission Tariffs of the Colstrip Transmission System owners for requesting and procuring interconnection to and transmission on the Colstrip Transmission System. The Scoping Document should identify the necessary engineering studies, data, and costs associated with completing the studies, and any other barriers to completing the studies. It is anticipated that PSE will be the primary author of the Scoping Document with input from Commission Staff, the Colstrip Transmission System owners, Path 8 operators, and interested stakeholders. Compliance with the settlement terms does not necessarily include the completion of any additional transmission engineering studies themselves, though the Scoping Document may identify studies that can be completed in the near-term.

7. No Release

122. Nothing in this Settlement shall be construed to operate as a settlement, release or waiver of any and all of PSE's liabilities for decommissioning and remediation in the State of Montana under Montana or federal law regarding any or all of Colstrip Units 1 through 4.

Nothing in this Settlement shall be construed to operate as expanding or contracting the powers of the State of Montana with respect to any or all of Colstrip Units 1 through 4.

J. Water Heater Rental Program

123. PSE will participate in a collaborative with Commission Staff and other interested stakeholders to discuss the future of the water heater rental programs in PSE's natural gas Schedules 71, 72, and 74.

K. Electric Cost Recovery Mechanism

124. The Settling Parties agree that all issues with respect to PSE's proposed Electric Cost Recovery Mechanism are not affected by this Settlement and are subject to litigation before the Commission.

IV. GENERAL PROVISIONS

125. Entire Agreement. This Settlement is the product of negotiations and compromise amongst the Settling Parties and constitutes the entire agreement of the Settling Parties. Accordingly, the Settling Parties recommend that the Commission adopt and approve the Settlement in its entirety as a full resolution of contested issues in this docket. This Settlement will not be construed against any Settling Party on the basis that it was the drafter of any or all portions of this Settlement. This Settlement supersedes any and all prior oral and written understandings and agreements on such matters that previously existed or occurred in this proceeding, and no such prior understanding or agreement or related representations will be relied upon by the Settling Parties to interpret this Settlement or for any other reason.

126. Confidentiality of Negotiations. The Settling Parties agree that this Settlement represents a compromise in the Settling Parties' positions. As such, conduct, statements and documents disclosed during the negotiation of this Settlement are not admissible in this or any

other proceeding and will remain confidential. Notwithstanding the foregoing, the Settlement itself and its terms do not fall within the scope of this confidentiality provision, and each Settling Party is free to publicly disclose the basis for its own support of the Settlement.

127. Precedential Effect of Settlement. The Settling Parties enter into this Settlement to avoid further expense, uncertainty, inconvenience and delay. The Settling Parties agree that this Settlement Agreement does not serve to bind the Commission when it considers any other matter not specifically resolved by this Settlement in future proceedings. Nothing in this Settlement compels any Settling Party to affirmatively intervene or participate in a future proceeding.

128. Positions Not Conceded. In reaching this Settlement, the Settling Parties agree that no Settling Party concedes any particular argument advanced by that Settling Party or accedes to any particular argument made by any other Settling Party. Nothing in this Settlement (or any testimony, presentation or briefing supporting this Settlement) shall be asserted or deemed to mean that a Settling Party agreed with or adopted another Settling Party's legal or factual assertions in this proceeding. The limitations in this paragraph 128 will not apply to any proceeding to enforce the terms of this Settlement or any Commission order adopting this Settlement in full.

129. Manner of Execution. This Settlement is executed when all Settling Parties sign the Settlement. A designated and authorized representative may sign the Settlement on a Settling Party's behalf. The Settling Parties may execute this Settlement in counterparts. If the Settlement is executed in counterparts, all counterparts shall constitute one agreement. A Settlement signed in counterpart and sent by facsimile or emailed as a pdf is as effective as an original document. A faxed or emailed signature page containing the signature of a Settling Party is acceptable as an original signature page signed by that Settling Party. Each Settling Party shall indicate the date of

its signature on the signature page. The date of execution of the Settlement will be the latest date indicated on the signature page(s).

130. Approval Process and Support of Settlement. Each Settling Party agrees to support in this proceeding the terms and conditions of this Settlement as a full and final resolution of all contested issues between them in the above-captioned docket. Each Settling Party agrees to support or not to oppose the Settlement during the course of whatever proceedings and procedures the Commission determines are appropriate for approval of the Settlement.

131. Commission Approval with Conditions. In the event the Commission approves this Settlement, but with conditions not proposed in this Settlement, the provisions of WAC 480-07-550(2)(b) will apply. The Settling Parties will have ten (10) business days to seek reconsideration and/or file a letter with the Commission accepting or rejecting each such condition. If, in such a timely filed letter, a Settling Party rejects a condition, this Settlement is deemed rejected and void and the Settling Parties will jointly and promptly request the Commission convene a prehearing conference to address procedural matters, including a procedural schedule for resolution of the case at the earliest possible date.

132. Commission Rejection. In the event the Commission rejects this Settlement, the provisions of WAC 480-07-550(2)(a) will apply. In that event, the Settling Parties agree to jointly and promptly request the Commission convene a prehearing conference to address procedural matters, including a procedural schedule for resolution of the case at the earliest possible date.

[Remainder of Page Intentionally Left Blank. Signature Page to Follow]

Dated this 15th day of September, 2017.

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Attorney for Sierra Club

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Dated this 15th day of September, 2017.

PUGET SOUND ENERGY

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Exhibit A to the Multiparty Settlement Stipulation and Agreement

Exhibit A to the Multiparty Settlement Stipulation and Agreement
Dockets UE-170033 and UG-170034
Electric Restating and Pro Forma Adjusments

Adjustment (a)	NOI (b)	Rate Base (c)	Revenue Requirement (d) (Note 1)
Actual Results of Operations	$ 401,002,972	$ 5,153,204,462	$ (15,119,001)
Adjustment 13.01-Revenues & Expenses	(29,139,114)	-	47,070,619
Adjustment 13.02-Temperature Normalization	17,527,344	-	(28,313,247)
Adjustment 13.03-Pass-Through Revs. & Exps.	(1,000,540)	-	1,616,249
Adjustment 13.04-Federal Income Tax	(27,023,239)	-	43,652,686
Adjustment 13.05-Tax Benefit of Proforma Interest	54,067,781	-	(87,339,785)
Adjustment 13.06-Depreciation Study	(34,311,788)	(17,155,894)	53,320,227
Adjustment 13.06A-Reg. Asset Colstrip	-	-	-
Adjustment 13.07-Normalize Injuries & Damages	69,387	-	(112,087)
Adjustment 13.08-Bad Debts	681,065	-	(1,100,176)
Adjustment 13.09-Incentive Pay	(109,903)	-	177,535
Adjustment 13.10-D&O Insurance	16,141	-	(26,074)
Adjustment 13.11-Interest on Customer Deposits	(176,606)	-	285,284
Adjustment 13.12-Rate Case Expenses	(264,905)	-	427,920
Adjustment 13.13-Deferred G/L on Property Sales	171,200	-	(276,552)
Adjustment 13.14-Property & Liability Ins	66,147	-	(106,852)
Adjustment 13.15-Pension Plan	(1,184,945)	-	1,914,132
Adjustment 13.16-Wage Increase	(1,357,716)	-	2,193,221
Adjustment 13.17-Investment Plan	(96,705)	-	156,214
Adjustment 13.18-Employee Insurance	(121,751)	-	196,674
Adjustment 13.19-Environmental Remediation	(925,460)	-	1,494,966
Adjustment 13.20-Payment Processing Costs	(2,010,221)	-	3,247,263
Adjustment 13.21-South King Service Center	434,046	15,915,060	1,252,721
Adjustment 13.22-Excise Tax and WUTC Filing Fee	10,262	-	(16,577)
Adjustment 13.23-ISWC and RB Adjustment	-	19,006,090	2,333,350
Adjustment 13.24-Legal Cost Adjustment	-	-	-
Adjustment 13.25-Black Box Adjustment	619,051	-	(1,000,000)
Adjustment 14.01-Power Costs	1,185,175	-	(1,914,503)
Adjustment 14.02-Montana Electric Energy Tax	148,016	-	(239,101)
Adjustment 14.03-Wild Horse Solar	137,890	(1,969,341)	(464,518)
Adjustment 14.04-ASC 815 (Prev. SFAS 133)	(41,672,584)	-	67,316,883
Adjustment 14.05-Storm Damage	(6,137,438)	-	9,914,269
Adjustment 14.06-Reg Assets & Liabilities	1,736,212	(44,085,326)	(8,216,927)
Adjustment 14.07-Glacier Battery Storage	(145,490)	2,842,787	584,026
Adjustment 14.08-Energy Imbalance Market	-	-	-
Adjustment 14.09-Goldendale Capacity Upgrade	2,156	18,140,954	2,223,656
Adjustment 14.10-Mint Farm Capacity Upgrade	-	19,004,590	2,333,166
Adjustment 14.11-White River	(3,288,310)	(4,108,724)	4,807,435
Adjustment 14.12-Reclass of Hydro Treasury Grants	(2,131,857)	5,739,615	4,148,394
Adjustment 14.13-Production Adjustment	32,769	-	(52,934)
Adjusted Results of Operations	326,809,044	5,166,534,272	106,368,556
Changes to Other Price Schedules			(86,208,222)
Overall Electric Revenue Requirement Deficiency			20,160,334

(Note 1) (d) = column (c) x 7.60% rate of return per paragraph 11 of the Settlement less column (b) and the result is divided by the electric conversion factor of .619051 from Exh. MCC-3r at 3.

Exhibit A to the Multiparty Settlement Stipulation and Agreement
Dockets UE-170033 and UG-170034
Gas Restating and Pro Forma Adjusments

Adjustment (a)	NOI (b)	Rate Base (c)	Revenue Requirement (d) (Note 1)
Actual Results of Operations	$ 119,145,769	$ 1,727,319,760	$ 19,551,185
Adjustment 11.01-Revenues & Expenses	(32,674,131)	-	52,661,989
Adjustment 11.02-Temperature Normalization	16,046,445	-	(25,862,592)
Adjustment 11.03-Pass-Through Revs. & Exps.	736,148	-	(1,186,474)
Adjustment 11.04-Federal Income Tax	700,822	-	(1,129,538)
Adjustment 11.05-Tax Benefit of Proforma Interest	18,475,298	-	(29,777,255)
Adjustment 11.06-Depreciation Study	13,174,098	6,587,049	(20,426,274)
Adjustment 11.07-Normalize Injuries & Damages	(57,738)	-	93,058
Adjustment 11.08-Bad Debts	35,240	-	(56,797)
Adjustment 11.09-Incentive Pay	104,023	-	(167,657)
Adjustment 11.10-D&O Insurance	11,636	-	(18,754)
Adjustment 11.11-Interest on Customer Deposits	(50,137)	-	80,807
Adjustment 11.12-Rate Case Expenses	(280,617)	-	452,280
Adjustment 11.13-Deferred G/L on Property Sales	(105,090)	-	169,377
Adjustment 11.14-Property & Liability Ins	45,174	-	(72,809)
Adjustment 11.15-Pension Plan	(572,091)	-	922,058
Adjustment 11.16-Wage Increase	(907,409)	-	1,462,502
Adjustment 11.17-Investment Plan	(46,689)	-	75,250
Adjustment 11.18-Employee Insurance	(58,781)	-	94,740
Adjustment 11.19-Environmental Remediation	(5,592,128)	-	9,013,019
Adjustment 11.20-Payment Processing Costs	(1,449,117)	-	2,335,590
Adjustment 11.21-South King Service Center	212,048	7,775,116	610,622
Adjustment 11.22-Excise Tax and WUTC Filing Fee	33,509	-	(54,008)
Adjustment 11.23-ISWC and RB Adjustment		4,743,346	581,021
Adjustment 11.24-Legal Cost Adjustment	-	-	-
Adjustment 11.25-Black Box Adjustment	930,675	-	(1,500,000)
Adjustment 07.01-Gas Cost Recovery Mechanism	(4,003,724)	19,011,708	8,781,713
Adjusted Results of Operations	123,853,234	1,765,436,979	16,633,051
Changes to Other Price Schedules			(52,098,690)
Overall Natural Gas Revenue Requirement Surplus			(35,465,639)

(Note 1) Calculated as column (c) x 7.60% rate of return per paragraph 11 of the Settlement less column (b) and the result is divided by the natural gas conversion factor of .620450 from Exh. MCC-8r at 3.

