Davison Van Cleve PC
Attorneys at Law
TEL (503) 241-7242 ● FAX (503) 241-8160 ● jog@dvclaw.com
1750 S Harbor Way, Suite 450
Portland, OR 97201

June 13, 2023

Via Electronic Filing

Public Utility Commission of Oregon
Attn: Filing Center
201 High St. SE, Suite 100
Salem OR 97301

Re: In the Matter of PORTLAND GENERAL ELECTRIC CO.
Request for a General Rate Revision.
Docket No. UE 416

Dear Filing Center:

Please find enclosed the redacted version of the Opening General Rate Case (“GRC”) Testimony and Exhibits of Bradley G. Mullins (AWEC/200-204) and Lance D. Kaufman (AWEC/300-307) on behalf of the Alliance of Western Energy Consumers (“AWEC”) in the above-referenced docket.

Please note that AWEC’s Opening GRC Testimony and Exhibits contain Protected Information Subject to Modified General Protective Order No. 23-039 and Highly Confidential Information Subject to Modified Order No. 23-138. The confidential portions of AWEC’s filing have been encrypted with 7-zip software and are being transmitted electronically to the Commission and qualified persons.

Thank you for your assistance. If you have any questions, please do not hesitate to call.

Sincerely,

/s/ Jesse O. Gorsuch
Jesse O. Gorsuch

Enclosures

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that I have this day served the **Confidential and Highly Confidential Opening GRC Testimony and Exhibits of the Alliance of Western Energy Consumers** upon the parties shown below via electronic mail.

Dated at Portland, Oregon, this 13th day of June, 2023.

Sincerely,

/s/ Jesse O. Gorsuch
Jesse O. Gorsuch

CITIZENS' UTILITY BOARD OF OREGON
MICHAEL GOETZ **(C) (HC)**
WILLIAM GEHRKE **(C) (HC)**
610 SW BROADWAY STE 400
PORTLAND OR 97205
mike@oregoncub.org
will@oregoncub.org

PUBLIC UTILITY COMMISSION OF OREGON
MATTHEW MULDOON **(C)**
OPUC
P.O. BOX 1088
SALEM OR 97308
matt.muldoon@state.or.us

PUC STAFF - DEPARTMENT OF JUSTICE
STEPHANIE S. ANDRUS **(C)**
BUSINESS ACTIVITIES SECTION
1162 COURT ST NE
SALEM OR 97301
stephanie.andrus@state.or.us

PORTLAND GENERAL ELECTRIC
KIM BURTON **(C) (HC)**
PORTLAND GENERAL ELECTRIC
121 SW SALMON
PORTLAND, OR 97204
kim.burton@pgn.com

PUC STAFF - DEPARTMENT OF JUSTICE
NATASCHA SMITH **(C)**
BUSINESS ACTIVITIES SECTION
1162 COURT ST NE
SALEM OR 97301
natascha.b.smith@state.or.us

PORTLAND GENERAL ELECTRIC
JAKI FERCHLAND **(C) (HC)**
PORTLAND GENERAL ELECTRIC
121 SW SALMON – 1WTC 0306
PORTLAND, OR 97204
Jacquelyn.ferchland@pgn.com

FRED MEYER
KURT J. BOEHM **(C)**
BOEHM, KURTZ & LOWRY
36 E. SEVENTH ST., SUITE 1510
CINCINNATI, OH 45202
kboehm@bkllawfirm.com

WAL-MART
ALEX KRONAUER **(C)**
WAL-MART STORES, INC.
2608 SOUTHEAST J STREET
BENTONVILLE, AR 72716-0550
Alex.Kronauer@wal-mart.com

CALPINE ENERGY SOLUTIONS
GREGORY M. ADAMS **(C)**
RICHARDSON ADAMS, PLLC
P.O. BOX 7218
BOISE, ID 83702
greg@richardsonadams.com

CALPINE ENERGY SOLUTIONS
KEVIN HIGGINS **(C)**
ENERGY STRATEGIES
215 SOUTH STATE STREET, STE 200
SALT LAKE CITY, UT 84111
khiggins@energystrat.com

NATURAL RESOURCES DEFENSE COUNCIL
RALPH CAVANAGH **(C) (HC)**
NRDC
111 SUTTER ST., FLOOR 20
SAN FRANCISCO, CA 94104
rcavanagh@nrdc.org

NATURAL RESOURCES DEFENSE COUNCIL
CAROLINE CILEK **(C) (HC)**
GREEN ENERGY INSTITUTE
carolinecilek@lclark.edu

COMMUNITY ENERGY PROJECT
CHARITY FAIN **(C) (HC)**
COMMUNITY ENERGY PROJECT
2900 START ST., STE A
PORTLAND, OR 97214
charity@communityenergyproject.org

COMMUNITY ENERGY PROJECT
TONIA MORO **(C) (HC)**
ATTORNEY AT LAW
106 TALENT AVE, STE 6
TALENT, OR 97540
tonia@toniamoro.com

FRED MEYER
JUSTIN BIEBER **(C)**
ENERGY STRATEGIES
215 SOUTH STATE STREET, STE 200
SALT LAKE CITY, UT 84111
jbieber@energystrat.com

NEWSUN ENERGY
MARIE BARLOW **(C)**
LESLIE SCHAUER **(C)**
JACOB STEPHENS **(C)**
NEWSUN ENERGY LLC
550 NW FRANKLIN AVE, STE 408
BEND, OR 97703
mbarlow@newsunenergy.net
leslie@newsunenergy.net
jstephens@newsunenergy.net

NW ENERGY COALITION
F. DIEGO RIVAS **(C) (HC)**
NW ENERGY COALITION
1101 8TH AVE
HELENA, MT 59601
jcaviglia@parsonsbehle.com

SMALL BUSINESS UTILITY ADVOCATES
DIANE HENKELS **(C)**
SBUA
621 SW MORRISON ST., STE 1025
PORTLAND, OR 97205
diane@utilityadvocates.org

SMALL BUSINESS UTILITY ADVOCATES
GUILLERMO CASTILLO **(C)**
guillermo@utilityadvocates.org

COMMUNITY ACTION PARTNERSHIP OF OREGON
BENEDIKT SPRINGER **(C)**
2475 CENTER ST., NE
SALEM, OR 97301
benedikt@caporegon.org

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UE 416

In the Matter of	)
	)
Portland General Electric Company,	)
	)
Request for a General Rate Revision.	)
	)

OPENING GENERAL RATE CASE TESTIMONY OF

BRADLEY G. MULLINS

ON BEHALF OF THE

ALLIANCE OF WESTERN ENERGY CONSUMERS

June 13, 2023

TABLE OF CONTENTS

EXHIBIT LIST

I. INTRODUCTION AND SUMMARY

Q. PLEASE STATE YOUR NAME AND OCCUPATION.

A. My name is Bradley G. Mullins. I am the Principal Consultant of MW Analytics, a consulting practice serving and representing utility customers before state public utility commissions in the Northwest and Intermountain West. My witness qualifications were provided at **Exhibit AWEC/101**.

Q. PLEASE IDENTIFY THE PARTY ON WHOSE BEHALF YOU ARE TESTIFYING.

A. I am testifying on behalf of the Alliance of Western Energy Consumers ("AWEC"). AWEC is a non-profit trade association whose members are large energy users in the Western United States, including electric service customers of Portland General Electric Company ("PGE")

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. I discuss my initial review of PGE's proposed $337,806,933 or 14.47% increase to revenue requirement. AWEC's revenue requirement calculations are provided in **Exhibit AWEC/201**, which incorporates the recommendations of witnesses Kaufman and Walters, who are also filing Opening Testimony on behalf of AWEC in this proceeding. Throughout this text, I also present and identify relevant discovery responses of PGE , which have been attached as **Exhibit AWEC/202** in sequence.

Q. PLEASE SUMMARIZE YOUR RECOMMENDATIONS.

A. Based on AWEC's review, a rate increase is not justified, and a rate reduction is more appropriate, for PGE in this docket. As identified in Table 1, below, and in **Exhibit AWEC/201,** AWEC supports a revenue requirement reduction of $24,268,469, including the impacts of my net variable power cost testimony filed as **Exhibit AWEC/100**.

PGE is a healthy utility with loads and revenues growing with rapidity. The need PGE alleges for rate relief is its ever-inflating budget, not necessarily a need based on its actual costs and revenues. Taken as it is, the budget PGE develops lacks the proper controls and fiscal constraint necessary to rely upon it for ratemaking. Inflating a budget year after year, as PGE does, is neither a sound way to operate a business, nor a sound way to set rates. With that in mind, as well as mitigative accounting strategies for the large rate increase being sought, AWEC's revenue requirement recommendations are summarized in Table 1, below.

Table 1
AWEC Initial Revenue Requirement Adjustments
($000)

1	**Initial Filing**	**337,807**
	Impact of Adjustments:	
2	Power Costs	(170,044)
3	Cost of Capital	(11,188)
4	State Tax Flow-Through	(74,235)
5	PTC Carryforwards	(5,509)
6	Income Tax Benefit of Deferrals	(2,350)
7	Distribution Forestry Expense	(26,476)
8	Wind Maint. Outside Services	(3,218)
9	Property Insurance	(6,517)
10	Generation Outside Services	(2,809)
11	Carty Major Outage	(4,841)
12	Working Capital	(1,758)
13	Boardman Schedule 145	(5,357)
14	OATT Revenues	(10,848)
15	Faraday (Kaufman)	(16,316)
16	Beaver (Kaufman)	(9,071)
17	Fleet Fuel Cost (Kaufman)	(1,876)
18	WTC Rent Expense (Kaufman)	(9,662)
19	**Total Adjustments**	**(362,076)**
20	**Adjusted Revenue Requirement**	**(24,268)**

II. INCOME TAXES

a. State Income Tax Accounting

Q. WHAT IS YOUR RECOMMENDATION FOR STATE TAX ACCOUNTING?

A. In a revenue requirement calculation, two alternate tax accounting methods for state income taxes can be used: 1) a normalization method, as used by PGE; and 2) a flow-through method, as used by many other utilities. For state taxes, both methods are acceptable in a revenue requirement calculation. Unlike Federal income taxes, there are no requirements to use a normalization method of accounting for state income taxes. In this docket, I recommend transitioning PGE to a flow-through method of accounting for state income taxes, as doing so will mitigate the otherwise large rate increase that PGE has proposed. It will also more closely capture the actual cashflow impacts of state income tax expenditures to PGE and better reflect the cost of serving customers.

Q. WHAT IS THE DIFFERENCE BETWEEN THE TWO METHODS?

A. A normalization method of accounting is a statutory requirement for certain Federal income tax items, particularly accelerated depreciation and the investment tax credit. A normalization method spreads the impacts of income tax items, which are usually more favorable taxwise than book accounting, over the book life for the underlying tax item. Depreciation expense is accelerated for tax accounting purposes. The modified accelerated cost recovery provisions of IRC § 168, for example, might allow a depreciation deduction for utility plant over a 20-year period, whereas for book purposes, the same property might be depreciated over a 50-year period. While a utility gets a tax benefit from the shorter tax depreciable life, the normalization accounting requirements require the benefit of accelerated tax deprecation to be held in reserve and amortized over the longer 50-year period. In any given year, it is typical for the normalization method to result in ratepayers paying for more taxes in revenue requirement than the utility actually pays, with the excess applied as a reduction to rate base through FERC Account 190, accumulated deferred income taxes ("ADIT"). The excess taxes paid are called deferred taxes and often characterized as a source of zero cost financing, or an interest-free loan, and thus justified as a reduction to rate base.

A flow-through method, however, is different, and in some ways, simpler. Ratepayers pay only the amount of income taxes the utility pays. There are no deferred taxes. There are no interest-free loans. A flow-through method can be used for any income tax items that are not subject to normalization. For example, in Docket No. UM 2124, Avista sought, and was granted, permission to transition to a flow-through method of accounting for tax deductions associated with certain non-protected assets, specifically meters and certain capitalized overhead expenditures. The same goes for state tax expense. Normalization is not required for state income taxes. Accordingly, in this docket, it is within the Commission's discretion to transition PGE state taxes to a flow-through method of accounting, mitigating the large rate increase PGE has proposed.

Q. HOW DOES TRANSITIONING TO A FLOW-THROUGH METHOD MITIGATE THE RATE INCREASE?

A. The impact of transitioning to a flow-through method of accounting for state income taxes is similar to the impacts of the Avista tax accounting changes approved in Docket No. UM 2124. There are two general impacts. First, state tax expenses are restated based on current state taxes payable in the test period, excluding any provisions for deferred taxes. In response to AWEC Data Request 9, PGE confirmed that $2,653,000 of deferred income tax expense was included in the test period. Second, previously accrued and accumulated deferred state income tax (“ADSIT”) balances—*i.e.*, the interest free loans—are freed-up and available to be refunded to ratepayers. In response to AWEC Data Request 8, PGE confirmed that $143,019,000 in ADSIT had been accrued as of the test period. Thus, transitioning to a flow-through method for state income taxes will not only reduce tax expense, but will free up a material amount of ADSIT reserves from deferred taxes ratepayers formerly contributed to PGE, which can be refunded to offset the proposed rate increase.

Q. IS IT PREFERABLE TO USE A FLOW-THROUGH METHOD OF ACCOUNTING FOR STATE TAXES?

A. Yes. A flow-through method is more consistent with the actual cash-flow implications of state income taxes, and therefore, more accurately captures a utility’s revenue requirement. The effective result of normalization is that, in the long run, ratepayers consistently pay more taxes in rates than the utility pays. A utility, such as PGE, is consistently investing in new property and resource additions. As these new investments are made, deferred income taxes grow and accumulate. Under a normalization method of accounting, one would expect to pay more taxes than the utility pays in the early years of an asset’s life and less taxes than the utility pays in the later years of an asset’s life, as deferred taxes reverse. In practice, however, this reversal, and the benefit of paying less taxes than the utility in revenue requirement, never occurs. Because of ongoing property additions, ratepayers can have little expectation of an eventual situation of paying income taxes less than what the utility pays due to, for example, reversal of formerly contributed deferred taxes. From this perspective the interest-free loan from ratepayers is never really repaid—it’s continually and constantly being refinanced with higher and higher principal balances. Use of a flow-through method does away with this problem and the interest free loan altogether, and therefore, better reflects the long-term realities of how deferred state income taxes impact utility cashflows.

Q. DO OTHER UTILITIES USE A FLOW-THROUGH METHOD FOR STATE INCOME TAXES?

A. Yes. Many utilities and jurisdictions use a flow through method for state income taxes. Some states like California have specific policies requiring the use of flow-through accounting for state income taxes.[1] Thus, the flow-through method is an acceptable method for calculating revenue requirement. My experience is that utilities use the flow-through method for state taxes more often than a normalization method. In Table 2, below, I provide a list of utilities that I am aware of that use flow-through accounting for state income taxes.

Table 2
List of Utilities That Use Flow-Through Accounting for State Income Taxes[2]

Avista (Oregon & Idaho)
Intermountain Natural Gas (Idaho)
Dominion Utah (Utah)
Northwestern (Montana)
Pacific Gas & Electric
San Deigo Gas And Electric

1 *See* Public Utilities Commission of the State of California, A.14-04-014, Direct Testimony of Jonathan B. Atun, at JBA-7:10-11 (April 11, 2014) (internal citations omitted).

2 *See* Docket No. UG 153, Order No. 03-570, Attachment A, Appendix B, at 10 (Sep. 25, 2003); *See* Idaho Public Utilities Commission, Case Nos. AVU-E-10-01; AVU-G-10-01, Order No. 32070, at 8 (Sep. 21, 2010) (internal citations omitted); Idaho PUC Case No. INT-G-22-07, J. Darrington, Direct at 22:1-3 (Dec. 1, 2022); *See* Public Service Commission State of Montana Docket 2022.01.001, Annual Report of NorthWestern Energy to the Montana Public Service Commission, at 50 (2021); *See* Public Utilities Commission of the State of California, A.15-09-001, Petition for Modification of Decision 17-05-013 of Pacific Gas and Electric Company (U 39 M) to Reflect Tax Changes, Attachment B, Report of Pacific Gas and Electric Company on Revenue Requirement Revisions from the Tax Cut and Jobs Act of 2017 on the 2017 General Rate Case, at 6 (Sep. 1, 2015) (internal citations omitted); *See* Public Utilities Commission of the State of California, A.14-04-014, Direct Testimony of Jonathan B. Atun, at JBA-7:10-11 (April 11, 2014) (internal citations omitted).

Q. HOW DO YOU RECOMMEND TRANSITIONING TO THE FLOW-THROUGH METHOD IN THIS DOCKET?

A. As noted previously, a principal aspect of the change in accounting method is that previously accrued ADSIT becomes available to be refunded to ratepayers. When transitioning, the interest free loan made by ratepayers is repaid. This is similar to the refund of excess deferred income taxes that occurs when tax rates are reduced through, for instance, tax reform. These balances can be refunded over longer or shorter periods, depending on the Commission's preferences. For purposes of my analysis, I have assumed a 2-year amortization period, corresponding roughly to PGE's historical cycle of general rate case filings. Over the amortization period, the balance will be recorded to a rate base regulatory liability account.

Q. WHAT IS THE IMPACT OF THE CHANGE ON REVENUE REQUIREMENT?

A. The impacts of the change in accounting on expense and rate base can be seen in Table 3, below.

Table 3
Impact of Transitioning to Flow-Through Accounting for State Taxes

	Expense	Rate Base
Remove ADSIT		143,019,000
Record Regulatory Liability		(143,019,000)
Amortize Regulatory Liability	(71,509,500)	35,754,750
Remove Test Per. Def. SIT Expense	(2,653,000)	1,326,500
Impact	(74,162,500)	37,081,250

As seen in Table 3, when transitioning to flow-through accounting, accrued ADSIT balances are transitioned into a rate base regulatory liability account, dollar-for-dollar. The regulatory liability is subsequently amortized over a two-year period as a reduction to pre-tax expense beginning with the rate effective date of the docket. Correspondingly, the rate base of the regulatory liability balance is reduced by one-half of the amortization amount, representing the average balance over the test period. Finally, deferred state income tax expense is removed from revenue requirement. Since the average test period deferred taxes are included in ADSIT, the regulatory liability balance is also be reduced by one-half of the removed deferred state income tax expense.

Q. WHAT IS THE REVENUE REQUIREMENT IMPACT OF THESE ADJUSTMENTS?

A. These adjustments produce a $74,169,056 reduction to revenue requirement.

b. <u>Production Tax Credit Carryforwards</u>

Q. WHAT BALANCE OF PRODUCTION TAX CREDIT CARRYFORWARDS DOES PGE INCLUDE IN REVENUE REQUIREMENT?

A. PGE's filing includes $104,730,410 of production tax credit carryforwards,[3] representing production tax credits that PGE has been unable to utilize on its federal income tax returns and which PGE must carry forward to offset future tax liability. These balances are included as an increase to rate base, resulting in a $10,309,142 increase to revenue requirement. The production tax credits PGE has generated but has been unable to utilize represent a material cost associated with PGE's renewable production facilities.

Q. ARE THERE ADDITIONAL COSTS ASSOCIATED WITH THESE UNUSED PRODUCTION TAX CREDITS?

A. Yes. Since PGE has such a significant balance of production tax credit carryforwards, PGE has been unable to claim other tax benefits, such as a capital maintenance expense deduction. Typically, a utility the size of PGE will have a beneficial book tax difference for capital maintenance—capitalized costs that are depreciated for book purposes but deducted for tax

---

[3] *See* Exhibit PGE/200 workpaper 2024 "Unbundled ROO," Tab "Unbundled," Excel Row "8785."

purposes—of several hundred million, which benefits ratepayers by reducing rate base. PGE confirmed in response to AWEC Data Request 134 that it has been unable to claim a repairs deduction due to the large carryforward balances associated with production tax credits. Thus, the cost of PGE's inability to utilize production tax credits is greater than the production tax credit carryforward balances identified above.

Q. HOW DID PGE CALCULATE THE PRODUCTION TAX CREDIT CARRYFORWARD BALANCES IN REVENUE REQUIREMENT?

A. In response to AWEC Data Request 12, PGE provided the year-by-year carryforward balance calculations. In response to AWEC Data Request 133, PGE provided additional detail of the balances. PGE, however, did not provide the specific tax calculations used to derive those amounts.

Q. DID THE INFLATION REDUCTION ACT IMPACT PGE'S ABILITY TO UTILIZE PRODUCTION TAX CREDITS?

A. Yes. Under new IRC § 6418, certain tax credits, including the ITC, are now transferrable and salable. This new ability only applies to tax credits generated beginning in 2022. While the market for such credits is only beginning to be developed, it is expected that a sale of tax credits will occur at a discount.

Q. ARE RATEPAYERS BETTER OFF SELLING THE PRODUCTION TAX CREDITS FOR A DISCOUNT THAN PAYING FINANCING CHARGES ON CARRYFORWARD BALANCES?