Exhibit B to the Multiparty Settlement Stipulation and Agreement

Exhibit B to the Multiparty Settlement Stipulation and Agreement

Docket Nos. UE-170033 and UG-170034

Electric Depreciation Study Adjustment

LINE NO.	DESCRIPTION	TEST YEAR	RESTATED	ADJUSTMENT
1	403 ELEC. DEPRECIATION EXPENSE	$249,419,038	$ 306,097,054	$ 56,678,016
2	403 ELEC. PORTION OF COMMON	15,207,048	13,232,379	(1,974,669)
3	403 DEPR. EXP. ON ASSETS NOT INCLUDED IN STUDY	55,938	55,938	-
4	404 DEPR. EXP. ON ASSETS NOT INCLUDED IN STUDY	29,770,695	29,770,695	-
5	SUBTOTAL DEPRECIATION EXPENSE 403	294,452,719	349,156,066	54,703,348
6				
7	403.1 DEPR. EXP- FAS 143 (RECOVERED IN RATES)	1,352,125	1,729,703	377,578
8	403.1 DEPR. EXP - FAS 143 (NOT RECOVERED IN RATES)	1,476,017	-	(1,476,017)
9	SUBTOTAL DEPRECIATION EXPENSE 403.1	2,828,141	1,729,703	(1,098,438)
10				
11	TOTAL DEPRECIATION EXPENSE	297,280,860	350,885,769	53,604,909
12				
13	AMORTIZATION EXPENSE			
14	411.10 ACCRETION EXP. - ASC 410 (RECOVERED IN RATES)	1,424,661	2,062,091	637,430
15	411.10 ACCRETION EXP. - ASC 410 (NOT RECOVERED IN RATES)	1,148,003	-	(1,148,003)
16	SUBTOTAL ACCRETION EXPENSE 411.10	2,572,664	2,062,091	(510,573)
17				
18	DEPRECIATION EXPENSE 403 ASSOCIATED WITH FLEET	846,819	539,849	(306,970)
19				
20				
21	INCREASE (DECREASE) EXPENSE			52,787,366
22	INCREASE (DECREASE) FIT			(18,475,578)
23	INCREASE (DECREASE) NOI			$ (34,311,788)
24				
25				
26	**ADJUSTMENT TO RATE BASE**			
27	ADJUSTMENT TO ACCUM. DEPREC. AT 50% DEPREC. EXP. LINE	50%		$ (26,393,683)
28	DFIT			9,237,789
29				
30	TOTAL ADJUSTMENT TO RATEBASE			$ (17,155,894)

Exhibit B to the Multiparty Settlement Stipulation and Agreement

Docket Nos. UE-170033 and UG-170034

Approved Electric Plant Depreciation Rates

Table 1. Summary of Estimated Survivor Curves, Net Salvage Percent, Original Cost, Book Depreciation Reserve and Calculated Annual Depreciation Rates as of September 30, 2016

FERC	ACCOUNT	PROBABLE RETIREMENT DATE	SURVIVOR CURVE	NET SALVAGE PERCENT	ORIGINAL COST AS OF SEPTEMBER 30, 2016	BOOK DEPRECIATION RESERVE	FUTURE ACCRUALS	CALCULATED ANNUAL ACCRUAL AMOUNT	CALCULATED ANNUAL ACCRUAL RATE	COMPOSITE REMAINING LIFE
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)=(8)/(5) (except Colstrip Units 1&2) (NOTE 1)	(10)=(7)/(8)
	ELECTRIC PLANT									
	STEAM PRODUCTION PLANT									
311.00	STRUCTURES AND IMPROVEMENTS									
	COLSTRIP 1	(NOTE 1)	(NOTE 1)	* (NOTE 1)	9,209,468	(NOTE 1)	(NOTE 1)	447,725	4.86	(NOTE 1)
	COLSTRIP 2	(NOTE 1)	(NOTE 1)	* (NOTE 1)	4,336,957	(NOTE 1)	(NOTE 1)	321,879	7.42	(NOTE 1)
	COLSTRIP 3 (NOTE 2)	12-2027	90-R2	* (10)	29,664,979	21,454,595	11,176,882	1,012,631	3.41	11.0
	COLSTRIP 4 (NOTE 2)	12-2027	90-R2	* (10)	27,862,835	19,334,081	11,315,037	1,024,406	3.68	11.0
	COLSTRIP 1-2	(NOTE 1)	(NOTE 1)	* (NOTE 1)	30,934,200	(NOTE 1)	(NOTE 1)	808,539	2.61	(NOTE 1)
	COLSTRIP 3-4 (NOTE 2)	12-2027	90-R2	* (10)	70,065,641	52,568,884	24,503,321	2,222,796	3.17	11.0
	FREDERICKSON 1/EPCOR	06-2042	90-R2	* (5)	403,636	8,557	415,261	16,597	4.11	25.0
	GOLDENDALE	06-2044	90-R2	* (5)	2,131,452	1,475,544	762,481	28,273	1.33	27.0
	MINT FARM	06-2047	90-R2	* (5)	458,042	117,386	363,559	12,208	2.67	29.8
	SUMAS	06-2033	90-R2	* (5)	1,492,712	1,197,365	369,982	22,408	1.50	16.5
	FERNDALE	06-2034	90-R2	* (5)	571,513	367,246	232,843	13,296	2.33	17.5
	TOTAL STRUCTURES AND IMPROVEMENTS				177,131,434	96,523,657	49,139,366	5,930,758	3.35	8.3
312.00	BOILER PLANT EQUIPMENT									
	COLSTRIP 1	(NOTE 1)	(NOTE 1)	* (NOTE 1)	88,145,748	(NOTE 1)	(NOTE 1)	5,451,528	6.18	(NOTE 1)
	COLSTRIP 2	(NOTE 1)	(NOTE 1)	* (NOTE 1)	88,368,523	(NOTE 1)	(NOTE 1)	5,914,163	6.69	(NOTE 1)
	COLSTRIP 3 (NOTE 2)	12-2027	75-S0	* (10)	137,645,882	88,664,395	62,746,075	5,786,628	4.20	10.8
	COLSTRIP 4 (NOTE 2)	12-2027	75-S0	* (10)	126,930,413	74,762,985	64,860,469	5,968,231	4.70	10.9
	COLSTRIP 1-2	(NOTE 1)	(NOTE 1)	* (NOTE 1)	6,043,572	(NOTE 1)	(NOTE 1)	151,538	2.51	(NOTE 1)
	COLSTRIP 3-4 (NOTE 2)	12-2027	75-S0	* (10)	15,254,042	10,094,597	6,684,848	622,947	4.08	10.7
	ENCOGEN	06-2033	75-S0	* (5)	42,923,481	34,057,590	11,012,065	689,589	1.61	16.0
	FREDERICKSON 1/EPCOR	06-2042	75-S0	* (5)	18,138,531	7,308,605	11,736,853	489,745	2.70	24.0
	GOLDENDALE	06-2044	75-S0	* (5)	86,173,650	66,841,917	23,640,415	914,220	1.06	25.9
	MINT FARM	06-2047	75-S0	* (5)	26,297,847	3,059,104	24,553,635	860,987	3.27	28.5
	SUMAS	06-2033	75-S0	* (5)	15,704,259	13,938,347	2,551,125	157,672	1.00	16.2
	FERNDALE	06-2034	75-S0	* (5)	44,686,468	30,590,589	16,330,202	947,227	2.12	17.2
	TOTAL BOILER PLANT EQUIPMENT				696,312,415	329,318,128	224,115,687	27,954,475	4.01	8.0
314.00	TURBOGENERATOR UNITS									
	COLSTRIP 1	(NOTE 1)	(NOTE 1)	* (NOTE 1)	28,781,740	(NOTE 1)	(NOTE 1)	1,952,444	6.78	(NOTE 1)
	COLSTRIP 2	(NOTE 1)	(NOTE 1)	* (NOTE 1)	34,145,119	(NOTE 1)	(NOTE 1)	2,277,281	6.67	(NOTE 1)
	COLSTRIP 3 (NOTE 2)	12-2027	45-R1.5	* (9)	42,228,337	15,440,101	30,588,786	2,943,524	6.97	10.4
	COLSTRIP 4 (NOTE 2)	12-2027	45-R1.5	* (9)	39,133,170	15,579,409	27,075,747	2,582,499	6.60	10.5
	COLSTRIP 1-2	(NOTE 1)	(NOTE 1)	* (NOTE 1)	3,813,726	(NOTE 1)	(NOTE 1)	105,285	2.76	(NOTE 1)
	ENCOGEN	06-2033	45-R1.5	* (5)	20,710,885	16,987,716	4,758,714	309,829	1.50	15.4
	FREDERICKSON 1/EPCOR	06-2042	45-R1.5	* (5)	15,800,824	6,391,663	10,199,202	452,092	2.86	22.6

Exhibit B to the Multiparty Settlement Stipulation and Agreement

Docket Nos. UE-170033 and UG-170034

Approved Electric Plant Depreciation Rates

Table 1. Summary of Estimated Survivor Curves, Net Salvage Percent, Original Cost, Book Depreciation Reserve and Calculated Annual Depreciation Rates as of September 30, 2016

FERC	ACCOUNT	PROBABLE RETIREMENT DATE	SURVIVOR CURVE		NET SALVAGE PERCENT	ORIGINAL COST AS OF SEPTEMBER 30, 2016	BOOK DEPRECIATION RESERVE	FUTURE ACCRUALS	CALCULATED ANNUAL ACCRUAL AMOUNT	CALCULATED ANNUAL ACCRUAL RATE	COMPOSITE REMAINING LIFE
	(1)	(2)	(3)		(4)	(5)	(6)	(7)	(8)	(9)=(8)/(5)	(10)=(7)/(8)
	GOLDENDALE	06-2044	45-R1.5	*	(5)	89,524,456	69,143,032	24,857,647	1,016,648	1.14	24.5
	MINT FARM	06-2047	45-R1.5	*	(5)	24,647,470	6,463,275	19,416,568	728,552	2.96	26.7
	SUMAS	06-2033	45-R1.5	*	(5)	22,032,535	17,817,477	5,316,684	336,528	1.53	15.8
	FERNDALE	06-2034	45-R1.5	*	(5)	18,176,145	11,698,599	7,386,353	439,610	2.42	16.8
	TOTAL TURBOGENERATOR UNITS					338,994,406	159,521,273	129,599,701	13,144,292	3.88	9.9
315.00	ACCESSORY ELECTRIC EQUIPMENT										
	COLSTRIP 1	(NOTE 1)	(NOTE 1)	*	(NOTE 1)	7,465,363	(NOTE 1)	(NOTE 1)	399,892	5.36	(NOTE 1)
	COLSTRIP 2	(NOTE 1)	(NOTE 1)	*	(NOTE 1)	4,167,725	(NOTE 1)	(NOTE 1)	272,129	6.53	(NOTE 1)
	COLSTRIP 3 (NOTE 2)	12-2027	60-S2	*	(9)	6,769,582	4,484,210	2,894,634	271,489	4.01	10.7
	COLSTRIP 4 (NOTE 2)	12-2027	60-S2	*	(9)	6,474,414	3,767,317	3,289,794	304,686	4.71	10.8
	COLSTRIP 1-2	(NOTE 1)	(NOTE 1)	*	(NOTE 1)	2,272,861	(NOTE 1)	(NOTE 1)	53,628	2.36	(NOTE 1)
	COLSTRIP 3-4 (NOTE 2)	12-2027	60-S2	*	(9)	7,639,006	5,452,901	2,873,616	271,079	3.55	10.6
	ENCOGEN	06-2033	60-S2	*	0	1,678,559	1,328,206	350,353	21,481	1.28	16.3
	FREDERICKSON 1/EPCOR	06-2042	60-S2	*	0	962,487	358,861	603,625	24,389	2.53	24.7
	GOLDENDALE	06-2044	60-S2	*	0	7,300,879	5,714,400	1,586,479	59,087	0.81	26.8
	MINT FARM	06-2047	60-S2	*	0	2,199,936	586,806	1,613,130	54,516	2.48	29.6
	SUMAS	06-2033	60-S2	*	0	670,282	579,011	91,271	5,491	0.82	16.6
	FERNDALE	06-2034	60-S2	*	0	1,279,531	862,622	416,909	23,581	1.84	17.7
	TOTAL ACCESSORY ELECTRIC EQUIPMENT					48,880,623	23,134,333	13,719,811	1,761,448	3.60	7.8
316.00	MISCELLANEOUS POWER PLANT EQUIPMENT										
	COLSTRIP 1	(NOTE 1)	(NOTE 1)	*	(NOTE 1)	946,612	(NOTE 1)	(NOTE 1)	63,866	6.75	(NOTE 1)
	COLSTRIP 2	(NOTE 1)	(NOTE 1)	*	(NOTE 1)	1,075,704	(NOTE 1)	(NOTE 1)	67,982	6.32	(NOTE 1)
	COLSTRIP 3 (NOTE 2)	12-2027	50-R1.5	*	(9)	1,043,991	378,123	759,827	70,639	6.77	10.8
	COLSTRIP 4 (NOTE 2)	12-2027	50-R1.5	*	(9)	1,165,681	420,604	849,988	79,228	6.80	10.7
	COLSTRIP 1-2	(NOTE 1)	(NOTE 1)	*	(NOTE 1)	6,205,597	(NOTE 1)	(NOTE 1)	202,687	3.27	(NOTE 1)
	COLSTRIP 1-4 (NOTE 2)	12-2027	50-R1.5	*	(8)	251,534	195,027	76,629	7,436	2.96	10.3
	COLSTRIP 3-4 (NOTE 2)	12-2027	50-R1.5	*	(9)	4,444,375	2,910,938	1,933,432	185,051	4.16	10.4
	FREDERICKSON 1/EPCOR	06-2042	50-R1.5	*	0	336,378	138,260	198,118	8,565	2.55	23.1
	GOLDENDALE	06-2044	50-R1.5	*	0	6,163	4,824	1,339	54	0.88	24.8
	MINT FARM	06-2047	50-R1.5	*	0	152,757	38,799	113,958	4,168	2.73	27.3
	SUMAS	06-2033	50-R1.5	*	0	123,691	109,782	13,909	874	0.71	15.9
	FERNDALE	06-2034	50-R1.5	*	0	62,866	43,036	19,830	1,171	1.86	16.9
	TOTAL MISCELLANEOUS POWER PLANT EQUIPMENT					15,815,349	4,239,392	3,967,030	691,721	4.37	5.7
	TOTAL STEAM PRODUCTION PLANT					**1,277,134,228**	**612,736,784**	**420,541,595**	**49,482,694**	**3.87**	

(NOTE 1) Depreciation Rates for Colstrip Units 1 and 2 were determined separately - see pages 12 and 13 of this Exhibit B for the information used to calculated the depreciation rates for Colstrip Units 1 and 2.

(NOTE 2) Please see paragraph 27 of Settlement Stipulation and Agreement with resepect to Colstrip Units 3 and 4.

Approved Electric Plant Depreciation Rates

Table 1. Summary of Estimated Survivor Curves, Net Salvage Percent, Original Cost, Book Depreciation Reserve and Calculated Annual Depreciation Rates as of September 30, 2016

FERC	ACCOUNT	PROBABLE RETIREMENT DATE	SURVIVOR CURVE		NET SALVAGE PERCENT	ORIGINAL COST AS OF SEPTEMBER 30, 2016	BOOK DEPRECIATION RESERVE	FUTURE ACCRUALS	CALCULATED ANNUAL ACCRUAL AMOUNT	CALCULATED ANNUAL ACCRUAL RATE	COMPOSITE REMAINING LIFE
	(1)	(2)	(3)		(4)	(5)	(6)	(7)	(8)	(9)=(8)/(5)	(10)=(7)/(8)
	HYDROELECTRIC PRODUCTION PLANT										
330.10	EASEMENTS	06-2049	SQUARE	*	0	32,899	11,390	21,509	657	2.00	32.7
331.00	STRUCTURES AND IMPROVEMENTS										
	LOWER BAKER	10-2058	75-S1	*	(5)	35,273,454	6,306,966	30,730,161	776,755	2.20	39.6
	UPPER BAKER	10-2058	75-S1	*	(7)	15,612,654	6,565,230	10,140,309	260,751	1.67	38.9
	SNOQUALMIE #1	06-2044	75-S1	*	(2)	58,654,809	5,540,003	54,287,902	2,009,010	3.43	27.0
	SNOQUALMIE #2	06-2044	75-S1	*	(2)	54,612,246	5,903,872	49,800,619	1,834,277	3.36	27.1
	TOTAL STRUCTURES AND IMPROVEMENTS					164,153,163	24,316,071	144,958,991	4,880,793	2.97	29.7
332.00	RESERVOIRS, DAMS AND WATERWAYS										
	LOWER BAKER	10-2058	90-R1.5	*	(9)	115,624,470	22,402,337	103,628,335	2,636,328	2.28	39.3
	UPPER BAKER	10-2058	90-R1.5	*	(12)	119,603,565	59,809,738	74,146,255	1,900,806	1.59	39.0
	SNOQUALMIE #1	06-2044	90-R1.5	*	(4)	53,492,873	4,795,759	50,836,829	1,899,379	3.55	26.8
	SNOQUALMIE #2	06-2044	90-R1.5	*	(4)	60,540,017	4,528,235	58,433,383	2,184,265	3.61	26.8
	TOTAL RESERVOIRS, DAMS AND WATERWAYS					349,260,925	91,536,069	287,044,802	8,620,778	2.47	33.3
333.00	WATER WHEELS, TURBINES AND GENERATORS										
	LOWER BAKER	10-2058	75-S1	*	(6)	41,634,915	9,000,675	35,132,334	893,215	2.15	39.3
	UPPER BAKER	10-2058	75-S1	*	(9)	13,128,271	9,227,178	5,082,637	126,284	0.96	40.2
	SNOQUALMIE #1	06-2044	75-S1	*	(2)	36,614,585	3,022,251	34,324,626	1,266,049	3.46	27.1
	SNOQUALMIE #2	06-2044	75-S1	*	(2)	35,031,624	2,768,921	32,963,335	1,222,346	3.49	27.0
	TOTAL WATER WHEELS, TURBINES AND GENERATORS					126,409,394	24,019,025	107,502,932	3,507,894	1.82	26.2
334.00	ACCESSORY ELECTRIC EQUIPMENT										
	LOWER BAKER	10-2058	60-R2.5	*	(3)	15,578,198	2,648,683	13,396,861	343,909	2.21	39.0
	UPPER BAKER	10-2058	60-R2.5	*	(4)	2,738,078	1,380,698	1,466,903	38,385	1.40	38.2
	SNOQUALMIE #1	06-2044	60-R2.5	*	(1)	16,156,295	1,231,153	15,086,705	561,261	3.47	26.9
	SNOQUALMIE #2	06-2044	60-R2.5	*	(1)	11,055,386	725,092	10,440,848	388,424	3.51	26.9
	TOTAL ACCESSORY ELECTRIC EQUIPMENT					45,527,958	5,985,626	40,391,317	1,331,979	2.93	30.3
335.00	MISCELLANEOUS POWER PLANT EQUIPMENT										
	LOWER BAKER	10-2058	45-S1	*	(4)	8,012,780	1,065,749	7,267,543	216,627	2.70	33.5
	UPPER BAKER	10-2058	45-S1	*	(4)	1,115,022	447,518	712,105	22,020	1.97	32.3
	SNOQUALMIE #1	06-2044	45-S1	*	(1)	1,548,649	129,676	1,434,459	56,004	3.62	25.6
	SNOQUALMIE #2	06-2044	45-S1	*	(2)	1,592,311	173,199	1,450,958	56,628	3.56	25.6
	TOTAL MISCELLANEOUS POWER PLANT EQUIPMENT					12,268,762	1,816,142	10,865,065	351,279	2.86	30.9

Approved Electric Plant Depreciation Rates

Table 1. Summary of Estimated Survivor Curves, Net Salvage Percent, Original Cost, Book Depreciation Reserve and Calculated Annual Depreciation Rates as of September 30, 2016

FERC	ACCOUNT	PROBABLE RETIREMENT DATE	SURVIVOR CURVE		NET SALVAGE PERCENT	ORIGINAL COST AS OF SEPTEMBER 30, 2016	BOOK DEPRECIATION RESERVE	FUTURE ACCRUALS	CALCULATED ANNUAL ACCRUAL AMOUNT	CALCULATED ANNUAL ACCRUAL RATE	COMPOSITE REMAINING LIFE
	(1)	(2)	(3)		(4)	(5)	(6)	(7)	(8)	(9)=(8)/(5)	(10)=(7)/(8)
335.10	MISCELLANEOUS TOOLS										
	LOWER BAKER	10-2058	18-S4	*	0	846,483	637,395	209,088	15,022	1.77	13.9
	UPPER BAKER	10-2058	18-S4	*	0	597,433	140,377	457,056	61,911	10.36	7.4
	SNOQUALMIE #1	06-2044	18-S4	*	0	674,572	542,235	132,337	8,883	1.32	14.9
	SNOQUALMIE #2	06-2044	18-S4	*	0	80,300	77,265	3,035	206	0.26	14.7
	TOTAL MISCELLANEOUS TOOLS					2,198,788	1,397,272	801,516	86,022	3.91	9.3
336.00	ROADS, RAILROADS AND BRIDGES										
	LOWER BAKER	10-2058	75-S0.5	*	(1)	1,588,316	188,571	1,415,627	36,505	2.30	38.8
	UPPER BAKER	10-2058	75-S0.5	*	(2)	2,648,182	245,575	2,455,570	66,943	2.53	36.7
	SNOQUALMIE #1	06-2044	75-S0.5	*	0	637,501	60,852	576,649	21,557	3.38	26.7
	SNOQUALMIE #2	06-2044	75-S0.5	*	0	157,935	15,050	142,885	5,341	3.38	26.8
	TOTAL ROADS, RAILROADS AND BRIDGES					5,031,933	510,048	4,590,731	130,346	2.59	35.2
	TOTAL HYDROELECTRIC PRODUCTION PLANT					**704,883,823**	**149,591,644**	**596,176,863**	**18,909,748**	**2.68**	
	OTHER PRODUCTION PLANT										
340.10	EASEMENTS	06-2030	SQUARE	*	(5)	221,929	197,425	35,601	2,589	1.17	13.8
341.00	STRUCTURES AND IMPROVEMENTS										
	ENCOGEN	06-2033	55-R4	*	(5)	9,238,362	5,850,367	3,849,913	231,822	2.51	16.6
	FREDERICKSON 1/EPCOR	06-2042	55-R4	*	(5)	5,774,387	2,475,066	3,588,040	142,439	2.47	25.2
	GOLDENDALE	06-2044	55-R4	*	(5)	34,450,810	26,661,589	9,511,761	348,886	1.01	27.3
	MINT FARM	06-2047	55-R4	*	(5)	11,003,157	2,980,386	8,572,929	284,891	2.59	30.1
	SUMAS	06-2033	55-R4	*	(5)	2,897,942	2,321,057	721,782	43,243	1.49	16.7
	CRYSTAL MOUNTAIN	06-2028	55-R4	*	(5)	811,210	372,743	479,027	40,935	5.05	11.7
	FREDONIA	06-2030	55-R4	*	(5)	5,035,527	4,058,711	1,228,592	90,676	1.80	13.5
	FREDERICKSON	06-2030	55-R4	*	(5)	2,735,279	2,532,962	339,082	24,785	0.91	13.7
	WHITEHORN 2-3	06-2038	55-R4	*	(5)	1,010,183	442,590	618,102	28,546	2.83	21.7
	FERNDALE	06-2034	55-R4	*	(5)	5,927,075	3,829,889	2,393,540	135,152	2.28	17.7
	TOTAL STRUCTURES AND IMPROVEMENTS					78,883,932	51,525,360	31,302,768	1,371,375	1.74	22.8
341.01	STRUCTURES AND IMPROVEMENTS - WIND										
	LOWER SNAKE RIVER	06-2037	55-R4	*	(5)	31,416,966	4,583,746	28,404,068	1,373,504	4.37	20.7
	HOPKINS RIDGE	06-2030	55-R4	*	(5)	3,413,472	368,034	3,216,112	234,724	6.88	13.7
	WILD HORSE	06-2031	55-R4	*	(5)	15,120,072	3,203,468	12,672,608	862,193	5.70	14.7
	TOTAL STRUCTURES AND IMPROVEMENTS - WIND					49,950,510	8,155,248	44,292,788	2,470,421	4.95	17.9
342.00	FUEL HOLDERS, PRODUCERS AND ACCESSORIES										

Exhibit B to the Multiparty Settlement Stipulation and Agreement

Docket Nos. UE-170033 and UG-170034

Approved Electric Plant Depreciation Rates

Table 1. Summary of Estimated Survivor Curves, Net Salvage Percent, Original Cost, Book Depreciation Reserve and Calculated Annual Depreciation Rates as of September 30, 2016

FERC	ACCOUNT	PROBABLE RETIREMENT DATE	SURVIVOR CURVE		NET SALVAGE PERCENT	ORIGINAL COST AS OF SEPTEMBER 30, 2016	BOOK DEPRECIATION RESERVE	FUTURE ACCRUALS	CALCULATED ANNUAL ACCRUAL AMOUNT	CALCULATED ANNUAL ACCRUAL RATE	COMPOSITE REMAINING LIFE
	(1)	(2)	(3)		(4)	(5)	(6)	(7)	(8)	(9)=(8)/(5)	(10)=(7)/(8)
	ENCOGEN	06-2033	45-R3	*	(5)	8,121,641	6,540,475	1,987,248	125,475	1.54	15.8
	FREDERICKSON 1/EPCOR	06-2042	45-R3	*	(5)	1,804,663	697,152	1,197,744	50,752	2.81	23.6
	GOLDENDALE	06-2044	45-R3	*	(5)	1,887,875	1,477,641	504,628	19,635	1.04	25.7
	MINT FARM	06-2047	45-R3	*	(5)	1,457,862	419,775	1,110,980	39,466	2.71	28.2
	SUMAS	06-2033	45-R3	*	(5)	3,889,943	3,452,527	631,913	38,673	0.99	16.3
	CRYSTAL MOUNTAIN	06-2028	45-R3	*	(5)	476,309	67,263	432,862	37,348	7.84	11.6
	FREDONIA	06-2030	45-R3	*	(5)	3,739,992	2,415,322	1,511,669	122,288	3.27	12.4
	FREDERICKSON	06-2030	45-R3	*	(5)	3,702,107	3,642,779	244,434	20,693	0.56	11.8
	WHITEHORN 2-3	06-2038	45-R3	*	(5)	134,195	138,223	2,681	134	0.10	20.0
	FERNDALE	06-2034	45-R3	*	(5)	418,443	286,449	152,916	8,763	2.09	17.5
	TOTAL FUEL HOLDERS, PRODUCERS AND ACCESSORIES					25,633,031	19,137,607	7,777,075	463,227	1.81	16.8
344.00	GENERATORS										
	CRYSTAL MOUNTAIN	06-2028	60-R3	*	(5)	575,843	405,829	198,806	17,279	3.00	11.5
	FREDONIA	06-2030	60-R3	*	(5)	99,010,603	66,636,896	37,324,236	2,738,639	2.77	13.6
	FREDERICKSON	06-2030	60-R3	*	(5)	30,004,025	24,750,966	6,753,260	506,008	1.69	13.3
	WHITEHORN 2-3	06-2038	60-R3	*	(5)	33,087,674	30,119,678	4,622,380	216,097	0.65	21.4
	TOTAL GENERATORS					162,678,145	121,913,369	48,898,682	3,478,023	2.14	14.1
344.01	GENERATORS - WIND										
	LOWER SNAKE RIVER	06-2037	40-R2.5	*	(5)	583,581,425	112,902,903	499,857,593	25,258,090	4.33	19.8
	HOPKINS RIDGE	06-2030	40-R2.5	*	(5)	153,525,782	62,513,564	98,688,507	7,495,174	4.88	13.2
	WILD HORSE	06-2031	40-R2.5	*	(5)	372,345,403	136,231,904	254,730,769	18,030,523	4.84	14.1
	TOTAL GENERATORS - WIND					1,109,452,610	311,648,371	853,276,869	50,783,787	4.58	16.8
344.20	GENERATORS - COMBINED CYCLE										
	ENCOGEN	06-2033	12-L0.5	*	20	74,375,981	56,434,886	3,065,899	540,356	0.73	5.7
	FREDERICKSON 1/EPCOR	06-2042	12-L0.5	*	20	26,006,935	1,397,214	19,408,333	2,999,348	11.53	6.5
	GOLDENDALE	06-2044	12-L0.5	*	20	83,514,274	8,066,153	58,745,266	7,147,793	8.56	8.2
	MINT FARM	06-2047	12-L0.5	*	20	32,380,062	2,715,654	23,188,396	2,902,863	8.96	8.0
	SUMAS	06-2033	12-L0.5	*	20	27,973,570	20,284,084	2,094,772	267,769	0.96	7.8
	FERNDALE	06-2034	12-L0.5	*	20	53,610,404	35,341,321	7,547,002	854,758	1.59	8.8
	TOTAL GENERATORS - COMBINED CYCLE					297,861,225	124,239,313	114,049,668	14,712,887	4.94	7.8
345.00	ACCESSORY ELECTRIC EQUIPMENT										
	ENCOGEN	06-2033	45-S1.5	*	(5)	2,021,518	1,613,490	509,104	33,297	1.65	15.3
	FREDERICKSON 1/EPCOR	06-2042	45-S1.5	*	(5)	296,767	111,119	200,486	8,875	2.99	22.6
	GOLDENDALE	06-2044	45-S1.5	*	(5)	9,468,135	7,420,970	2,520,571	101,965	1.08	24.7
	MINT FARM	06-2047	45-S1.5	*	(5)	2,823,972	810,921	2,154,249	79,787	2.83	27.0
	SUMAS	06-2033	45-S1.5	*	(5)	4,392,925	3,714,712	897,859	55,659	1.27	16.1