A. Yes. PGE's pre-tax cost of capital, using PGE's filed case, was 9.84%, meaning ratepayers must pay $9.84 per year for every $100 of production tax credit carryforwards. Considering that the production tax credit carryforwards have been spanning about four years before being utilized, a sale of tax credits will avoid $39.37 in financing costs for every $100 of production tax credits generated. Thus, even if the tax credits are sold at a discount as high as 5% to 10%, it still makes overwhelming economic sense to ratepayers to sell and monetize tax credits rather than paying the 39.37% in financing charges to PGE in connection with the carryforward balances.

Q HOW MUCH PRODUCTION TAX CREDIT CARRYFORWARDS COULD BE FREED UP IN THIS CASE?

A. The sale of 2022 and 2023 credits would reduce the carryforward balance by $55,922,644 to approximately $48,807,766. This, however, would result in an offsetting increase to expense to the extent that tax credit carryforwards were sold at a discount.

Q. WHAT IS YOUR RECOMMENDATION?

A. Given the ratepayer economics of selling production tax credit carryforwards, it would be imprudent for PGE not to pursue such an alternative. Thus, I also recommend PGE immediately issue an informal request for proposal to find counterparties willing to purchase, and pursue a sale of, its production tax credits. Any discounts on the sale would appropriately be considered in the Power Cost Adjustment Mechanism. This adjustment results in a $5,504,769 reduction to revenue requirement.

c. <u>Income Tax Benefit of Deferral Balances</u>

Q. WHAT TAX ISSUE HAVE YOU IDENTIFIED WITH RESPECT TO PGE'S DEFERRAL BALANCES?

A. PGE maintains several large deferral balances, including the UM 2115 2020 Wildfire Deferral and the UM 2156 2021 Ice Storm Deferral. While these balances have material deferred income tax implications, PGE did not consider the rate base benefits of these deferred income taxes in its filing.

Q. HOW DO DEFERRALS IMPACT DEFERRED TAXES?

A. PGE was able to deduct the expenditures associated with its deferrals in the period when the expenditures were made. This provided a material benefit to PGE because it was able claim the tax benefits of those deductions without providing the corresponding tax benefits to ratepayers until the deferrals are amortized.

Q. IS IT REASONABLE FOR PGE TO RETAIN THE BENEFIT OF THOSE DEDUCTIONS?

A. No. The deductions related to deferrals, such as the Ice Storm Deferral and Wildfire Deferral, are one of the reasons that PGE has incurred such a significant carryforward balance for production tax credits. Because PGE was able to deduct those expenses, it limited the amount of production tax credits that could be utilized to offset taxable income, which ratepayers are paying for in revenue requirement. Stated differently, if PGE had not deducted the ice storm and wildfire expenses, the production tax credit balance would have been much lower than PGE is proposing in this docket. Thus, absent considering the effect of the deferrals on ADIT, PGE's overall rate base and deferred income taxes will be misstated.

Q. WHAT DO YOU RECOMMEND?

A. I recommend that the ADIT associated with deferrals be included in revenue requirement. In PGE's response to AWEC Data Request 16, Attachment A, I identified $113,579,821 in deferral balances, related to the 2022 Wildfire Emergency, the 2021 Ice Storm, and COVID-19 deferrals. On a tax-effected basis, excluding state deferred taxes, the deferred taxes from these deferrals amount to a rate base benefit of $23,851,762, and a corresponding $2,347,858 reduction to revenue requirement.

III. NON-LABOR O&M BUDGET

Q. WHAT NON-LABOR O&M EXPENSES ARE INCLUDED IN REVENUE REQUIREMENT?

A. Non-labor expenses in revenue requirement come from PGE's budget. The budget, however, presents a problem in that it is not tied to anything known and measurable. In fact, on close examination, the budget is not based on much at all, other than perhaps escalated budgets past. Oregon is a state that allows utilities to include forecast assumptions in revenue requirement. Regardless, the evidentiary standard requires that said assumptions be reasonable and prudent, characteristics that cannot be posited for the O&M budget PGE presented in its revenue requirement proposal.4 When asked to support its budgetary proposals in discovery, PGE provided iterant reference to "standard company budgeting procedure."[5] Yet, this procedure largely consists of the following: "[t]he 2024 test year forecast was [] developed by applying cost escalations to the 2023 budget."[6] Lacking any bottom-up analysis of individual cost center activities and requirements, nor reconciliation to the actual amount of funds expended in individual cost centers, such a budget procedure is no way to control costs at a sophisticated $2.5 billion utility. Given these company budgeting procedures, one may be inclined to ask the following question: if the 2024 budget was based on 2023, what was 2023 based on? In Docket UE 394, it was established that the 2023 budget was based on the 2022 budget; the 2022 budget was based on the 2021 budget; the 2021 budget was based on the 2020 budget, and so on.

---

4 *See* Order 01-777, Docket No. UE 115, dated Aug, 31, 2001, p. 9.

5 *See e.g.* PGE Response to AWEC Data Request 119

6 *Id.*

Given the customer rate pressures being faced, PGE needs to make a concerted effort to better control its costs, and it is apparent that PGE is not doing that. PGE needs to develop budgets that encourage and challenge cost center managers to reduce costs and manage program activities in an efficient manner. The Company budgeting procedures, that escalate costs year after year without any basis in actual costs incurred, do not do that and are by no means a rightful way to set a revenue requirement. In consideration of the foregoing, I propose several adjustments to PGE's non-labor O&M budget, discussed below.

a. <u>Distribution Forestry Expense</u>

Q. WHAT DISTRIBUTION FORESTRY EXPENSES DOES PGE INCLUDE IN REVENUE REQUIREMENT?

A. In FERC Account 593, PGE included budgeted outside services expenses of $53,096,279 in department "341: Forestry." In PGE/700,Bekkedahl-Jenkins/11, PGE provides a general description of these expenses and described them as routine vegetation management.

Q. HOW DOES PGE'S BUDGET FOR THIS DEPARTMENT COMPARE TO ACTUAL EXPENSES IN 2022?

A. PGE's budget compares to $27,886,411 of actual forestry expenses in 2022. Thus, PGE is requesting a $25,209,867 or 90% increase to forestry expenses in this docket.

Q. DO THESE EXPENSES INCLUDE VEGETATION MANAGEMENT INCLUDED IN PGE'S WILDFIRE MITIGATION PLAN?

A. No. This increase is also not considering the incremental forestry expenses that PGE is currently seeking for recovery associated with its wildfire mitigation plan. Those costs are being deferred and being recovered through PGE Schedule 151.

Q. DID YOU ASK PGE TO RECONCILE THE DIFFERENCE?

A. Yes. In AWEC Data Request 111, PGE was asked to explain the variance in forestry expenses. PGE explained that they were related to routine vegetation management activities and that "[t]he predominant driver of the increase in 2024 forecasted costs compared to 2022 actual costs is Forestry." In the response, PGE provided no workpapers or documents demonstrating that such a major increase is warranted and did not provide any support for its calculations. PGE also discussed routine vegetation management in confidential testimony in Exhibit PGE/700, although that testimony did not provide compelling justification for such a major increase to expense.

Q. DO THE EXPLANATIONS PGE PROVIDED IN EXHIBIT PGE/700 WARRANT SUCH A SIGNIFICANT INCREASE TO ROUTINE VEGETATION MANAGEMENT?

A. No. Without getting into confidential matters, issues surrounding shortages in qualified arborists are well documented. These shortages, however, do not justify a 90% increase to routine vegetation management expenses, particularly at a time when PGE is otherwise ramping up its wildfire-mitigation vegetation management program.

Q. WHAT IS YOUR RECOMMENDATION?

A. Given the large increase to vegetation management costs that are otherwise flowing through Schedule 151, I recommend holding PGE's routine vegetation management budget flat for the test period. This recommendation reduces revenue requirement by $26,452,868.

b. <u>Wind Maintenance Outside Services</u>

Q. WHAT WIND MAINTENANCE EXPENSES DOES PGE INCLUDE IN THE TEST PERIOD?

A. Wind maintenance expenses for the Biglow, Tucannon and Wheatridge facilities are recorded to FERC Account 553, Maintenance of generating and electric plant. In the forecast period, PGE included a total of $13,803,846 of wind maintenance expenses compared to $10,165,177 in the base period.

Q. HOW DOES PGE PERFORM WIND MAINTENANCE?

A. PGE contracts with its vendors to perform maintenance for its wind generation fleet. As PGE explained in response to AWEC Data Request 117, wind maintenance is performed under Long-Term Service Agreements ("LTSAs") with vendors. As PGE explains in that response, the amounts are pre-paid a quarter in advance and amortized to expense through FERC Account 553.

Q. WHAT IS DRIVING THE INCREASE IN MAINTENANCE EXPENSES?

A. Table 4 below provides a reconciliation between base period and forecast wind maintenance expenses.

Table 4
Non-Labor Wind Maintenance O&M Historical vs. Forecast

	2022 Actual	PGE Forecast	Delta	
LTSA	9,723,891	10,298,629	574,738	
Materials & Equipment	4,460	2,030,231	*2,025,770*	
Outside Services	435,155	1,457,425	*1,022,270*	3,063,931
Washington Sales Tax	0	17,561	*17,561*	
Travel	1,670	0	*(1,670)*	
Total	10,165,177	13,803,846	3,638,669	

As can be seen, most of the increase in wind maintenance expenses is unrelated to the LTSA. PGE is proposing a $2,025,770 increase to materials and supplies expenses, and a $1,022,270 increase to outside services expenses.

Q. DID YOU ASK ABOUT THESE INCREASES?

A. Yes. In response to AWEC Data Request 120, PGE explained the increase in the outside service costs as primarily related to work being performed at the Biglow wind facility, which was not being covered under the LTSA.

Q. ARE THE PROPOSED INCREASES IN O&M EXPENSES AT THE BIGLOW WIND APPROPRIATELY EXCLUDED FROM REVENUE REQUIREMENT?

A. Yes. In Exhibit AWEC/100, I discussed high-profile turbine failures at the Biglow facility. Some of the increases to non-labor wind O&M above may be related to correcting these failures.

Q. WHAT DO YOU RECOMMEND?

A. I recommend the Wind O&M expense, other than the proposed LTSA increases, be held flat in the forecast period. This recommendation results in a $3,215,002 reduction to revenue requirement.

c. <u>Property Insurance</u>

Q. WHAT AMOUNT OF PROPERTY INSURANCE EXPENSES WAS INCLUDED IN REVENUE REQUIREMENT?

A. PGE detailed its calculation of property insurance expenses included in O&M in response to AWEC Data Request 132, Confidential Attachment A. In the response PGE is forecasting considerable increases to its property insurance expenses.

Q. WHAT ASSUMPTIONS DID PGE MAKE?

A. PGE's proposed property insurance expenses were based on several questionable assumptions. For example, PGE assumed that the total insured value of its renewables would increase with the addition of Clearwater wind, a major project that is not included in this case. PGE also applied escalation factors, which were several times the rate of inflation without providing any support for the escalation factors assumed.

Q. HOW DO THOSE ASSUMPTIONS COMPARE TO THE MOST RECENT POLICY PREMIUMS?

A. In AWEC Data Request 174, PGE was requested to provide a comparison between the current policy premiums and the forecast policy premiums for each policy. A summary of PGE's response is provided in **Confidential Exhibit AWEC/103**.

Q. WHAT IS YOUR RECOMMENDATION FOR PROPERTY INSURANCE EXPENSES?

A. I recommend using the known and measurable 2023 property insurance premiums for revenue requirement as identified in **Confidential Exhibit AWEC/103.** The magnitude of the change PGE has proposed speaks for itself. At this time, it is not possible to conclude that such changes to the property insurance premiums are justified and the adjustments PGE applied were not supported by analysis. Further, including property insurance related to plant that is not included in this docket is also unwarranted.

d. <u>Generation Outside Services</u>

Q. WHAT IS THE ISSUE YOU HAVE IDENTIFIED WITH RESPECT TO GENERATION OUTSIDE SERVICES EXPENSES?

A. PGE has forecast large increases to outside services expenses associated with maintenance at several generation facilities. This is detailed in Table 5, below:

Table 5
Account 553 – Generation Maintenance
Outside Services Expense

	2022	2024	Delta
Beaver	1,283,948	2,761,404	1,477,456
Carty	833,479	979,348	145,869
Coyote Springs	689,829	366,824	(323,005)
General Operations and Other	1,060,349	1,517,343	456,994
Port Westward I	917,654	1,839,109	921,455
Port Westward II	326,157	322,195	(3,963)
Total	5,111,417	7,786,223	2,674,806

Given that major maintenance expenses are otherwise covered in PGE's major maintenance deferral, it is unclear why the outside service expenses were planned to increase by such a degree.

Q. DID YOU ASK PGE TO EXPLAIN THESE DIFFERENCES?

A. Yes. In AWEC Data Request 119, PGE was requested to explain the outside services expenses for Port Westward 1. In AWEC Data Request 121, PGE was requested to explain the outside services expenses for Beaver. In AWEC Data Request 122, PGE was requested to explain the outside service expenses for Coyote Springs. In AWEC Data Request 123, PGE was requested to explain the outside services expense for General Operations and Other. Similar requests for Carty and Port Westward II were not submitted given the smaller variances.

Q. HOW DID PGE RESPOND?

A. In each response, PGE provided a general explanation that maintenance is necessary to continue safely operating the facilities. This may be true, but it does not explain why such a significant increase to outside service expenses is warranted.

Q. WHAT DO YOU RECOMMEND?

A. Given that PGE was able to safely operate the facilities in 2022 with a smaller budget, I recommend holding the outside service expense budget for Account 553 flat in the test period. PGE's facilities were operating at unprecedented capacity factors in 2022, so explanations that increased expenses are necessary due to higher capacity factors is not compelling.

Q. WHAT IS THE IMPACT OF YOUR RECOMMENDATION?

A. Holding the above expenses flat for the test period results in a $6,511,641 reduction to revenue requirement.

IV. RATE BASE

a. <u>Carty Major Outage</u>

Q. PLEASE SUMMARIZE THE ISSUE YOU HAVE IDENTIFIED WITH RESPECT TO THE 2021 MAJOR OUTAGE AT CARTY?

A. As discussed in Exhibit AWEC/100, in Docket No. UE 406, PGE's 2022 Power Cost Adjustment Mechanism, parties filed Joint Testimony demonstrating that an outage at Carty was the result of imprudent actions on behalf of PGE. That proceeding settled with a $1,750,000 black box adjustment to PGE's power cost variance.

Q. DID PGE INCLUDE ANY CAPITAL IN REVENUE REQUIREMENT ASSOCIATED WITH THE 2021 OUTAGE?

A. Yes. In its response to AWEC Data Request 268, Confidential, Attachment A, PGE identified capital included in revenue requirement in connection with the 2021 outage event.

Q. HOW DO YOU RECOMMEND HANDLING THAT CAPITAL AND THE ASSOCIATED DEPRECIATION EXPENSES?

A. I recommend that the capital and associated depreciation expenses be removed from revenue requirement as imprudent.

Q. WHAT IS THE IMPACT OF YOUR RECOMMENDATION?

A. Removing the capital associated with the imprudent outage at Carty results in a $555,128 reduction to revenue requirement, including the impacts of depreciation, accumulated depreciation, and ADIT.

b. Working Capital

Q. HOW DOES PGE CALCULATE WORKING CAPITAL?

A. PGE uses the lead-lag study it prepared based on 2021 lead and lag days for operating expense accounts. The study resulted in a net revenue lag of 15.41 days or approximately 4.2% of operating expenses.

Q. WHAT ISSUE HAVE YOU IDENTIFIED WITH RESPECT TO PGE'S CALCULATION?

A. When PGE applies the lead-lag factor, it does so for all expenses, including non-operating expense accounts, such as depreciation and amortization. Depreciation and amortization are not considered in the lead-lag study. Therefore, it is not appropriate to apply the lead lag factor to depreciation and amortization expense.

Q. WHAT IS THE IMPACT OF EXCLUDING DEPRECIATION AND AMORTIZATION FROM THE WORKING CAPITAL CALCULATION?

A. Removing depreciation and amortization expenses from the working capital calculation results in a $17,840.781 reduction to rate base and a corresponding $1,756,165 reduction to revenue requirement.

V. OTHER

a. Boardman Schedule 145 Balance

Q. WHAT IS THE CURRENT BALANCE IN THE BOARDMAN SCHEDULE 145 ACCOUNT?

A. The Boardman Schedule 145 account was created to fund decommissioning expenses at Boardman, which are substantially completed. In response to AWEC Data Request 145, PGE confirmed that the current balance in the account is $12,915,344.

Q. WHAT WORK DOES PGE HAVE LEFT TO DO?

A. PGE provided the remaining decommissioning activities in response to AWEC Data Request 147. In the response, PGE identified $2,714,524 of additional decommissioning expenditures through early 2024. Thus, PGE has over-collected in Schedule 145 account by approximately $10,200,820.

Q. HOW DO YOU RECOMMEND HANDLING THE OVERCOLLECTIONS?

A. I recommend they be refunded and amortized to ratepayers over a two-year period, which has been considered in Table 1, above.

Q. WILL THERE BE OTHER ONGOING ENVIRONMENTAL COSTS AT THE BOARDMAN SITE?

A. Yes. There will be ongoing ground water monitoring and other similar activities being undertaken at the Boardman site for the foreseeable future. In response to AWEC Data Request 179, PGE identified approximately $100,000 per year in ongoing remediation expenses. These costs, however, are recurring and can appropriately be considered in base rates, similar to the ongoing expenses associated with the Trojan spent fuel facility.

b. <u>OATT Revenues</u>

Q. PLEASE PROVIDE AN OVERVIEW OF PGE'S RECENTLY COMPLETED FERC RATE CASE?

A. On October 28, 2021, PGE filed an Open Access Transmission Tariff ("OATT") rate case in FERC Docket ER22-233. On December 30, FERC approved PGE's new tariffs, suspended PGE's filing rates for a nominal period and ordered new rates to become effective January 1, 2022, subject to refund. The rate case is currently in settlement negotiations before a FERC settlement judge. In OPUC Docket No. UM 2217, the Commission approved a deferral of the incremental revenues associated with the transmission rate case.

Q. HAS THE FERC RATE CASE SINCE BEEN FINALIZED?

A. Yes. On March 22, 2023, FERC issued a Letter Order approving Portland General Electric Company's December 19, 2022 filing of an uncontested Offer of Settlement and Settlement Agreement, etc. under ER22-233.

Q. WHAT IS THE CURRENT BALANCE OF THE UM 2217 DEFERRAL?

A. In response to AWEC Data Request 74, PGE provided a calculation of the deferred OATT revenues amounts due to customers through February 2023. I have summarized that response, subject to a minor correction, in **Exhibit AWEC/204.** I have also estimated the balance due to customers through January 1, 2024, the rate effective date of this docket.

Q. WHAT CORRECTIONS DID YOU MAKE?

A. In connection with the FERC settlement, PGE was required to make a $2,519,639 refund to OATT customers as the settled transmission rates were ultimately lower than the interim rates PGE had proposed. This refund was made in March of 2023. When applying the refund to revenue amounts being deferred in Oregon, however, PGE backdated the refund to the prior periods, when the interim rates were being charged. This resulted in understating the interest accrued to cost of service customers. In my calculation, I applied the FERC refund in the month that it was made.

Also, PGE calculated the deferral based on the billed month, rather than the month accrued. This resulted in a one-month lag in PGE's calculation because customers pay their bills one month following the month when the revenues are accrued. The deferral began in January 2022, but PGE did not begin recording the deferral until February 2022, when the transmission bills for January 2022 were paid. This assumption is not accurate, however, as revenue requirement is based on accrued revenues, not billed revenues.

Q. WHAT BALANCE WILL BE DUE TO CUSTOMERS ON JANUARY 1, 2024?

A. After applying these corrections, the total amount due to ratepayers on January 1, 2024, will be approximately $19,445,390.

Q. HOW DO YOU RECOMMEND AMORTIZING THESE BALANCES?

A. I recommend a two-year amortization at the modified blended Treasury rate, plus 100 basis points.

Q WHAT IS THE IMPACT OF THIS AMORTIZATION?

A. As detailed in **Exhibit AWEC/204**, a two-year amortization results in a $10,329,270 annual reduction to PGE revenues.

VI. POWER COST ADJUSTMENT MECHANISM

Q. PLEASE SUMMARIZE PGE'S PROPOSAL TO MODIFY THE PCAM STRUCTURE AND PRINCIPLES.

A. PGE proposes to modify the Commission's existing PCAM principles, as well as modify the structure of the PCAM itself. With respect to the PCAM principles, PGE proposes to consolidate the existing five principles into four new principles, with further modifications to the goals and focus of each principle.[7] Regarding the PCAM structure, PGE proposes to:

1) Eliminate the existing -$15 million/+$30million deadbands, and replace them with a 90/10 ratepayer/Company variance sharing framework;

2) Eliminate the currently approved earnings test as applied to recovery or refund of NVPC;

3) Establish a new framework for calculating power costs associated with Reliability Contingency Events ("RCEs") called by the Company and recover costs associated with RCEs outside of the PCAM; and

4) Establish a +/- 2.5% rolling cap on annual NVPC price changes, with amounts in excess of the cap rolling over to the subsequent year.[8]

Q DO YOU SUPPORT PGE'S PROPOSAL?