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Approved Electric Plant Depreciation Rates

Table 1. Summary of Estimated Survivor Curves, Net Salvage Percent, Original Cost, Book Depreciation Reserve and Calculated Annual Depreciation Rates as of September 30, 2016

FERC	ACCOUNT	PROBABLE RETIREMENT DATE	SURVIVOR CURVE	NET SALVAGE PERCENT	ORIGINAL COST AS OF SEPTEMBER 30, 2016	BOOK DEPRECIATION RESERVE	FUTURE ACCRUALS	CALCULATED ANNUAL ACCRUAL AMOUNT	CALCULATED ANNUAL ACCRUAL RATE	COMPOSITE REMAINING LIFE
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)=(8)/(5)	(10)=(7)/(8)
	CRYSTAL MOUNTAIN	06-2028	45-S1.5 *	(5)	406,680	188,927	238,087	20,822	5.12	11.4
	FREDONIA	06-2030	45-S1.5 *	(5)	7,187,908	3,377,315	4,169,989	309,159	4.30	13.5
	FREDERICKSON	06-2030	45-S1.5 *	(5)	2,438,637	1,763,155	797,414	59,300	2.43	13.4
	WHITEHORN 2-3	06-2038	45-S1.5 *	(5)	201,938	172,085	39,950	2,007	0.99	19.9
	FERNDALE	06-2034	45-S1.5 *	(5)	3,521,061	2,410,379	1,286,735	74,292	2.11	17.3
	TOTAL ACCESSORY ELECTRIC EQUIPMENT				32,759,541	21,583,072	12,814,444	745,163	2.27	17.2
345.01	ACCESSORY ELECTRIC EQUIPMENT - WIND									
	LOWER SNAKE RIVER	06-2037	45-S1.5 *	(5)	68,432,625	13,311,771	58,542,486	2,921,282	4.27	20.0
	HOPKINS RIDGE	06-2030	45-S1.5 *	(5)	13,903,073	5,771,433	8,826,794	665,811	4.79	13.3
	WILD HORSE	06-2031	45-S1.5 *	(5)	36,997,248	13,607,937	25,239,173	1,772,155	4.79	14.2
	TOTAL ACCESSORY ELECTRIC EQUIPMENT - WIND				119,332,945	32,691,140	92,608,453	5,359,248	4.49	17.3
346.00	MISCELLANEOUS POWER PLANT EQUIPMENT									
	ENCOGEN	06-2033	45-S1.5 *	(5)	792,721	114,831	717,526	45,000	5.68	15.9
	GOLDENDALE	06-2044	45-S1.5 *	(5)	2,134,388	1,670,587	570,521	23,079	1.08	24.7
	MINT FARM	06-2047	45-S1.5 *	(5)	717,365	200,278	552,956	20,425	2.85	27.1
	SUMAS	06-2033	45-S1.5 *	(5)	2,005,074	1,775,642	329,686	20,465	1.02	16.1
	FREDONIA	06-2030	45-S1.5 *	(5)	353,338	265,750	105,254	7,885	2.23	13.3
	FREDERICKSON	06-2030	45-S1.5 *	(5)	156,088	158,502	5,390	421	0.27	12.8
	WHITEHORN 2-3	06-2038	45-S1.5 *	(5)	46,462	28,650	20,136	1,180	2.54	17.1
	FERNDALE	06-2034	45-S1.5 *	(5)	665,876	455,832	243,337	14,049	2.11	17.3
	TOTAL MISCELLANEOUS POWER PLANT EQUIPMENT				6,871,312	4,670,072	2,544,806	132,504	1.93	19.2
346.01	MISCELLANEOUS POWER PLANT EQUIPMENT - WIND									
	LOWER SNAKE RIVER	06-2037	50-R2.5 *	(5)	2,820,159	548,421	2,412,746	119,799	4.25	20.1
	HOPKINS RIDGE	06-2030	50-R2.5 *	(5)	479,165	120,445	382,678	28,324	5.91	13.5
	WILD HORSE	06-2031	50-R2.5 *	(5)	706,082	166,936	574,450	39,712	5.62	14.5
	TOTAL MISCELLANEOUS POWER PLANT EQUIPMENT - WIND				4,005,406	835,801	3,369,874	187,835	4.69	17.9
346.10	MISCELLANEOUS TOOLS									
	ENCOGEN	06-2028	15-L4 *	0	387,250	108,495	278,755	35,473	9.16	7.9
	FREDERICKSON 1/EPCOR	06-2042	15-L4 *	0	44,162	12,907	31,255	3,992	9.04	7.8
	GOLDENDALE	06-2044	15-L4 *	0	469,810	36,213	433,597	46,133	9.82	9.4
	MINT FARM	06-2047	15-L4 *	0	363,626	61,077	302,549	33,962	9.34	8.9
	SUMAS	06-2033	15-L4 *	0	310,501	29,326	281,175	30,586	9.85	9.2
	CRYSTAL MOUNTAIN	06-2028	15-L4 *	0	10,249	2,694	7,555	2,041	19.91	3.7
	FREDONIA	06-2030	15-L4 *	0	500,057	141,521	358,536	80,315	16.06	4.5
	FREDERICKSON	06-2030	15-L4 *	0	313,151	63,836	249,315	38,756	12.38	6.4
	WHITEHORN 2-3	06-2038	15-L4 *	0	252,403	85,235	167,168	27,048	10.72	6.2

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	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)=(8)/(5)	(10)=(7)/(8)
	TOTAL MISCELLANEOUS TOOLS				2,651,210	541,303	2,109,905	298,306	11.25	7.1
346.11	MISCELLANEOUS TOOLS - WIND									
	LOWER SNAKE RIVER	06-2037	15-L4	* 0	124,261	9,773	114,488	8,911	7.17	12.8
	HOPKINS RIDGE	06-2030	15-L4	* 0	324,715	95,474	229,240	32,087	9.88	7.1
	WILD HORSE	06-2031	15-L4	* 0	333,520	46,846	286,674	25,531	7.66	11.2
	TOTAL MISCELLANEOUS TOOLS - WIND				782,496	152,094	630,402	66,529	8.50	9.5
348.00	*ENERGY STORAGE EQUIPMENT*		20-S3	0	4,776,732	95,635	4,681,096	238,466	4.99	19.6
	TOTAL OTHER PRODUCTION PLANT				**1,895,861,022**	**697,385,810**	**1,218,392,431**	**80,310,360**	**4.24**	
	TRANSMISSION PLANT									
350.10	EASEMENTS		75-R4	0	13,037,871	3,769,178	9,268,693	143,445	1.10	64.6
350.16	EASEMENTS - SUBTRANSMISSION		75-R4	0	2,478,318	(34,424)	2,512,742	34,956	1.41	71.9
350.17	EASEMENTS - HVD RECLASS		75-R4	0	20,438,120	9,201,696	11,236,424	216,465	1.06	51.9
350.99	EASEMENTS - GIF		75-R4	0	172,389	39,559	132,830	2,066	1.20	64.3
352.00	STRUCTURES AND IMPROVEMENTS		65-R4	(5)	3,818,788	1,232,451	2,777,276	58,188	1.52	47.7
352.60	STRUCTURES AND IMPROVEMENTS - SUBTRANSMISSION		65-R4	(5)	1,759,634	68,052	1,779,564	28,096	1.60	63.3
352.70	STRUCTURES AND IMPROVEMENTS - HVD RECLASS		65-R4	(5)	2,270,219	1,182,926	1,200,804	29,883	1.32	40.2
352.90	STRUCTURES AND IMPROVEMENTS - GIF		65-R4	(5)	1,956,304	298,138	1,755,981	29,470	1.51	59.6
353.00	STATION EQUIPMENT		45-R1.5	(10)	157,933,119	45,791,174	127,935,257	3,642,533	2.31	35.1
353.60	STATION EQUIPMENT - SUBTRANSMISSION		45-R1.5	(10)	108,797,057	6,534,012	113,142,750	2,669,975	2.45	42.4
353.70	STATION EQUIPMENT - HVD RECLASS		45-R1.5	(10)	198,771,432	67,306,052	151,342,523	4,951,422	2.49	30.6
353.80	STATION EQUIPMENT - LIF		45-R1.5	(10)	405,246	193,972	251,799	9,978	2.46	25.2
353.90	STATION EQUIPMENT - GIF		45-R1.5	(10)	129,568,729	38,323,242	104,202,360	2,697,721	2.08	38.6
354.00	TOWERS AND FIXTURES		75-R4	(15)	90,563,276	43,514,475	60,633,293	1,136,178	1.25	53.4
354.70	TOWERS AND FIXTURES - HVD RECLASS		75-R4	(15)	1,507,253	896,631	836,709	16,945	1.12	49.4
354.90	TOWERS AND FIXTURES - GIF		75-R4	(15)	133,399	110,351	43,058	609	0.46	70.7
355.00	POLES AND FIXTURES		43-R1	(40)	85,130,848	27,928,206	91,254,981	2,587,052	3.04	35.3
355.60	POLES AND FIXTURES - SUBTRANSMISSION		43-R1	(40)	78,708,415	4,825,666	105,366,116	2,559,412	3.25	41.2
355.70	POLES AND FIXTURES - HVD RECLASS		43-R1	(40)	170,738,424	47,576,643	191,457,151	5,810,001	3.40	33.0
355.90	POLES AND FIXTURES - GIF		43-R1	(40)	8,879,281	2,097,318	10,333,675	274,655	3.09	37.6
356.00	OVERHEAD CONDUCTORS AND DEVICES		60-R2.5	(10)	127,496,955	69,844,695	70,401,955	1,643,066	1.29	42.8
356.60	OVERHEAD CONDUCTORS AND DEVICES - SUBTRANSMISSI(		60-R2.5	(10)	25,127,106	1,384,144	26,255,673	455,609	1.81	57.6
356.70	OVERHEAD CONDUCTORS AND DEVICES - HVD RECLASS		60-R2.5	(10)	132,747,969	70,324,578	75,698,188	1,743,446	1.31	43.4
356.90	OVERHEAD CONDUCTORS AND DEVICES - GIF		60-R2.5	(10)	6,269,538	1,610,720	5,285,772	100,331	1.60	52.7
357.70	UNDERGROUND CONDUIT - HVD RECLASS		55-R4	0	700,575	375,467	325,108	17,834	2.55	18.2
357.90	UNDERGROUND CONDUIT - GIF		55-R4	0	510,284	114,486	395,799	8,839	1.73	44.8
358.70	UNDERGROUND CONDUCTORS AND DEVICES - HVD RECLA!		55-R4	0	2,932,873	2,515,857	417,016	21,673	0.74	19.2

Exhibit B to the Multiparty Settlement Stipulation and Agreement

Docket Nos. UE-170033 and UG-170034

Approved Electric Plant Depreciation Rates

Table 1. Summary of Estimated Survivor Curves, Net Salvage Percent, Original Cost, Book Depreciation Reserve and Calculated Annual Depreciation Rates as of September 30, 2016

FERC	ACCOUNT	PROBABLE RETIREMENT DATE	SURVIVOR CURVE	NET SALVAGE PERCENT	ORIGINAL COST AS OF SEPTEMBER 30, 2016	BOOK DEPRECIATION RESERVE	FUTURE ACCRUALS	CALCULATED ANNUAL ACCRUAL AMOUNT	CALCULATED ANNUAL ACCRUAL RATE	COMPOSITE REMAINING LIFE
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)=(8)/(5)	(10)=(7)/(8)
358.90	UNDERGROUND CONDUCTORS AND DEVICES - GIF		55-R4	0	34,023,857	8,177,268	25,846,588	527,144	1.55	49.0
359.00	ROADS AND TRAILS		65-R4	0	1,379,629	397,494	982,136	19,310	1.40	50.9
359.70	ROADS AND TRAILS - HVD RECLASS		65-R4	0	568,185	279,529	288,657	9,535	1.68	30.3
359.99	ROADS AND TRAILS - GIF		65-R4	0	8,021	3,313	4,708	117	1.46	40.2
	TOTAL TRANSMISSION PLANT				**1,408,833,111**	**455,882,866**	**1,193,365,586**	**31,445,954**	**2.23**	
	DISTRIBUTION PLANT									
360.10	EASEMENTS		65-R4	0	6,192,998	3,154,464	3,038,534	69,962	1.13	43.4
361.00	STRUCTURES AND IMPROVEMENTS		60-R2	(10)	7,980,827	2,327,041	6,451,869	140,499	1.76	45.9
362.00	STATION EQUIPMENT		52-S0	(15)	434,912,649	125,213,289	374,936,256	8,871,422	2.04	42.3
363.00	BATTERY STORAGE EQUIPMENT		20-S3	0	1,194,183	23,909	1,170,274	59,617	4.99	19.6
364.00	POLES, TOWERS AND FIXTURES		46-R1.5	(50)	340,904,415	146,427,147	364,929,476	10,713,901	3.14	34.1
365.00	OVERHEAD CONDUCTORS AND DEVICES		38-R2.5	(25)	409,216,187	120,401,105	391,119,128	15,306,553	3.74	25.6
366.00	UNDERGROUND CONDUIT		55-R3	(10)	672,272,623	261,027,349	478,472,536	11,912,719	1.77	40.2
367.00	UNDERGROUND CONDUCTORS AND DEVICES		38-R2.5	(40)	844,856,752	341,308,280	841,491,174	33,220,993	3.93	25.3
368.00	LINE TRANSFORMERS		44-R2	(50)	462,673,681	181,111,959	512,898,561	18,805,777	4.06	27.3
369.00	SERVICES		55-R3	(60)	182,057,677	116,569,686	174,722,597	5,727,599	3.15	30.5
370.00	METERS		20-L1	(10)	140,665,914	34,679,835	120,052,670	11,730,432	8.34 *	10.2
373.00	STREET LIGHTING AND SIGNAL SYSTEMS		31-S0.5	(15)	53,727,968	18,793,323	42,993,840	2,552,518	4.75	16.8
	TOTAL DISTRIBUTION PLANT				**3,556,655,873**	**1,351,037,388**	**3,312,276,915**	**119,111,992**	**3.35**	
	GENERAL PLANT									
390.00	STRUCTURES AND IMPROVEMENTS									
	SKAGIT	06-2057	75-S1.5 *	(5)	20,916,098	7,596,119	14,365,784	374,164	1.79	38.4
	OTHER STRUCTURES		45-S1.5	(5)	27,691,075	20,042,691	9,032,937	261,922	0.95	34.5
	TOTAL STRUCTURES AND IMPROVEMENTS				48,607,173	27,638,810	23,398,721	636,086	1.43	36.6
391.10	OFFICE FURNITURE AND EQUIPMENT									
	FULLY ACCRUED		FULLY ACCRUED	0	5,896,620	5,896,620	0	0	-	-
	AMORTIZED		20-SQ	0	4,398,911	2,177,000	2,221,911	219,874	5.00	10.1
	TOTAL OFFICE FURNITURE AND EQUIPMENT				10,295,531	8,073,620	2,221,911	219,874	2.14	10.5
391.20	OFFICE FURNITURE AND EQUIPMENT - COMPUTERS		5-SQ	0	22,169,282	13,532,000	8,637,282	4,433,881	20.00	1.9
392.00	TRANSPORTATION EQUIPMENT		12-L3	10	9,188,876	5,273,638	2,996,351	482,333	5.25	6.2

Exhibit B to the Multiparty Settlement Stipulation and Agreement

Docket Nos. UE-170033 and UG-170034

Approved Electric Plant Depreciation Rates

Table 1. Summary of Estimated Survivor Curves, Net Salvage Percent, Original Cost, Book Depreciation Reserve and Calculated Annual Depreciation Rates as of September 30, 2016

FERC	ACCOUNT	PROBABLE RETIREMENT DATE	SURVIVOR CURVE	NET SALVAGE PERCENT	ORIGINAL COST AS OF SEPTEMBER 30, 2016	BOOK DEPRECIATION RESERVE	FUTURE ACCRUALS	CALCULATED ANNUAL ACCRUAL AMOUNT	CALCULATED ANNUAL ACCRUAL RATE	COMPOSITE REMAINING LIFE
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)=(8)/(5)	(10)=(7)/(8)
393.00	STORES EQUIPMENT									
	FULLY ACCRUED		FULLY ACCRUED	0	589,596	589,596	0	0	-	-
	AMORTIZED		20-SQ	0	170,969	33,600	137,369	8,552	5.00	16.1
	TOTAL STORES EQUIPMENT				760,565	623,196	137,369	8,552	0.99	16.4
394.00	TOOLS, SHOP AND GARAGE EQUIPMENT									
	FULLY ACCRUED		FULLY ACCRUED	0	3,661,295	3,661,295	0	0	-	-
	AMORTIZED		20-SQ	0	8,917,578	2,134,000	6,783,578	445,520	5.00	15.2
	TOTAL TOOLS, SHOP AND GARAGE EQUIPMENT				12,578,873	5,795,295	6,783,578	445,520	3.61	15.7
395.00	LABORATORY EQUIPMENT									
	FULLY ACCRUED		FULLY ACCRUED	0	4,155,876	4,155,876	0	0	-	-
	AMORTIZED		20-SQ	0	7,875,250	3,991,000	3,884,250	393,582	5.00	9.9
	TOTAL LABORATORY EQUIPMENT				12,031,127	8,146,876	3,884,250	393,582	3.40	10.5
396.00	POWER OPERATED EQUIPMENT		14-L3	10	6,082,762	2,469,391	3,005,095	400,413	6.58	7.5
397.00	COMMUNICATION EQUIPMENT									
	FULLY ACCRUED		FULLY ACCRUED	0	12,913,083	12,913,083	0	0	-	-
	AMORTIZED		15-SQ	0	80,874,473	28,500,000	52,374,473	5,396,167	6.67	9.7
	TOTAL COMMUNICATION EQUIPMENT				93,787,556	41,413,083	52,374,473	5,396,167	5.81	10.3
398.00	MISCELLANEOUS EQUIPMENT									
	FULLY ACCRUED		FULLY ACCRUED	0	86,544	86,544	0	0	-	-
	AMORTIZED		15-SQ	0	190,786	67,100	123,686	12,718	6.67	9.7
	TOTAL MISCELLANEOUS EQUIPMENT				277,330	153,644	123,686	12,718	4.47	10.3
	TOTAL GENERAL PLANT				**215,779,075**	**113,119,553**	**103,562,716**	**12,429,126**	**5.76**	
	UNRECOVERED RESERVE TO BE AMORTIZED									
391.10	OFFICE FURNITURE AND EQUIPMENT					(1,913,644)		382,729 ***		
391.20	OFFICE FURNITURE AND EQUIPMENT - COMPUTERS					20,333		(4,067) ***		
393.00	STORES EQUIPMENT					(384,429)		76,886 ***		
394.00	TOOLS, SHOP AND GARAGE EQUIPMENT					(798,799)		159,760 ***		
395.00	LABORATORY EQUIPMENT					(3,153,918)		630,784 ***		
397.00	COMMUNICATION EQUIPMENT					(7,646,069)		1,529,214 ***		
398.00	MISCELLANEOUS EQUIPMENT					(63,957)		12,791 ***		

Approved Electric Plant Depreciation Rates

Table 1. Summary of Estimated Survivor Curves, Net Salvage Percent, Original Cost, Book Depreciation Reserve and Calculated Annual Depreciation Rates as of September 30, 2016

FERC	ACCOUNT	PROBABLE RETIREMENT DATE	SURVIVOR CURVE	NET SALVAGE PERCENT	ORIGINAL COST AS OF SEPTEMBER 30, 2016	BOOK DEPRECIATION RESERVE	FUTURE ACCRUALS	CALCULATED ANNUAL ACCRUAL AMOUNT	CALCULATED ANNUAL ACCRUAL RATE	COMPOSITE REMAINING LIFE
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)=(8)/(5)	(10)=(7)/(8)
	TOTAL UNRECOVERED RESERVE TO BE AMORTIZED					**(13,940,483)**		**2,788,097**		
	TOTAL DEPRECIABLE PLANT				**9,059,147,131**	**3,365,813,561**	**6,844,316,106**	**314,477,971**		
NONDEPRECIABLE PLANT AND ACCOUNTS NOT STUDIED										
301.00	ORGANIZATION				114,202					
302.00	FRANCHISES AND CONSENTS				55,290,806	10,926,343				
303.00	MISCELLANEOUS INTANGIBLES				64,531,940	23,833,179				
310.00	LAND AND LAND RIGHTS				3,795,193					
317.00	ARO				252,964	71,227				
317.10	ARO				35,282,326	2,724,424				
330.00	LAND AND LAND RIGHTS				6,106,995					
337.00	ARO				-					
340.00	LAND AND LAND RIGHTS				15,794,832					
347.00	ARO				35,764,903	3,237,154				
350.00	LAND AND LAND RIGHTS				3,261,663					
350.70	LAND AND LAND RIGHTS				11,102,367					
350.90	LAND AND LAND RIGHTS				1,908					
359.90	ARO				5,387,662	84,806				
360.00	LAND AND LAND RIGHTS				31,113,741	9				
374.00	ARO				2,696,910	315,002				
389.00	LAND AND LAND RIGHTS				5,316,208					
390.10	STRUCTURES AND IMPROVEMENTS - LEASEHOLDS				184,776	170,844				
	TOTAL NONDEPRECIABLE PLANT				**275,999,394**	**41,362,988**				
	TOTAL ELECTRIC PLANT				**9,335,146,525**	**3,407,176,548**	**6,844,316,106**	**314,477,971**		

* LIFE SPAN PROCEDURE USED. CURVE SHOWN IS INTERIM SURVIVOR CURVE.

** FOR NEW ADDITIONS FOR AMI METERS, THE RECOMMENDATION IS A 20-S2.5 SURVIVOR CURVE, (10) NET SALVAGE AND A 5.50% DEPRECIATION RATE.

*** 5-YEAR AMORTIZATION OF UNRECOVERED RESERVE RELATED TO AMORTIZATION ACCOUNTING.

NOTE: FOR NEW ASSETS FOR THE COMPANY'S EQUIPMENT LEASE PROGRAM, THE FOLLOWING ESTIMATES AND DEPRECIATION RATES ARE RECOMMENDED:

	LIFE	NET SALVAGE	RATE
RESIDENTIAL HEAT PUMPS	18-S3	0	5.56
RESIDENTIAL WATER HEATERS	15-L3	0	6.67
COMMERCIAL WATER HEATERS	10-L3	0	10.00

Exhibit B to the Multiparty Settlement Stipulation and Agreement

Docket Nos. UE-170033 and UG-170034

Approved Depreciation Rates for Colstrip Units 1 and 2

Summary of Estimated Suvivor Curves, Original Cost, Book Reserve, Theoretical Reserve and Whole Life Depreciation Accruals and Rates as of September 30, 2016

	ACCOUNT	ORIGINAL COST AS OF SEPTEMBER 30, 2016	BOOK DEPRECIATION RESERVE	THEORETICAL RESERVE	THEORETICAL RESERVE IMBALANCE AMOUNT	WHOLE LIFE ANNUAL ACCRUA AMOUNT	RATE
	(1)	(2)	(3)	(4)	(5)=(3)-(4)	(6)	(7)
	ELECTRIC PLANT						
	STEAM PRODUCTION PLANT						
311.00	STRUCTURES AND IMPROVEMENTS						
	COLSTRIP 1	9,209,467.84	5,369,108	6,652,518	(1,283,410)	447,725	4.86
	COLSTRIP 2	4,336,957.28	1,063,479	2,494,123	(1,430,644)	321,879	7.42
	COLSTRIP 1-2	30,934,199.88	26,913,191	26,335,450	577,741	808,539	2.61
	TOTAL STRUCTURES AND IMPROVEMENTS	44,480,625.00	33,345,777	35,482,091	(2,136,314)	1,578,143	3.55
312.00	BOILER PLANT EQUIPMENT						
	COLSTRIP 1	88,145,747.64	42,279,305	57,146,892	(14,867,587)	5,451,528	6.18
	COLSTRIP 2	88,368,523.22	36,998,692	54,704,019	(17,705,328)	5,914,163	6.69
	COLSTRIP 1-2	6,043,572.10	5,184,007	5,195,394	(11,387)	151,538	2.51
	TOTAL BOILER PLANT EQUIPMENT	182,557,842.96	84,462,004	117,046,305	(32,584,301)	11,517,229	6.31
314.00	TURBOGENERATOR UNITS						
	COLSTRIP 1	28,781,740.46	9,901,631	17,820,709	(7,919,078)	1,952,444	6.78
	COLSTRIP 2	34,145,118.66	12,039,663	21,361,548	(9,321,885)	2,277,281	6.67
	COLSTRIP 1-2	3,813,725.50	3,575,882	3,255,399	320,483	105,285	2.76
	TOTAL TURBOGENERATOR UNITS	66,740,584.62	25,517,176	42,437,656	(16,920,480)	4,335,010	6.5
315.00	ACCESSORY ELECTRIC EQUIPMENT						
	COLSTRIP 1	7,465,362.62	4,686,400	5,200,491	(514,091)	399,892	5.36
	COLSTRIP 2	4,167,725.42	1,460,588	2,615,195	(1,154,607)	272,129	6.53
	COLSTRIP 1-2	2,272,860.64	1,998,202	1,978,529	19,673	53,628	2.36
	TOTAL ACCESSORY ELECTRIC EQUIPMENT	13,905,948.68	8,145,190	9,794,215	(1,649,025)	725,649	5.22