A. No. The existing PCAM, which operates in conjunction with the annual AUT, was put into place over 15 years ago. It has been functioning as intended. It has been providing PGE with adequate protection against volatility in power costs, while providing PGE with the opportunity to earn a reasonable return. The Commission has repeatedly reaffirmed the PCAM design elements. Yet, seemingly in every rate case, the electric utilities insist on trying to whittle down ratepayer protections that have been put in place and for good reason. Eliminating the sharing bands and deadbands in the PCAM, for example, provide PGE with the opportunity to overearn by virtue of the PCAM, a result that is not in the public interest. If a utility is earning

[7] *See* PGE Exhibit 400, pp. 28-30.
[8] *See* PGE Exhibit 400, p, 30, ll. 8-15.

a reasonable return, providing additional rate recovery through a PCAM deferral is not reasonable. There are exceptions to earnings tests, but this is not one of them. Accordingly, I recommend the Commission reject PGE's proposal and maintain the PCAM as it has been designed.

Q. PLEASE SUMMARIZE THE PCAM AS CURRENTLY AUTHORIZED AND APPROVED BY THE COMMISSION.

A. The Commission initially established the PCAM in Proceeding No. UE 180 with the intention "to capture power cost variations that exceed those considered part of the normal business risk."[9] The PCAM "operates in conjunction with [PGE's AUT] to collect or credit the differences between actual net power costs…and the forecasted net power costs approved in the [AUT] and recovered in rates."[10] Notably, the Commission specifically declared that "normal business risk for PGE includes all of the circumstances to which it is exposed", including fuel source variability.[11]

In establishing PGE's PCAM, the Commission determined it would "apply an earnings test to determine whether [PGE] is earning an acceptable rate of return" and specified that the earning test was intended "to protect customers from paying for higher-than-expected power costs when the utility's earnings are reasonable…."[12] I would also note that the Commission continued in its discussion, finding that the earnings test "protects the Company from refunding power cost savings when it is underearning."[13]

---

9 Order No. 07-015, Proceeding No. UE 180, dated January 12, 2007, p. 26.
10 *See* Docket No. UE 264, Order No. 12-492, p. 8. (Dec. 20, 2012).
11 Order No. 07-015, Proceeding No. UE 180, dated January 12, 2007, p. 26.
12 Order No. 07-015, Proceeding No. UE 180, dated January 12, 2007, p. 26.
13 Order No. 07-015, Proceeding No. UE 180, dated January 12, 2007, p. 26.

The Commission established the deadband in recognition that "there is a range of acceptable returns on equity" and in further recognition that "an earnings review does not determine a company's actual ROE with the same accuracy as a full rate case."[14] More specifically, the Commission established the asymmetrical deadband for PGE's PCAM "to ensure that the PCAM is revenue neutral" and "so that PGE will absorb some normal variation of power costs."[15]

Finally, the Commission included a 90/10 customer/PGE sharing mechanism within the PCAM for any revenues that qualify for recovery or refund, once the earnings test and deadbands are applied. In establishing this plank of the PCAM platform, the Commission specified its expectation that the sharing mechanism [w]ould provide [PGE] with an incentive to manage its cost effectively, while sharing costs that are beyond normal business risk."[16]

Q. WHAT ARE THE SPECIFICS OF THE DEADBAND?

A. As explained by the Commission, "to ensure that the PCAM is revenue neutral" "[t]he deadband for the power cost variation…range[s] from 75 basis points ROE below the base level of NVPC included in rates, to 150 basis points ROE above." [17] These deadband specifics were subsequently modified by agreement of parties to Docket No. UE 215 to consist of a "negative annual power cost variance [of] $15 million, and the positive annual power cost variance [of] $30 million."[18] Notably, the parties agreeing to this structural modification,

---

14 Order No. 07-015, Proceeding No. UE 180, dated January 12, 2007, p. 26.
15 Order No. 07-015, Proceeding No. UE 180, dated January 12, 2007, p. 26.
16 Order No. 07-015, Proceeding No. UE 180, dated January 12, 2007, p. 27.
17 Order No. 07-015, Proceeding No. UE 180, dated January 12, 2007, p. 27.
18 Order No. 10-478, Proceeding No. UE 215, dated December 17, 2010, p. 10.

including PGE and AWEC, intended the updated PCAM to maintain consistency with the Commission original PCAM goals, including revenue neutrality.[19]

Q. WHAT ARE THE SPECIFICS OF THE SHARING MECHANISM?

A. As noted above, for any power costs above or below the deadband range, "customers will bear 90 percent of the adjustment, and PGE will bear 10 percent of the adjustment."[20] Again, the Commission opined that "[t]he 10 percent share for PGE should provide it with an incentive to manage its costs effectively, while sharing costs that are beyond normal business risk."[21]

Q. WHAT ARE THE SPECIFICS OF THE EARNINGS TEST?

A. In an effort to protect both ratepayers and PGE, the Commission "establish[ed] an earnings deadband of +/- 100 basis points around the company's allowed ROE…"[22] "If PGE is earning within +/- 100 basis points of [its] authorized rate of return, there will be no power cost adjustment for that year."[23] "[The] earnings test serves to protect customers from paying for higher-than-expected power costs when the utility's earnings are reasonable, while…protect[ing] the Company from refunding power cost savings when it is underearning."[24]

Q. DO YOU AGREE WITH PGE'S PROPOSED MODIFICATIONS TO THE PCAM?

A. No. PGE has failed to adequately demonstrate that the PCAM is in need of modification. As support for its proposed changes, PGE asserts that it "is facing a current and future state where [it] is expected to absorb power cost variability that goes far beyond the Commission's original

[19] Order No. 10-478, Proceeding No. UE 215, dated December 17, 2010, p. 10.
[20] Order No. 07-015, Proceeding No. UE 180, dated January 12, 2007, p. 27.
[21] Order No. 07-015, Proceeding No. UE 180, dated January 12, 2007, p. 27.
[22] Order No. 07-015, Proceeding No. UE 180, dated January 12, 2007, p. 27.
[23] Order No. 07-015, Proceeding No. UE 180, dated January 12, 2007, p. 27.
[24] Order No. 07-015, Proceeding No. UE 180, dated January 12, 2007, p. 27.

notions of normal utility business risk."[25] Additionally, PGE further alleges that parties participating in the AUT/PCAM process "act in their own self-interest and not consistent with a key objective of the AUT process: to accurately as possible predict power needs for the coming year and to include in rates the forecasted costs for reliably serving customers."[26]

I take issue with PGE's accusation that parties to the AUT intentionally seek to inaccurately under-forecast NPC in order to use the PCAM as an economic buffer. Presumably PGE does not include itself within the group of parties acting "in their own self-interest" despite the fact that PGE's NPC is reduced every year through adjustments identified by these "self-interested" parties and that PGE itself nearly always agrees to through settlement.

With respect to the substantive assertions made by PGE, the current PCAM structure is operating as intended and no modifications are warranted. The Commission has stated that "any adjustment under a PCAM should be limited to unusual events and capture power cost variances that exceed those considered normal business risk for the utility…."[27] As noted above, the PCAM as designed by the Commission was not intended to insulate PGE from risk associated with power cost forecasting. Indeed, the Commission opined that a well-designed PCAM should "capture power cost variances that exceed those considered normal business risk for the utility."[28] While PGE cites shifts in the energy landscape in the West since 2012, including increased renewable energy capacity, climate change, and changing wholesale market dynamics, the Company has not established that these variables impose risks that exceed those considered normal business risk for a modern electric utility. If anything, market

25 PGE 400, p. 8, ll. 4-6.
26 PGE 400, p. 8, ll. 13-16.
27 Docket No. UE 246, Order No. 12-493, at 13 (Dec. 20, 2012).
28 Docket No. UE 246, Order No. 12-493, at 13 (Dec. 20, 2012).

developments in the West, such as the Expanded Day-ahead Market and Western Resource Adequacy Program have been designed to reduce business risks, not increase them. Indeed, PGE offers no quantitative analysis at all to support its assertions.

The current PCAM framework continues to operate as designed by the Commission and should not be modified. Indeed, the modifications proposed by PGE, and in particular the proposal to recover all NVPC incurred during Reliability Contingency Events ("RCE"), unilaterally declared by PGE, outside of the PCAM structure would eviscerate the Commission's rationale behind the structure of the PCAM – the intention that "[the utility] would absorb normal variation of power costs."[29]

Q. HAS THE COMMISSION ALREADY REJECTED SIMILAR ARGUMENTS TO MODIFY THE PCAM?

A. Yes. In PacifiCorp's 2020 rate case it made substantively similar arguments to PGE's in this case and asked for similar changes to its PCAM. The Commission, however, rejected those arguments, finding that "PacifiCorp has not demonstrated a fundamental change in the risk balance between customers and the company that occurs with its power costs, and PacifiCorp has not shown that a redesign is necessary."[30] If PGE believes it is differently situated than PacifiCorp or that markets are fundamentally different than they were when the Commission issued this decision less than three years ago, it does not make any attempt to demonstrate it.

Q. HAS PGE ALSO PREVIOSULY REQUESTED RECOVERY OF SELECT NVPC OUTSIDE OF THE PCAM STRUCTURE?

A. Yes. In Docket UM 1662, PGE, along with PacifiCorp, proposed a "renewable resource tracking mechanism" that would allegedly isolate the NPC associated with RPS-eligible

---

[29] Docket No. UE 246, Order No. 12-493, at 13 (Dec. 20, 2012).
[30] Docket No. UE 374, Order No. 20-473 at 129 (Dec. 18, 2020).

resources and track them for dollar-for-dollar recovery. The utilities' proposal was based on an interpretation of the Renewable Portfolio Standard ("RPS") law, where in the utilities asserted the RPS required such rate recovery and "that the actual variable costs and benefits of these resources are not reflected in their rates … given the challenges of forecasting intermittent generation …."[31]

The Commission rejected this request in UM 1662, concluding that the RPS law did not require dollar-for-dollar recovery of power costs and that "[a]ll variable power costs, regardless of resource type, should be recovered through the operation of the Joint Utilities' respective PCAMs …. [T]hese PCAMs were designed to promote various regulatory policies and to operate in the long-term interests of the utility shareholders and ratepayers."[32] The Commission further determined that "forecast errors exist for all generation resources, and [ ] the PCAM is designed so that the errors should balance out over time. In the event of a persistent forecast error in one direction, we agree with Staff that the solution is to refine models and improve the forecasting of model inputs, not to adopt different ratemaking treatment outside the PCAM …."[33]

PGE's proposal to recover RCE-related costs outside of the PCAM ignores the Commission's prior rationale regarding recovery of all variable power costs. I recommend the Commission reject PGE's request for RCE-related cost recovery to be accomplished outside of the existing PCAM structure.

---

31 Docket No. UE 1662, Order No. 15-408, at 2 (Dec. 18, 2015).
32 Docket No. UE 1662, Order No. 15-408, at 7 (Dec. 18, 2015).
33 Docket No. UE 1662, Order No. 15-408, at 7 (Dec. 18, 2015).

Similarly, I recommend the Commission reject PGE's attempt to eliminate the deadbands within the PCAM structure. PGE has failed to demonstrate that the Commission's fundamental concern underlying this PCAM element, revenue neutrality[34], is accomplished by removing the deadbands. Moreover, and relatedly, PGE's assertion that revenue neutrality "is out of touch with" the current electric utility environment is concerning and wholly unsupported.[35]

Q. DO YOU HAVE CONCERNS REGARDING THE PROPOSED ROLLING CAP OF +/-2.5%?

A. Yes. PGE asserts that the proposed rolling cap of +/-2.5% on annual changes to NVPC would "help provide customer price stability from year-to-year."[36] However, PGE's proposals to eliminate the deadbands and the earnings test increase the potential for NVPC price instability on an annual basis. A rolling cap is not a substitute for the established deadbands and earnings test. The purpose of a rolling cap, which is used in Washington, is to reduce the number of rate changes. Deadbands and earnings tests, however, would still be necessary.

Q. PLEASE SUMMARIZE YOUR RECOMMENDATION REGARDING THE PROPOSAL PRESENTED BY PGE TO MODIFY THE DESIGN OF THE PCAM.

A. I recommend that the Commission reject PGE's proposal to modify the design of the PCAM by: 1) eliminating the deadbands; 2) eliminating the earnings test; 3) allowing recovery of RCE-related costs outside of the PCAM; and 4) authorizing a rolling cap on price changes, with an accompanying roll-over to subsequent years for additional costs.

---

34 Order No. 07-015, Proceeding No. UE 180, dated January 12, 2007, p. 26.
35 PGE 400, p. 29, l. 9.
36 PGE 400, p. 36, ll. 6-7.

Q. PLEASE SUMMARIZE THE COMMISSION'S PCAM PRINCIPLES.

A. As discussed by PGE, in 2005, the Commission established a set of four primary design criteria for a PCAM – "it must be limited to unusual events, there will be no adjustments if overall earnings are reasonable, it must be revenue neutral, and it must operate in the long-term."[37] When approving a PCAM for PacifiCorp, founded on the existing PCAM approved for PGE, the Commission formalized a fifth, "implicit[ ]" principle that "the PCAM should provide an incentive to the utility to manage its costs effectively."[38]

Q. PLEASE SUMMARIZE PGE'S PROPOSAL TO MODIFY THE PCAM PRINCIPLES ENDORSED BY THE COMMISSION.

A. PGE proposes to collapse principles 1 and 2 detailed in footnote 30 into a single guideline, and reform it to allow for dollar-for-dollar recovery of "prudently incurred power costs".[39] PGE further proposes to eliminate the Commission's focus on revenue, replacing it with a suggestion that the PCAM "incorporate reasonable pricing tools to manage long-term customer price volatility."[40]

Next, PGE avers that it recommends that "the principle regarding the balance of interests between shareholders and ratepayers remain fundamentally the same", but PGE nonetheless seeks to change the language, and therefore the potential interpretation, of the

[37] Order No. 07-015, Proceeding No. UE 180, dated January 12, 2007, p. 26. *See also* Order No. 12-493, Docket No. UE 246, dated December 20, 2012, p. 13. (the "general principles that form the basis of a well-designed PCAM [are]: (1) any adjustment under a PCAM should be limited to unusual events and capture power cost variances that exceed those considered normal business risk for the utility; (2) there should be no adjustments if the utility's overall earnings are reasonable; (3) the PCAM's application should result in revenue neutrality; (4) the PCAM should operate in the long-term to balance the interests of the utility shareholder and ratepayer; and, implicitly, (5) the PCAM should provide an inventive to the utility to manage its costs effectively.").

[38] Order No. 12-493, Docket No. UE 246, dated December 20, 2012, p. 13.

[39] PGE 400, p. 28.

[40] PGE 400, p. 28.

Commission's interest balancing principle. Finally, PGE proposes to modify the language of the cost control principle previously approved by the Commission.

Q. WHAT IS YOUR RESPONSE TO THESE PROPOSED CHANGES?

A. Modifying the principles is unnecessary, as they speak for themselves. They are just principles, which this Commission can endorse, or not. Accordingly, I recommend rejecting PGE's proposed changes to the PCAM Principles. Moreover, PGE's proposed Principle changes would undermine the prior Commissions' intentions as stated in prior Orders discussing the successful operation of the PCAM and specifically eliminate the Company's exposure to the normal business risk associated with operating an electric utility, shifting this burden wholly to ratepayers.

PGE has failed to demonstrate that the PCAM and the Commission's foundational PCAM Principles are failing to accomplish the Commission's goals. The PCAM as designed by the Commission was not intended to insulate PGE from risk associated with power cost forecasting. Indeed, the Commission opined that a well0designed PCAM should "capture power cost variances that exceed those considered normal business risk for the utility."[41] While PGE discusses the evolution of the energy landscape since 2012, including increased renewable energy capacity, and current and potential regional energy markets, PGE has not established that these variables pose risks that exceed those considered normal business risk for a modern electric utility.

[41] Order No. 12-493, Docket No. UE 246, dated December 20, 2012, p. 13.

Q. PLEASE SUMMARIZE YOUR RECOMMENDATION REGARDING THE PCAM PRINCIPLE ADJUSTMENTS PROPOSED BY PGE.

A. I recommend the Commission retain the existing PCAM Principles and reject all modifications and edits proposed by PGE.

Q. DOES THIS CONCLUDE YOUR OPENING TESTIMONY?

A. Yes.

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UE 416

In the Matters of	)
	)
PORTLAND GENERAL ELECTRIC COMPANY,	)
	)
	)
Request for a General Rate Revision.	)
	)

EXHIBIT AWEC/201

REVENUE REQUIREMENT CALCULATIONS

Electric Revenue Requirement Summary ($000)

			Revenue Requirement			Impact of Adjustments			
Line	**Adj. No.**	**Description**	Net Oper. Income	Rate Base	Rev. Req. Def. / (Suf.)	Pre-Tax Net Oper. Income	Net Oper. Income	Rate Base	Rev. Req. Def. / (Suf.)
1		**PGE Initial Filing**	**206,032**	**6,286,279**	337,807				
2		Power Costs - AWEC/100	325,708	6,286,279	167,764	161,911	119,677	-	(170,044)
		Impact of Adjustments:							
3	A1	Cost of Capital	325,708	6,286,279	156,576	-	-	-	(11,188)
4	A2	State Tax Flow-Through	380,526	6,323,360	82,341	74,163	54,817	37,081	(74,235)
5	A3	PTC Carryforwards	380,526	6,267,438	76,832	-	-	(55,923)	(5,509)
6	A4	Income Tax Benefit of Deferrals	380,526	6,243,586	74,482	-	-	(23,852)	(2,350)
7	A5	Distribution Forestry Expense	399,160	6,243,586	48,006	25,210	18,634	-	(26,476)
8	A6	Wind Maint. Outside Services	401,425	6,243,586	44,788	3,064	2,265	-	(3,218)
9	A7	Property Insurance	406,012	6,243,586	38,270	6,206	4,587	-	(6,517)
10	A8	Generation Outside Services	407,989	6,243,586	35,461	2,675	1,977	-	(2,809)
11	A9	Carty Major Outage	411,377	6,243,311	30,620	4,584	3,388	(275)	(4,841)
12	A10	Working Capital	411,377	6,225,471	28,862	-	-	(17,841)	(1,758)
13	A11	Boardman Schedule 145	415,147	6,225,471	23,506	5,100	3,770	-	(5,357)
14	A12	OATT Revenues	422,782	6,225,471	12,657	10,329	7,635	-	(10,848)
15	A13	Faraday (Kaufman)	421,230	6,037,471	(3,659)	(2,100)	(1,552)	(188,000)	(16,316)
16	A14	Beaver (Kaufman)	423,669	5,980,571	(12,730)	3,300	2,439	(56,900)	(9,071)
17	A15	Fleet Fuel Cost (Kaufman)	424,906	5,979,371	(14,606)	1,674	1,237	(1,200)	(1,876)
18	A16	WTC Rent Expense (Kaufman)	431,706	5,979,371	(24,268)	9,200	6,800	-	(9,662)
19		**Adjusted Results**	**431,706**	**5,979,371**	**(24,271)**	**305,315**	**225,675**	**(306,909)**	**(362,076)**

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UE 416

In the Matters of	)
	)
PORTLAND GENERAL ELECTRIC COMPANY,	)
	)
Request for a General Rate Revision.	)
	)

EXHIBIT AWEC/202

PGE RESPONSES TO AWEC DATA REQUESTS

March 27, 2023

To: Jesse Gorsuch
Alliance of Western Energy Consumers

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 416
PGE Response to AWEC Data Request 008
Dated March 13, 2023

Request:

Please detail the amount of accumulated deferred state income taxes in revenue requirement.

Response:

Of the $667,288,150 of accumulated deferred income taxes included in PGE's test year revenue requirement, approximately $143,019,000 is state income taxes. This does not include any state income taxes that may be considered as regulatory assets or liabilities.

March 27, 2023

To: Jesse Gorsuch
Alliance of Western Energy Consumers

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 416
PGE Response to AWEC Data Request 009
Dated March 13, 2023

Request:

Please detail the amount of deferred state income tax expense included in revenue requirement.

Response:

The amount of deferred state income tax expense net of federal benefit included in PGE's test year revenue requirement is approximately $2,653,000.

March 27, 2023

To: Jesse Gorsuch
Alliance of Western Energy Consumers

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 416
PGE Response to AWEC Data Request 012
Dated March 13, 2023

Request:

Reference workpaper “2024 Unbundled ROO,” Tab “Unbundled,” Excel Row “8785:”

a. Please provide workpapers used to forecast the $104,730,410 in production tax credit carryforwards assumed in the test period.

b. Was the referenced carryforward balance adjusted for the 2020 trading losses? If no, please explain.

c. Please provide a copy of the production tax credit carryforward statement from PGE’s 2021 Tax Return.