Exhibit B to the Multiparty Settlement Stipulation and Agreement

Docket Nos. UE-170033 and UG-170034

Approved Depreciation Rates for Colstrip Units 1 and 2

Summary of Estimated Suvivor Curves, Original Cost, Book Reserve, Theoretical Reserve and
Whole Life Depreciation Accruals and Rates as of September 30, 2016

	ACCOUNT	ORIGINAL COST AS OF SEPTEMBER 30, 2016	BOOK DEPRECIATION RESERVE	THEORETICAL RESERVE	THEORETICAL RESERVE IMBALANCE AMOUNT	WHOLE LIFE ANNUAL ACCRUA AMOUNT	RATE
	(1)	(2)	(3)	(4)	(5)=(3)-(4)	(6)	(7)
316.00	MISCELLANEOUS POWER PLANT EQUIPMENT						
	COLSTRIP 1	946,611.59	373,569	585,561	(211,992)	63,866	6.75
	COLSTRIP 2	1,075,704.32	483,996	692,357	(208,361)	67,982	6.32
	COLSTRIP 1-2	6,205,596.72	5,331,195	5,084,569	246,626	202,687	3.27
	TOTAL MISCELLANEOUS POWER PLANT EQUIPMENT	8,227,912.63	6,188,760	6,362,487	(173,727)	334,535	4.07
	TOTAL STEAM PRODUCTION PLANT	**315,912,913.89**	**157,658,907**	**211,122,754**	**(53,463,847)**	**18,490,566**	**5.85**
	TOTAL ELECTRIC PLANT	**315,912,913.89**	**157,658,907**	**211,122,754**	**(53,463,847)**	**18,490,566**	**5.85**

Exhibit C to the Multiparty Settlement Stipulation and Agreement

Exhibit C to the Multiparty Settlement Stipulation and Agreement
Dockets UE-170033 and UG-170034
Adjustment to Investor-Supplied Working Capital and Rate Base (ISWC)

For the Twelve Months Ended September 30, 2016

LINE NO.	(a) Description	PSE WP - "5.03 E&G RB - 5.04 E&G WC 17GRC.xlsx" (b) AMA	ADJUSTMENT (c) = (d) - (b) AMA	FINAL WORKING CAPITAL (d) AMA
1	**AVERAGE INVESTED CAPITAL**			
2	Total Average Invested Capital	7,389,220,147	(0)	7,389,220,147
3				
4	**INVESTMENTS**			
5				
6	**Electric (Rate Base and Deferrals)**			
7				
8	Total Electric (Rate Base and Deferrals)	4,961,861,442	(35,662,222)	4,926,199,220
9				
10	**Gas (Rate Base and Deferrals)**			
11				
12	Total Gas (Rate Base and Deferrals)	1,697,061,852	(47,382,699)	1,649,679,153
13				
14	Total Electric & Gas Investment	6,658,923,294	(83,044,921)	6,575,878,373
15				
16				
17	**Non-Operating**			
18				
19	Total Non Operating Investment	425,115,043	36,765,423	461,880,466
20				
21	Total Average Investments	7,084,038,337	(46,279,499)	7,037,758,839
22	Rounding			
23	Total Investor Supplied Capital	$ 305,181,810	$ 46,279,499	$ 351,461,308
24				
25				
26	**INVESTED SUPPLIED WORKING CAPITAL**			
27				
28	**Electric Working Capital**	**$ 227,005,242**	19,006,090	**$ 246,011,332**
29	Electric Allocation (Line 28 / Line 23)	74.38%		70.00%
30	**Gas Working Capital**	**$ 77,640,607**	4,743,346	**$ 82,383,953**
31	Gas Allocation (Line 30 / Line 23)	25.44%		23.44%
32	**Non Operating Working Capital**	**$ 535,961**	22,530,063	**$ 23,066,024**
33	Non-Operating Allocation (Line 32 / Line 23)	0.18%		6.56%

Exhibit D to the Multiparty Settlement Stipulation and Agreement

Exhibit D to the Multiparty Settlement Stipulation and Agreement
Dockets UE-170033 and UG-170034
CAISO Energy Imbalance Market Costs

Description	Reference	Annual in Sch B	Monthly in Sch B
557 Costs	Exhibit PKW-22C	$ 2,333	$ 194.4
Plant Related Depreciation and Return	(a)	6,126	510.5
Amount to be included in Adjustment Section of Schedule B		$ 8,459	$ 704.9

Line	*(a) EIM Plant Related Costs*			
1				***Reference***
2	Cost of Debt		2.99%	KJB-18.02
3	ROR per Settlement		7.60%	Settlement
4	Rate Year EIM Rate Base		$5,132	KJB-21.08
5	Variable Prod Factor		0.961606	KJB-18.03
6				
7	NOI of Plant Costs in KJB		($3,493)	KJB-21.08
8	Tax Benefit of Proforma Interest		54	Line 2 x 4 x 35%
9	Return on Rate Base		(390)	Line 3 x 4
10	Total Rate Base Related Costs		$3,829	
11	Pre-tax		5,891	Line 10 ÷ 65%
12	Pre-Production Factored Plant Related Cost	(a) ===>	$6,126	Line 11÷ Line 5
13				

Exhibit E to the Multiparty Settlement Stipulation and Agreement

Exhibit E to the Multiparty Settlement Stipulation and Agreement
Dockets UE-170033 and UG-170034
Power Cost Adjustment

For the Twelve Months Ended September 30, 2016

LINE NO.	DESCRIPTION	ACTUAL	PROFORMA	INCREASE (DECREASE)
1	PRODUCTION EXPENSES:			
2	501-STEAM FUEL	$ 85,246,015	$ 69,962,949	$ (15,283,065)
3	547-FUEL	149,756,872	171,115,374	21,358,502
4	555-PURCHASED POWER	523,037,996	378,349,380	(144,688,616)
5	557-OTHER POWER EXPENSE	9,308,464	7,410,673	(1,897,791)
6	565-WHEELING	113,800,193	108,374,278	(5,425,915)
7	447-SALES FOR RESALE	(201,125,742)	(36,228,867)	164,896,875
8	456-PURCHASES/SALES OF NON-CORE GAS	18,023,678	(16,223,873)	(34,247,551)
9	PRODUCTION O&M	125,897,437	137,871,323	11,973,886
10	TRANS. EXP. INCL. 500KV O&M	662,135	662,135	-
11	456-1 VARIABLE TRANSM. INCOME - COLSTRIP, 3	(8,228,549)	(11,639,833)	(3,411,285)
12	EQUITY RETURN ON CENTRALIA TRANSITION COAL PPA		4,769,481	4,769,481
13	INCREASE (DECREASE) EXPENSE	816,378,499	814,423,019	(1,955,479)
14				
15	INCREASE (DECREASE) OPERATING INCOME	(816,378,499)	(814,423,019)	1,955,479
16				
17	STATE UTILITY TAX SAVINGS FOR LINE 12	3.873%		(132,133)
18	INCREASE (DECREASE) INCOME			1,823,347
19	INCREASE (DECREASE) FIT @	35%		638,171
20	INCREASE (DECREASE) NOI			$ 1,185,175

Exhibit E to Multiparty Settlement Stipulation and Agreement
Dockets UE-170033 and UG-170034
Power Cost Bridge

For the Twelve Months Ended September 30, 2016

1											Factor	Complement
2												
3											Fixed PF	Fixed PF
4											0.000%	100.000%
5											Variable PF	Variable PF
6											3.839%	0.961606000
7				12MOE SAP	ETIF	Remove	Remove	Net	12MOE	Reclass	Net Before	Production
8	FERC	F/V		9/30/2016	Reported in FERC	Benefits	Payroll Tax	Test Year	12/31/2018	Ben & Tax	Prod Factor	Factored
9	a	b	c	d	e	f	g	h	i	j	k	l
10	501	V	Steam Fuel	$ 85,246,015	$ -	$ -	$ -	$ 85,246,015	$ 72,756,357	$ -	$ 72,756,357	$ 69,962,949
11	547	V	GFG Fuel	149,756,872				149,756,872	177,947,490		177,947,490	171,115,374
12	555	V	Purchased Power	375,700,425	147,337,571			523,037,996	393,455,718		393,455,718	378,349,380
13	557	F	Other Power Expense	10,715,288		(1,364,051)	(368,616)	8,982,621	8,830,007	(1,732,667)	7,097,341	7,097,341
14	557	V	Brokerage Fees	325,842				325,842	325,842		325,842	313,332
15	565	V	Wheeling	113,800,193				113,800,193	112,701,333		112,701,333	108,374,278
16	447	V	Sales for Resale	(53,788,171)	(147,337,571)			(201,125,742)	(37,675,375)		(37,675,375)	(36,228,867)
17	456	V	Purchses/(Sales) of Non-Core Gase	18,023,678				18,023,678	(16,871,643)		(16,871,643)	(16,223,873)
18	Net power costs from TY Margin or RY DEM Exh			699,780,142	-	(1,364,051)	(368,616)	698,047,475	711,469,730	(1,732,667)	709,737,064	682,759,914
19			check=>	-								
20	various	F	Production O&M	133,910,147		(6,304,989)	(1,707,721)	125,897,437	145,884,033	(8,012,710)	137,871,323	137,871,323
21	various	F	500KV Trans Exp/O&M	662,135				662,135	662,135		662,135	662,135
22	456-17	F	OATT Transmission Revenue	(8,228,549)				(8,228,549)	(11,639,833)		(11,639,833)	(11,639,833)
23	n/a	V	Equity Return on Centralia Coal Transition PPA					-	4,959,912		4,959,912	4,769,481
24	Total Power Cost Adjustment			$ 826,123,875	$ -	$ (7,669,040)	$ (2,076,336)	$ 816,378,499	$ 851,335,976	$ (9,745,377)	$ 841,590,600	$ 814,423,019
			check=>	-			check=>	-			check=>	-

Exhibit E to Multiparty Settlement Stipulation and Agreement
Dockets UE-170033 and UG-170034
2017 GRC Settlement Power Costs Projections - AURORA + Not in Models

Rate Year January 2018 through December 2018
Gas Price date: June 23, 2017
(dollars are in thousands)

2017 GRC Settlement - Prices at June 23, 2017

		Jan-18	Feb-18	Mar-18	Apr-18	May-18	Jun-18	Jul-18	Aug-18	Sep-18	Oct-18	Nov-18	Dec-18	17GRC Settlement	17GRC Rebuttal	Change
501	Coal Fuel	$ 7,667	$ 7,191	$ 7,080	$ 4,766	$ 3,346	$ 3,126	$ 6,281	$ 6,821	$ 6,270	$ 6,376	$ 6,546	$ 7,286	$ 72,756	$ 72,991	$ (234)
547	Natural Gas Fuel	$ 18,771	$ 19,557	$ 15,194	9,556	5,590	7,523	13,985	17,825	17,035	16,964	17,158	18,790	177,947	153,808	24,139
555	Purchase & Interchang	$ 43,000	$ 34,643	$ 36,005	32,074	32,646	27,718	24,622	20,857	24,146	28,289	37,953	51,503	393,456	418,488	(25,032)
557	Other Power Supply	$ 763	$ 763	$ 763	763	763	763	763	763	763	763	763	763	9,156	11,489	(2,333)
565	Wheeling	$ 9,559	$ 9,610	$ 9,696	9,545	9,484	9,255	9,177	9,228	9,151	9,230	9,322	9,444	112,701	112,629	73
447	Secondary Sales	$ (2,117)	$ (4,041)	$ (1,802)	(1,601)	(1,445)	(1,758)	(7,431)	(8,449)	(6,243)	(2,117)	(584)	(87)	(37,675)	(37,644)	(32)
456	Non-Core Gas	$ (2,712)	$ (2,132)	$ (1,362)	(740)	(549)	(523)	(1,026)	(853)	(947)	(1,482)	(1,664)	(2,880)	(16,872)	(16,904)	32
	Total Power Costs	$ 74,932	$ 65,591	$ 65,573	$ 54,363	$ 49,836	$ 46,104	$ 46,371	$ 46,191	$ 50,175	$ 58,023	$ 69,492	$ 84,819	$ 711,470	$ 714,857	$ (3,387)
	Load in MWh	2,347,334	2,023,152	2,120,831	1,849,726	1,709,643	1,653,015	1,717,662	1,730,905	1,672,253	1,858,747	2,085,376	2,503,903	23,272,547	23,272,547	-

Exhibit E to Multiparty Settlement Stipulation and Agreement
Dockets UE-170033 and UG-170034
Production O&M