Response:

a. Confidential attachment 012-A provides the supporting workpaper for the carryforward of $104,730,410.
b. Yes. As discussed in PGE Exhibit 200, Section VI, pages 26-27, the carryforward balance is adjusted by $18.4 million for the 2020 trading loss event. This adjustment can be found on line 8714 of the PGE Exhibit 200 work paper, “2024 Unbundled ROO,” tab “Unbundled.”
c. Confidential attachment 012-A provides the production tax credit carryforward statement from PGE’s 2021 Tax Return.

Attachment 012-A is protected information and subject to Protective Order No. 23-039.

March 27, 2023

To: Jesse Gorsuch
Alliance of Western Energy Consumers

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 416
PGE Response to AWEC Data Request 016
Dated March 13, 2023

Request:

Please provide detail of each deferral which has been requested by PGE or approved by the Commission. At a minimum, please identify the docket where the deferral was approved and/or requested, the amortization period (if applicable), the balance as of December 31, 2022, the expected balance as of December 31, 2023, and the applicable interest rate.

Response:

PGE objects to this request on the basis that it is vague, calls for speculation and is unduly burdensome. Subject to and without waiving its objection, PGE responds as follows:

Attachment 016-A provides PGE's deferrals consistent with PGE Exhibit 1401 and includes the associated 12/31/2022 balances consistent with FERC Form 1 pages 232 and 278 (regulatory credits and debits) and to the extent practicable, forecasted amounts as of 12/31/2023. This list does not identify the final amounts approved or pending approval for amortization.

Docket No.	Description	Program	Regulatory Debits FERC Page 232 - Actuals @ 12/31/2022	Regulatory Credits FERC Page 278 - Actuals @ 12/31/2022	Account 242 - Current Reg Liability @12/31/2022	Account 229 - Accumulated provision for rate refunds @ 12/31/2022	Interest Rate	Forecasted Balance 12/31/2023
UM 1103	Intervenor Funding	Intervenor	$ 1,265,240.00	$ -			5.1300%	50,000
UM 1915	MMA (Major Maintenance Expenses)	Coyote Springs MMA	$ 1,963,328.00	$ -			0.0000%	
UM 1514	Automated DR	Automated Demand	$ 953,439.00	$ -			5.1300%	0
UM 1976	DER Test Beds	Demand Response Testbed	$ -	$ (976,638.00)			5.1300%	136,211
UM 2039	Energy Efficiency Customer Service	Sched 110 EE	$ 1.00	$ (1,407,417.00)			5.1300%	(706,938)
UM 1708	2 DR Pilots	Direct Load Control	$ 1.00	$ (480,447.00)			5.1300%	0
UM 1789	Portland Harbor	PHERA	$ 32,754,737.00	$ -			Cost of Capital & Pure	
UM 1417	Decoupling LRRA-SNA	NonRes Sch 123 SNA 2020	$ 568,759.00	$ -			5.1300%	0
UM 1938	TE Retail Charging							0
UM 2218	TE Charge							0
UM 2003	EV Charging	TE Programs (EV Charging, TE, HB-2165)	$ 791,186.00	$ (5,419,723.00)			5.1300%	0
UM 2219	Energy Affordability Act	Income Qualified Bill Discounts	$ 1,304,937.00	$ -			5.1300%	
UM 1827	DR Water Heater Pilot	Multifamily Water Heater	$ 314,594.00	$ 156,519.00			5.1300%	500,000
UM 1977	Community Solar	Community Solar	$ 3,244,961.00	$ -			5.1300%	1,559,532
UM 1482	Photovoltaic VIR	FIT	$ -	$ (3,004,636.00)			5.1300%	76,624
UM 2078	Residential Battery Storage Deferral	Battery Storage Pilot (Res)	$ 110,081.00	$ -			5.1300%	0
UM 2115	Wildfire Emergency 2020	Emergency Wildfire	$ 32,404,319.00	$ -			5.2000%	27,906,255
UM 2064	COVID-19 Costs	COVID-19	$ 21,822,549.00	$ -			5.2200%	18,405,445
UM 2037	Oregon Corporate Activities Tax	OR Commercial Activity Tax	$ (1.00)	$ (974,749.00)			5.1300%	0
UM 2046	OPUC Fee Deferral	OPUC Fee deferral	$ 2,086,942.00	$ -			5.1300%	0
UM 2156	February Ice Storm 2021	Emergency Restoration Costs	$ 77,952,617.00	$ -			5.2000%	67,268,121
UM 1417	Decoupling LRRA-SNA	NonRes Sch 123 SNA 2021	$ 6,500,079.00	$ -			5.1300%	0
UM 1301	Direct Access	Direct Access 2021	$ 15,962.00	$ -			5.1300%	0
UM 2113	Energy Storage BPSC Microgrid	Microgrid Deferral	$ 1,352,871.00	$ -			5.1300%	0
UM 2184	RFP IE and 3rd Party Consultant	Independent Evaluator	$ 246,840.00	$ -			6.8125%	
UM 1294	NVPC Costs	2021 PCAM	$ 29,276,447.00	$ -			5.1300%	14,993,732
UM 2019	Wildfire Risk Mitigation	Wildfire Mitigation	$ 28,503,868.00	$ -			5.1300%	N/A
UM 1417	Decoupling LRRA-SNA	NonRes Sch 123 SNA 2022	$ 3,642,483.00	$ -			5.1300%	$ 3,642,483.00
UM 1301	Direct Access	Direct Access 2022	$ 812,148.00	$ -			5.1300%	0
UM 1417	Decoupling LRRA-SNA	Lost Revenue Recovery 2020	$ 92,551.00	$ -			5.1300%	0
UM 1915	MMA (Major Maintenance Expenses)	KB Pipeline MMA	$ 38,422.00	$ -			0.0000%	
UM 1417	Decoupling LRRA-SNA	Lost Revenue Recovery 2021	$ 2,696,558.00	$ -			5.1300%	0
UM 1417	Decoupling LRRA-SNA	Res Sch 123 SNA 2020	$ 933,435.00	$ -			5.1300%	0
UM 1915	MMA (Major Maintenance Expenses)	Carty MMA	$ -	$ (2,661,125.00)			0.0000%	
UM 1915	MMA (Major Maintenance Expenses)	Colstrip MMA	$ -	$ (5,053,644.00)			0.0000%	
UM 1915	MMA (Major Maintenance Expenses)	PW 1 MMA	$ -	$ (3,549,217.00)			0.0000%	
UM 1915	MMA (Major Maintenance Expenses)	PW 2 LTSA	$ -	$ (4,549,361.00)			0.0000%	
UM 1988	Actual and Forecasted QF	Monet NVPC QF Deferral 2019	$ -	$ (1.00)			0.0000%	
UM 1991	R&D Income Tax Credits	Research and Development Tax Credits	$ -	$ 411,777.00			5.1300%	0
UM 1988	Actual and Forecasted QF	Monet NVPC QF Deferral 2020	$ -	$ (54,783.00)			5.1300%	
UM 1988	Actual and Forecasted QF	Monet NVPC QF Deferral 2021		$ (329,580.00)			5.1300%	
UM 1417	Decoupling LRRA-SNA	Res Sch 123 SNA 2021	$ -	$ 2.00			5.1300%	0
UM 1417	Decoupling LRRA-SNA	2022 Sch.7 Sales Norm Adj (SNA)	$ -	$ (1,367,226.00)			5.1300%	$ (1,367,226.00)
UM 2131	Metro Supportive Housing Tax	MSHS Tax	$ -	$ -			5.1300%	(9,080)
UM 1988	Actual and Forecasted QF	Monet NVPC QF Deferral 2022	$ -	$ (127,034.00)			5.1300%	
UM 1986	MCBIT				$ (974,985.37)		MBTR	(289,690)
UM 2181	Pre Filed Emergency Deferral							
UM 2190	Pre Filed Emergency Account							
UM 2217	FERC OATT Refund					$ (10,245,694.32)	MBTR	
UM 2234	Multi-Year Flex Load Plan						5.1300%	136,211
UM 2249	Community Benefits Impact Analysis Group						5.1300%	0
UM 2263	BPA RDC_PTP Deferral							

April 7, 2023

To: Jesse Gorsuch
Alliance of Western Energy Consumers

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 416
PGE Response to AWEC Data Request 074
Dated March 24, 2023

Request:

On March 22, 2023, FERC issued a Letter Order approving Portland General Electric Company's December 19, 2022 filing of an uncontested Offer of Settlement and Settlement Agreement, etc. under ER22-233:

a. Please calculate the total amount of deferred revenues due to ratepayers in UM 2217. Please provide the calculation on a monthly basis, and assuming the balance will continue to be deferred until, and commence amortization on, January 1, 2024. Please also provide workpapers supporting PGE's calculation, including interest calculations.

b. Please calculate the impact of the referenced settlement on going-forward revenue requirement in this docket and provide workpapers supporting PGE's calculation.

Response:

a. Attachment 074-A provides accrued amounts through February 2023. While amounts will continue to accrue through December 31, 2023, PGE has not yet forecasted these amounts.
b. The settlement referenced above is reflected in PGE's forecast of 2024 transmission other revenues. Attachment 074-B provides work paper support consistent with both FERC approved ER22-233 rates and PGE's other revenue forecast of $14,550,000.

April 13, 2023

To: Jesse Gorsuch
Alliance of Western Energy Consumers

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 416
PGE Response to AWEC Data Request 111
Dated March 30, 2023

Request:

Reference PGE's response to AWEC Data Request 2, FERC account "5930001: DistMaint-Overhead Lines," Cost element "2200: Outside Services": Please provide a reconciliation of the $56,342,592 amounts forecast for the referenced line items to the expense amounts incurred in the base period (calendar year 2022), including an explanation for the associated increases to the expense amounts.

Response:

PGE uses cost element (CE) 2200 for budgeting only. Actual costs are recorded using a more specific CE, denoted by the third and fourth digits of the cost element (e.g., 2201) to provide greater granularity.

Attachment 111-A compares the 2022 actuals for CE 22XXs against the 2024 forecast for CE 2200 for FERC account "5930001: DistMaint-Overhead Lines." The predominant driver of the increase in 2024 forecasted costs compared to 2022 actual costs is Forestry; please see PGE Exhibit 700, Section III.B. for more information regarding the increases to Routine Vegetation Management costs.