For the Twelve Months Ended September 30, 2016

			Settlement: Adjusted Wind	Rebuttal	Change from Rebuttal
Resources	Test Year 10/01/2015 - 09/30/2016	Adjustments	2017 GRC Jan - Dec 2018	2017 GRC Jan - Dec 2018	2017 GRC Update vs. Update w/ revised Wx
Colstrip 1/2	23,127,394	3,088,660	26,216,054	26,216,054	-
Colstrip 3/4	16,143,246	2,073,771	18,217,016	18,217,016	-
Lower Baker	4,763,084	-	4,763,084	4,763,084	-
Upper Baker	4,413,567	-	4,413,567	4,413,567	-
Baker License	2,499,722	-	2,499,722	2,499,722	-
Electron	10,335	(10,335)	-	-	-
Snoqualmie 1/2	5,169,224	-	5,169,224	5,169,224	-
Snoqualmie License	403,706	-	403,706	403,706	-
Hopkins Ridge	6,507,378	254,159	6,761,537	6,572,112	189,426
Wild Horse	10,879,887	375,984	11,255,871	11,136,003	119,868
Wild Horse Expansion	1,278,119	(142,219)	1,135,900	1,132,441	3,460
Lower Snake River	12,395,839	2,656,948	15,052,788	14,893,042	159,746
Crystal	149,181	-	149,181	149,181	-
Encogen	4,456,797	1,653,961	6,110,758	6,110,758	-
Ferndale	6,079,604	320,966	6,400,569	6,400,569	-
Freddie 1	4,137,387	1,078,811	5,216,199	5,216,199	-
Frederickson	2,149,800	187,572	2,337,372	2,337,372	-
Fredonia 1-4	3,508,973	-	3,508,973	3,508,973	-
Goldendale	8,641,557	(445,719)	8,195,838	8,195,838	-
Mint Farm	7,904,641	(184,794)	7,719,847	7,719,847	-
Sumas	4,726,636	695,333	5,421,970	5,421,970	-
Whitehorn 1-4	1,620,957	370,788	1,991,745	1,991,745	-
Sys Control & Dispatch	31,426	-	31,426	31,426	-
Undistrib/Other Including Incentive Clearing, Compliance	2,911,685	-	2,911,685	2,911,685	-
Centralia	-	-	-	-	-
Prod. O&M incl. Benefits/Taxes	133,910,147	11,973,886	145,884,033	145,411,533	472,499

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Exhibit E to Multiparty Settlement Stipulation and Agreement

Dockets UE-170033 and UG-170034

Montana Electric Energy Tax Adjustment

For the Twelve Months Ended September 30, 2016

LINE NO.	DESCRIPTION		PROFORMA	AMOUNT
1	RATE YEAR KWH		3,833,803,119	
2	TRANSMISSION LINE LOSS % FOR WECC		5.0%	
3	WETT TAX RATE		0.00015	
4	WETT Tax		$ 546,317	
5				
6	EEELT TAX RATE		0.0002	
7	EEELT Tax		$ 766,761	
8				
9	RESTATED ENERGY TAX (LINE 1 X LINE 2)			########
10	CHARGED TO EXPENSE			1,540,793
11	INCREASE (DECREASE) INCOME			227,716
12				
13	INCREASE (DECREASE) FIT @	35%		79,700
14	INCREASE (DECREASE) NOI			$ 148,016

Exhibit F to the Multiparty Settlement Stipulation and Agreement

Exhibit F to the Multiparty Settlement Stipulation and Agreement
Dockets UE-170033 and UG-170034
Storm Adjustment

For the Twelve Months Ended September 30, 2016

LINE NO.	DESCRIPTION			AMOUNT
	NORMAL STORMS			
1		**Transmission**	**Distribution**	**Total**
2	ACTUAL O&M:			
3	TWELVE MONTHS ENDED 09/30/11	146,578	9,324,413	9,470,991
4	TWELVE MONTHS ENDED 09/30/12	330,554	11,614,288	11,944,841
5	TWELVE MONTHS ENDED 09/30/13	115,489	5,128,915	5,244,404
6	TWELVE MONTHS ENDED 09/30/14	427,808	12,676,576	13,104,384
7	TWELVE MONTHS ENDED 09/30/15	718,706	12,394,592	13,113,298
8	TWELVE MONTHS ENDED 09/30/16	506,069	10,553,488	11,059,557
9	TOTAL NORMAL STORMS	2,245,204	61,692,271	63,937,475
10				
11	SIX-YEAR AVERAGE STORM EXPENSE FOR RATE YEAR (LINE 9 ÷ 6 YEAF	374,201	10,282,045	10,656,246
12				
13	CHARGED TO EXPENSE 12 MONTH ENDED 09/30/16			
14	STORM DAMAGE EXPENSE (LINE 8)	506,069	10,553,488	11,059,557
15				
16	INCREASE (DECREASE) OPERATING EXPENSE (LINE 11-LINE 14)	(131,868)	(271,443)	(403,311)
	CATASTROPHIC STORMS			
19	DEFERRED BALANCES FOR UE-090704 4 YEAR AMORTIZATION			
20	AT START OF RATE YEAR (01/31/2018):			
21	2010 STORM DAMAGE	-		
22	2010 STORM DAMAGE PENDING APPROVAL	50,186		
23	2014 STORM DAMAGE-PENDING APPROVAL	18,185,673		
24	2015 STORM DAMAGE-PENDING APPROVAL	24,157,767		
25	**2016 STORM DAMAGE-PENDING APPROVAL**	10,437,020		
26	**2017 STORM DAMAGE-PENDING APPROVAL**	12,215,519		
27	TOTAL (LINE 21 THROUGH LINE 26)	65,046,165		
28	ANNUAL AMORTIZATION (LINE 27 ÷ 48) x 12		16,261,541	
29				
30				
31	DEFERRED BALANCES FOR 10 YEAR AMORTIZATION AT			
32	START OF RATE YEAR (01/31/18):			
33	12/13/06 WIND STORM	-		
34	ORIGINAL AMORT PERIOD FROM UE-072300 WAS 10 YEARS, NOV 2008 - OCT 2018			
35	ANNUAL AMORTIZATION (LINE 33 ¸ 10 (01/2018 - 10/2018) x 10)		-	
36				
37	DEFERRED BALANCES FOR 6 YEAR AMORTIZATION AT			
38	01/18/12 SNOW STORM - PENDING APPROVAL	54,368,273		
39	ANNUAL AMORTIZATION (LINE 38 ¸ 72 (6 YEARS) X 12)		9,061,379	
40				
41	TOTAL RATE YEAR AMORTIZATION (LINE 28 + LINE 35 + LINE 39)		25,322,920	
42	LESS TOTAL TEST YEAR AMORTIZATION		15,477,396	
43				
44	INCREASE (DECREASE) OPERATING EXPENSE			9,845,524
45				
46	TOTAL INCREASE (DECREASE) OPERATING EXPENSE (LINE 16 + LINE 44)			9,442,213
47				
48	INCREASE (DECREASE) FIT @ 35% (LINE 46 X 35%)			(3,304,774)
49				
50	INCREASE (DECREASE) NOI			$ (6,137,438)

Exhibit G to the Multiparty Settlement Stipulation and Agreement

Exhibit G to the Multiparty Settlement Stipulation and Agreement
Dockets UE-170033 and UG-170034
Production Adjustment

LINE NO.	DESCRIPTION		PROFORMA AND RESTATED	PRODUCTION FACTOR	FIT 35%
1	APPLIED TO ALL BUT LINE 19	FIXED		0.000%	
2	APPLIED ONLY TO LINE 19	VARIABLE		3.839%	0.036322
3	OPERATING EXPENSE:				
4	O&M / A&G PRODUCTION RELATED				
5	WAGES & INCENTIVE - OTHER PWR 557		$ 140,926	$ -	$ -
6	WAGES & INCENTIVE - PROD O&M		337,826	-	-
7	BENEFITS - A&G 926		8,206,061	-	-
8	WORKER'S COMP - A&G 926		214,072	-	-
9	PROPERTY INSURANCE - A&G 926		2,763,777	-	-
10	TOTAL PRODUCTION O&M / A&G		11,662,663	-	-
11					
12	DEPRECIATION / AMORTIZATION:				
13	DEPRECIATION		149,765,347	-	-
14	AMORTIZATION OF TREASURY GRANTS (407.4)		-	-	-
15	AMORTIZATION (OTHER THAN REGULATORY ASSETS/LIAB)		11,818,342	-	-
16	TOTAL DEPRECIATION / AMORTIZATION		161,583,689	-	-
17					
18	OTHER TAXES:				
19	MONTANA ENERGY TAX		1,313,078	(50,414)	17,645
20	PAYROLL TAXES		2,119,540	-	-
21	TOTAL OTHER TAXES		3,432,618	(50,414)	17,645
22					
23	AMORTIZATION ON REGULATORY ASSETS (EXXLUDES POWER REG AMORT)				
24	WHITE RIVER REGULATORY ASSET		6,553,641	-	-
25	TREASURY GRANTS DEFERRAL - SNOQUALMIE		(1,381,852)	-	-
26	TREASURY GRANTS DEFERRAL - BAKER		(400,022)	-	-
27	ELECTRON UNRECOVERED COSTS		3,786,308	-	-
28	MINT FARM DEFFRAL - UE-090704		2,885,052	-	-
29	LSR PLANT DEFERRAL - UE-111048		-	-	-
30	FERNDALE PLANT DEFERRAL - UE-130617		4,520,423	-	-
31	BAKER UPGRADE PLANT DEFERRAL UE-130617		561,126	-	-
32	SNOQUALMIE UPGRADE PLANT DEFERRAL UE-130617		2,203,436	-	-
33	FERC PART 12 STUDY NON-CONSTRUCTION COSTS UE-070074		-	-	-
34	CARRYING CHARGES ON LSR PREPAID TRANSM		687,420	-	-
35	TOTAL REGULATORY ASSET ADJUSTMENT TO DECOUPLING RATE		19,415,532	-	-
36			-		
37	INCREASE (DECREASE) EXPENSE			(50,414)	17,645
38	INCREASE(DECREASE) NOI				$ 32,769
39					

Exhibit G to the Multiparty Settlement Stipulation and Agreement
Dockets UE-170033 and UG-170034
Production Adjustment

LINE NO.	DESCRIPTION	PROFORMA AND RESTATED	PRODUCTION FACTOR	FIT 35%
40				
41	RATEBASE:			
42	PRODUCTION RATE BASE:			
43	DEPRECIABLE PRODUCTION PROPERTY (INCLUDES HYDRO GRAN	$ 3,894,737,851	$ -	$ 3,894,737,851
44	PRODUCTION PROPERTY ACCUM DEPR.	(1,711,022,636)	0	(1,711,022,636)
45	NON-DEPRECIABLE PRODUCTION PROPERTY	80,139,253	0	80,139,253
46	PRODUCTION PROPERTY ACCUM AMORT.	(9,933,315)	0	(9,933,315)
47	COLSTRIP COMMON FERC ADJUSTMENT	2,908,282	0	2,908,282
48	COLSTRIP DEFERRED DEPRECIATION FERC ADJ.	858,922	0	858,922
49	ACQUISITION ADJUSTMENT	281,543,145	0	281,543,145
50	ACCUMULATED AMORTIZATION ON ACQUISTION ADJ	(113,037,112)	0	(113,037,112)
51	NET PRODUCTION PROPERTY	2,426,194,391	-	2,426,194,391
52				
53				
54	DEDUCT:			
55	LIBR. DEPREC. POST 1980 (AMA)	(513,042,624)	0	(513,042,624)
56	NOL DEFERRED TAX ASSET ATTRIBUTABLE TO PRODUCTION	48,295,905	0	48,295,905
57	TREASURY GRANTS FOR SNOQUALMIE AND BAKER		0	0
58	ACCUM AMORT OF TREASURY GRANTS FOR SNOQUALMIE AND BAKER		0	0
59	ADJUSTMENT TO RATE BASE	(464,746,719)	-	(464,746,719)
60				
61	TOTAL ADJUSTMENT TO PRODUCTION RATE BASE	1,961,447,672	0	1,961,447,672
62				
63	REGULATORY ASSETS RATE BASE (INCLUDES POWER COST REG ASSETS/LIAB):			
64	TREASURY GRANTS DEFERRAL - SNOQUALMIE	(374,252)	0	(374,252)
65	TREASURY GRANTS DEFERRAL - BAKER	(108,339)	-	(108,339)
66	BEP	0	-	0
67	WHITE RIVER REGULATORY ASSET	10,649,666	-	10,649,666
68	WESTCOAST PIPELINE CAPACITY - UE-082013 (FB ENERGY)	(88,510)	-	(88,510)
69	WESTCOAST PIPELINE CAPACITY - UE-100503 (BNP PARIBUS)	(121,339)	-	(121,339)
70	CHELAN PUD CONTRACT INITITATION	82,196,761	-	82,196,761
71	CHELAN - ROCK ISLAND SECURITY DEPOSIT	18,500,000	-	18,500,000
72	COLSTRIP 1&2 (WECo) PREPAYMENT	750,000	-	750,000
73	FERC PART 12 STUDY NON-CONSTRUCTION COSTS UE-070074	0	-	0
74	LOWER SNAKE RIVER PREPAID TRANSM PRINCIPAL	60,863,794	-	60,863,794
75	CARRYING CHARGES ON LSR PREPAID TRANSM	8,466,701	-	8,466,701
76	MINT FARM DEFFRED - UE-090704 (ENDS MAR 2025)	12,550,110	-	12,550,110
77	LOWER SNAKE RIVER PLANT DEFERRAL (ENDS APR 2016)	0	-	0
78	FERNDALE PLANT DEFERRAL (ENDS OCT 2019)	3,917,700	-	3,917,700
79	SNOQUALMIE UPGRADE PLANT DEFERRAL (ENDS OCT 2018)	596,764	-	596,764
80	BAKER UPGRADE PLANT DEFERRAL (ENDS OCT 2018)	151,972	-	151,972
81	ELECTRON UNRECOVERED PLANT COSTS	1,128,004	-	1,128,004
82	TOTAL ADJUSTMENT TO REGULATORY ASSETS RATE BASE	$ 199,079,031	$ -	$ 199,079,031
83		-		
84	TOTAL RATE BASE		$ -	

Exhibit H to the
Multiparty Settlement
Stipulation and Agreement

Exhibit H to the Multiparty Settlement Stipulation and Agreement
Dockets UE-170033 and UG-170034
Exhibit A-1 Power Cost Baseline Rates With and Without Microsoft

Row		<=Settlement=>					<=Contingent Calculation - NO MS Settlement=>				
		Test Year					Test Year				
3	Regulatory Assets (1) (Fixed)	$ 199,079,031					$ 199,079,031				
4	Transmission Rate Base (Fixed)	85,738,601					85,738,601				
5	Production Rate Base (Fixed)	1,961,447,672			Settlement Variable PF=>	0.0383940	1,961,447,672			NO MS Variable PF=>	0.0381724
6		$ 2,246,265,304				0.9616060	$ 2,246,265,304				0.9618276
7	Net of tax rate of return	6.55%			Fixed	Variable	6.55%			Fixed	Variable
8			Test Yr		Prod Cost	Prod Cost		Test Yr		Prod Cost	Prod Cost
9			$/MWh	F/V	In Decoupling	In PCA		$/MWh	F/V	In Decoupling	In PCA
9A		(I)	(II)	(III)	(IV)	(V)	(I)	(II)	(III)	(IV)	(V)
10	Regulatory Asset Recovery (on Row 3)	$ 20,061,041	$ 0.968	F	$ 20,061,041	$ -	$ 20,061,041	$ 0.989	F	$ 20,061,041	$ -
10a	Equity Adder Centralia Coal Transition PPA	4,769,481	$ 0.230	V		4,769,481	4,770,580	$ 0.235	V		4,770,580
11	Fixed Asset Recovery Other (on Row 4)	8,639,813	$ 0.417	F	8,639,813		8,639,813	$ 0.426	F	8,639,813	
12	Fixed Asset Recovery-Prod Factored (on Row 5)	197,653,573	$ 9.538	F	197,653,573		197,653,573	$ 9.745	F	197,653,573	
13	501-Steam Fuel Incl PC Reg Amort	69,962,949	$ 3.376	V		69,962,949	69,979,069	$ 3.450	V		69,979,069
14	555-Purchased power Incl PC Reg Amort	378,349,380	$ 18.257	V		378,349,380	370,094,614	$ 18.247	V		370,094,614
15	557-Other Power Exp	7,238,267	$ 0.349	F	7,238,267		7,238,267	$ 0.357	F	7,238,267	
15a	Payroll Overheads - Benefits (Inc. Worker's Comp)	8,206,061	$ 0.396	F	8,206,061		8,206,061	$ 0.405	F	8,206,061	
15b	Property Insurance	2,763,777	$ 0.133	F	2,763,777		2,763,777	$ 0.136	F	2,763,777	
15c	Montana Electric Energy Tax	1,262,663	$ 0.061	V		1,262,663	1,262,954	$ 0.062	V		1,262,954
15d	Payroll Taxes on Production Wages	2,119,540	$ 0.102	F	2,119,540		2,119,540	$ 0.104	F	2,119,540	
15e	Brokerage Fees 55700003	313,332	$ 0.015	V		313,332	313,404	$ 0.015	V		313,404
16	547-Fuel Incl PC Reg Amort	171,115,374	$ 8.257	V		171,115,374	171,056,253	$ 8.433	V		171,056,253
17	565-Wheeling Incl PC Reg Amort	108,374,278	$ 5.230	V		108,374,278	108,399,249	$ 5.344	V		108,399,249
18	Transmission Revenue 456.1	(11,639,833)	$ (0.562)	F	(11,639,833)		(11,639,833)	$ (0.574)	F	(11,639,833)	
19	Production O&M	138,209,149	$ 6.669	F	138,209,149		138,209,149	$ 6.814	F	138,209,149	
20	447-Sales to Others	(36,228,867)	$ (1.748)	V		(36,228,867)	(39,617,468)	$ (1.953)	V		(39,617,468)
21	456-Purch/Sales Non-Core Gas	(16,223,873)	$ (0.783)	V		(16,223,873)	(16,227,611)	$ (0.800)	V		(16,227,611)
22	Transmission Exp - 500KV	662,135	$ 0.032	F	662,135		662,135	$ 0.033	F	662,135	
23	Depreciation-Production (FERC 403)	161,583,689	$ 7.797	F	161,583,689		161,583,689	$ 7.966	F	161,583,689	
24	Depreciation-Transmission	3,490,805	$ 0.168	F	3,490,805		3,490,805	$ 0.172	F	3,490,805	
25	Amortization - Regulatory Assets & Liab - Non PC Only (1)	19,415,532	$ 0.937	F	19,415,532		19,415,532	$ 0.957	F	19,415,532	
26	**N/A (formerly hedging line of credit)**										
27	Subtotal & Baseline Rate	$ 1,240,098,267	$ 59.841		$ 558,403,549	$ 681,694,718	$ 1,228,434,593	$ 60.565		$ 558,403,549	$ 670,031,044
28	Revenue Sensitive Items	0.9523860	0.9523860		0.9523860	0.9523860	0.9523860	0.9523860		0.9523860	0.9523860
29	Grossed up for RSI	$ 1,302,096,279	$ 62.833		$ 586,320,619	$ 715,775,660	$ 1,289,849,486	$ 63.593		$ 586,320,619	$ 703,528,867
30	Test Year DELIVERED Load (MWH's)	20,723,206	<-- includes Firm Wholesale				20,282,959	<-- includes Firm Wholesale			
31			Total		Fixed	Variable		Total		Fixed	Variable
32	Baseline Rate Summarized										
33	BLR Net of RSI		$ 59.841		$ 26.946	$ 32.895		$ 60.565		$ 27.531	$ 33.034
34	BLR Grossed Up for RSI		$ 62.833		$ 28.293	$ 34.540		$ 63.593		$ 28.907	$ 34.686
35											
36	(1) - Amortization is picked up in Regulatory Assets and Liabilities Adjustment and White River Adjustment.										

Exhibit H to the Multiparty Settlement Stipulation and Agreement
Dockets UE-170033 and UG-170034
2017 GRC Contingent Calculation Without Microsoft Compared to 2017 GRC Settlement

Revenue Deficiency Calculation

Puget Sound Energy
REVENUE (SURPLUS) / DEFICIENCY

Row		TY / RY	17GRC Cont Calc 12MOE Sept 2016 Jan - Dec 2018	17GRC SETTLEMENT 12MOE Sept 2016 Jan - Dec 2018	(Surplus)/ Deficiency
1	Subtotal & Baseline Rate - Variable Only		$ 670,031,044	$ 681,694,718	
2	Revenue Sensitive Items ("RSI")		0.9523860	0.9523860	
3	Subtotal & Baseline Rate Variable Only Grossed-up				
4	for Revenue Sensitive Items		703,528,867	715,775,660	
5	Test Year DELIVERED Load (MWH's)		20,282,959	20,723,206	
6					
7	Gross Baseline per MWH (Line 4 / Line 5)		$ 34.686	$ 34.540	$ 0.146
8					
9	Test Year Delivered Load without Microsoft				20,282,959
10					
11	PROFORMA SCHEDULE 95 INCREASE:				$ 2,961,312

Exhibit H to the Multiparty Settlement Stipulation and Agreement
Dockets UE-170033 and UG-170034
2017 GRC Contingent Calculation Without Microsoft

PUGET SOUND ENERGY

2017 GRC Settlement Contingent Calculation Power Costs Projections - AURORA + Not in Models

Rate Year January 2018 through December 2018

Gas Price date: June 23, 2017

(dollars are in thousands)

2017 GRC Settlement Contingent Calculation - Prices at June 23, 2017

		Jan-18	Feb-18	Mar-18	Apr-18	May-18	Jun-18	Jul-18	Aug-18	Sep-18	Oct-18	Nov-18	Dec-18	17GRC Settlement Contingent Calculation
501	Coal Fuel	$ 7,667	$ 7,191	$ 7,080	$ 4,766	$ 3,346	$ 3,126	$ 6,281	$ 6,821	$ 6,270	$ 6,376	$ 6,546	$ 7,286	$ 72,756
547	Natural Gas Fuel	$ 18,744	$ 19,551	$ 15,190	$ 9,554	$ 5,587	$ 7,509	$ 13,968	$ 17,812	$ 17,030	$ 16,962	$ 17,154	$ 18,784	$ 177,845
555	Purchase & Interchang	$ 41,810	$ 33,815	$ 35,231	$ 31,390	$ 32,114	$ 27,277	$ 24,058	$ 20,307	$ 23,411	$ 27,853	$ 37,224	$ 50,292	$ 384,783
557	Other Power Supply	$ 763	$ 763	$ 763	$ 763	$ 763	$ 763	$ 763	$ 763	$ 763	$ 763	$ 763	$ 763	$ 9,156
565	Wheeling	$ 9,559	$ 9,610	$ 9,696	$ 9,545	$ 9,484	$ 9,255	$ 9,177	$ 9,228	$ 9,151	$ 9,230	$ 9,322	$ 9,444	$ 112,701
447	Secondary Sales	$ (2,322)	$ (4,583)	$ (2,081)	$ (1,699)	$ (1,467)	$ (1,878)	$ (7,801)	$ (9,017)	$ (6,563)	$ (2,709)	$ (939)	$ (133)	$ (41,190)
456	Non-Core Gas	$ (2,712)	$ (2,132)	$ (1,362)	$ (740)	$ (549)	$ (523)	$ (1,026)	$ (853)	$ (947)	$ (1,482)	$ (1,664)	$ (2,880)	$ (16,872)
	Total Power Costs	$ 73,510	$ 64,216	$ 64,517	$ 53,579	$ 49,279	$ 45,529	$ 45,420	$ 45,061	$ 49,116	$ 56,993	$ 68,405	$ 83,556	699,180
	Load in MWh	2,302,758	1,980,831	2,081,173	1,810,029	1,670,500	1,610,630	1,675,432	1,687,118	1,629,861	1,818,573	2,044,704	2,461,824	22,773,433

Settlement Power Costs	711,469.7
Diff	(12,289.9)

Exhibit H to the Multiparty Settlement Stipulation and Agreement
Dockets UE-170033 and UG-170034
2017 GRC Contingent Calculation Without Microsoft

Puget Sound Energy
Variable Cost Production Factor (NO MS)
Test Year ending September 2016
Rate Year Ending December 2018

Line No	Tariff	Description	Delivered MWh YE September 2016	Temperature Adjustment	Delivered & Normalized MWh YE September 2016	Delivered MWh YE December 2018 (F2016)
1	7	Secondary Voltage - Residential				
2	7A	Secondary Voltage - Residential Multi-Meter				
3	24	Secondary Voltage - Small General Service				
4	25	Secondary Voltage - Medium General Service				
5	26	Secondary Voltage - Large General Service				
6	29	Secondary Voltage - Irrigation Service				
7	31	Primary Voltage - General Service				
8	35	Primary Voltage - Irrigation Service				
9	43	Primary Voltage - Interruptible Schools				
10	40	Campus Service				
11	46	High Voltage - Interruptible Service				
12	49	High Voltage - General Service				
13	50-59	Lighting				
14	449-45	Retail Wheeling				
15	5	Wholesale For Resale				
16						
17	Total					
18						
19	Retail Wheeling Load					
20	Total Less Retail Wheeling (Excluding Micro		20,001,252	281,707	20,282,959	21,087,937
21						
22	Complement of Variable Production Factor					96.183%
23	Variable Production Factor					3.817%

Exhibit I to the Multiparty Settlement Stipulation and Agreement

Exhibit I to the Multiparty Settlement Stipulation and Agreement
Dockets UE-170033 and UG-170034
Parameters for the Expedited Rate Filing Authorized by Section III.H. of the Multiparty Settlement Stipulation and Agreement

The Expedited Rate Filing ("ERF") for Puget Sound Energy authorized by Section III.H. of the Multiparty Settlement Stipulation and Agreement, dated September 15, 2017, in Dockets UE-170033 and UG-170034 will be based on a Commission Basis Report ("CBR") developed for a recently completed accounting period consistent with the approach defined in WAC 480-90-257 and WAC 480-100-257.

The ERF will use only restating adjustments most recently approved by the Commission, with the following exceptions:

(i) Use of end of period rate base is acceptable.

(ii) Annualization of any revenues that occurred after the test period and annualization of the underlying costs associated with those revenues to the extent not fully included in the test year results. This is necessary to maintain proper matching of the annualized revenue and expenses.

The ERF will remove power costs, purchased gas, and gas pipeline cost recovery mechanism (and if approved Electric Cost Recovery Mechanism) related revenues, rate base and expenses leaving only transmission, distribution and administration and general costs and rate base that will be used to determine the electric and natural gas revenue requirements to be considered in the expedited rate filing.

The ERF shall maintain the rate of return established in the most recent general rate case except to update the interest rate on debt if needed.

The ERF will not include changes to rate spread or rate design from the most recently filed general rate case.