April 13, 2023

To: Jesse Gorsuch
Alliance of Western Energy Consumers

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 416
PGE Response to AWEC Data Request 117
Dated March 30, 2023

Request:

Reference PGE's response to AWEC Data Request 2: FERC account "5530001: OthGenMaint-Gen&ElectricPlant" includes $10,298,629 of expense assigned to cost element "5406: Amortization." Please provide an explanation for why amortization expense is appropriately included as a test period operating expense.

Response:

This amortization expense is related to PGE's wind generation Long-Term Service Agreement (LTSA) contracts. PGE maintains LTSAs with vendors for the maintenance of our wind facilities. LTSAs are typically prepaid up to a quarter in advance. The prepayment is coded to FERC 165, prepayments, and then the cost is amortized to FERC account 553, Maintenance of generating and electric equipment, over the life of the service period. When we amortize the prepaid cost to operations and maintenance, we use the cost element 5406: Amortization.

April 13, 2023

To: Jesse Gorsuch
Alliance of Western Energy Consumers

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 416
PGE Response to AWEC Data Request 119
Dated March 30, 2023

Request:

Reference PGE's response to AWEC Data Request 2, FERC account "5530001: OthGenMaint-Gen&ElectricPlant," Cost element "2200: Outside Services," O&M Summary "Portwestward I":

a. Please provide an explanation for the outside services of $1,839,109 forecast for the Port Westward I power plant and not otherwise considered in the major maintenance deferral.

b. Please provide detail of each vendor that PGE expects to perform services at the Port Westward I power plant in 2024 for services other than major maintenance, along with a description of the services that will be performed.

Response:

Regarding PGE's response to AWEC Data Request 2, PGE's generation facilities created budgets for 2023, following standard company budgeting procedure. The 2024 test year forecast was then developed by applying cost escalations to the 2023 budget. As such, the 2024 test year forecast for the above referenced amounts was based upon an escalated 2023 budget of $1,771,099, which we describe below:

a. Port Westward 1 must conduct regular annual maintenance in order to operate safely and effectively. Outside services are necessary to assist in the annual plant maintenance activities. These activities, being more regular and on-going in nature do not fit into what is considered major maintenance for purposes of PGE's major maintenance accrual account.
b. Confidential Attachment 119-A provides detail of each vendor and an explanation of the services they will be providing for 2023. We expect a similar level of activities in 2024.

Attachment 119-A provides protected information subject to General Protective Order No. 23-039.

April 13, 2023

To: Jesse Gorsuch
Alliance of Western Energy Consumers

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 416
PGE Response to AWEC Data Request 120
Dated March 30, 2023

Request:

Reference PGE's response to AWEC Data Request 2, FERC account "5530001: OthGenMaint-Gen&ElectricPlant," Cost element "2200: Outside Services," O&M Summary "Biglow":

a. Please provide an explanation for the outside services of $1,235,044 forecast for the Biglow power plant and not otherwise considered in the major maintenance deferral.

b. Please provide detail of each vendor that PGE expects to perform services at the Biglow power plant in 2024 for services other than major maintenance, along with a description of the services that will be performed.

Response:

Regarding PGE's response to AWEC Data Request 2, PGE's generation facilities created budgets for 2023, following standard company budgeting procedure. The 2024 test year forecast was then developed by applying cost escalations to the 2023 budget. As such, the 2024 test year forecast for the above referenced amounts was based upon an escalated 2023 budget of $1,189,372, which we describe below.

a. Biglow must conduct regular annual maintenance in order to operate safely and effectively. Outside services are necessary to assist in the annual plant maintenance activities. Additionally, Biglow is under a Long-Term Service Agreement (LTSA) contract with Vestas for maintenance and upkeep needs, with a portion of this expense attributed to outside services.
b. For the 2023 outside services for Biglow highlighted above, the sole vendor that PGE is using is Vestas. In compliance with the LTSA contract, part of the outside services cost is attributed to a performance-based availability bonus. The rest of outside services costs are used for Vestas labor cost that is outside of the LTSA's scope of work.

April 13, 2023

To: Jesse Gorsuch
Alliance of Western Energy Consumers

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 416
PGE Response to AWEC Data Request 121
Dated March 30, 2023

Request:

Reference PGE's response to AWEC Data Request 2, FERC account "5530001: OthGenMaint-Gen&ElectricPlant," Cost element "2200: Outside Services," O&M Summary "Beaver":

a. Please provide an explanation for the outside services of $2,761,404 forecast for the Beaver power plant and not otherwise considered in the major maintenance deferral.

b. Please provide detail of each vendor that PGE expects to perform services at the Beaver power plant in 2024 for services other than major maintenance, along with a description of the services that will be performed.

Response:

Regarding PGE's response to AWEC Data Request 2, personnel at PGE's generation facilities created budgets for 2023, following standard company budgeting procedure. The 2024 test year forecast was then developed by applying cost escalations to the 2023 budget. As such, the 2024 test year forecast for the above referenced amounts was based upon an escalated 2023 budget of $2,659,287, which we describe below.

a. Personnel at Beaver must conduct regular annual maintenance in order to operate safely and effectively. Outside services are necessary to assist in the annual plant maintenance activities. These activities, being more regular and on-going in nature do not fit into what is considered major maintenance for purposes of PGE's major maintenance accrual account.
b. Confidential Attachment 121-A provides detail of each vendor and the services they will be providing for 2023. Please note that, while not incorporated into PGE's 2024 test year forecast, PGE currently expects an increase to plant maintenance costs for 2024, as two major turbine inspections are now scheduled as opposed to the single inspection budgeted for 2023.

Attachment 121-A provides protected information subject to General Protective Order No. 23-039.

April 13, 2023

To: Jesse Gorsuch
Alliance of Western Energy Consumers

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 416
PGE Response to AWEC Data Request 122
Dated March 30, 2023

Request:

Reference PGE's response to AWEC Data Request 2, FERC account "5530001: OthGenMaint-Gen&ElectricPlant," Cost element "2200: Outside Services," O&M Summary "Coyote Springs":

a. Please provide an explanation for the outside services of the $366,824 forecast for the Coyote Springs power plant and not otherwise considered in the major maintenance deferral.

b. Please provide detail of each vendor that PGE expects to perform services at the Coyote Springs power plant in 2024 for services other than major maintenance, along with a description of the services that will be performed.

Response:

Regarding PGE's response to AWEC Data Request 2, personnel at PGE's generation facilities created budgets for 2023, following standard company budgeting procedure. The 2024 test year forecast was then developed by applying cost escalations to the 2023 budget. As such, the 2024 test year forecast for the above referenced amounts was based upon an escalated 2023 budget of $353,258, which we describe below.

a. Personnel at Coyote Springs must conduct regular annual maintenance in order to operate safely and effectively. Outside services are necessary to assist in the annual plant maintenance activities. These activities, being more regular and on-going in nature do not fit into what is considered major maintenance for purposes of PGE's major maintenance accrual account.
b. Confidential Attachment 122-A provides detail of each vendor and the services they will be providing for 2023. We expect a similar level of activities in 2024.

Attachment 122-A provides protected information subject to General Protective Order No. 23-039.

April 13, 2023

To: Jesse Gorsuch
Alliance of Western Energy Consumers

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 416
PGE Response to AWEC Data Request 123
Dated March 30, 2023

Request:

Reference PGE's response to AWEC Data Request 2, FERC account "5530001: OthGenMaint-Gen&ElectricPlant," Cost element "2200: Outside Services," O&M Summary "General Operations and Other":

a. Please provide an explanation for the outside services of the $611,942 forecast for the KB Pipeline and not otherwise considered in the major maintenance deferral.

b. Please provide detail of each vendor that PGE expects to perform services at the KB Pipeline power plant in 2024 for services other than major maintenance, along with a description of the services that will be performed.

Response:

Regarding PGE's response to AWEC Data Request 2, personnel at PGE's generation facilities created budgets for 2023, following standard company budgeting procedure. The 2024 test year forecast was then developed by applying cost escalations to the 2023 budget. To answer this data request more fully, as 2024 budgeting and vendors are not yet finalized, PGE will speak to the $589,313 forecast for 2023.

a. The annual outside services budget for the KB Pipeline is to assure that PGE, as the operator of record, maintains and operates the pipeline according to 49 Code of Federation Regulations (CFR) Part 191[1] and 49 CFR Part 192.[2] These activities, being more regular and on-going in nature do not fit into what is considered major maintenance for purposes of PGE's major maintenance accrual account.
b. Confidential Attachment 123-A provides detail of each vendor and the services they will be providing for 2023. We expect a similar level of activities in 2024.

Attachment 123-A provides protected information subject to General Protective Order No. 23-039.

[1] See 49 CFR 191: https://www.ecfr.gov/current/title-49/subtitle-B/chapter-I/subchapter-D/part-191?toc=1
[2] See 49 CFR 192: https://www.ecfr.gov/current/title-49/subtitle-B/chapter-I/subchapter-D/part-192?toc=1

April 13, 2023

To: Jesse Gorsuch
Alliance of Western Energy Consumers

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 416
PGE Response to AWEC Data Request 132
Dated March 30, 2023

Request:

Please provide workpapers supporting PGE's forecast of property insurance expense in the forecast period (2024), including details for each property insurance policy.

Response:

Confidential Attachment 132-A provides the requested information.

Attachment 132-A contains protected information and is subject to General Protective Order No. 23-039.

April 13, 2023

To: Jesse Gorsuch
Alliance of Western Energy Consumers

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 416
PGE Response to AWEC Data Request 133
Dated March 30, 2023

Request:

Reference PGE's response to AWEC Data Request 12: Please provide workpapers used to estimate the tax credit utilization in 2021, 2022, 2023, and 2024 in Attachment 12a to the referenced request.

Response:

The support provided in PGE's response to AWEC Data Request No. 012, Attachment 012-A did not properly include the usage of all federal tax credit carryforwards included in the General Business Credit. Please refer to PGE's response to OPUC Standard Data Request No. 118, Confidential Attachment 118-A for a full carryforward schedule of the federal General Business Credit.

Confidential Attachment 133-A provides the complete information regarding the carryforward, generation, and utilization of all tax credits included in the federal General Business Credit. The General Business Credit utilization is based on 75% of the federal tax liability for tax years 2021, 2022 and 2023. For years prior to 2023 this schedule considers all available credits in the General Business Credit and the proper ordering for the utilization of those credits. For purposes of estimating 2023, we ignored the impact of other tax credits, and assigned the full utilization to the PTC carryforward balance. Since 12/31/2023 is the cutoff date for rate base, there is no 2024 estimated tax credit utilization.

Attachment 133-A is protected information and subject to Protective Order 23-039.

April 13, 2023

To: Jesse Gorsuch
Alliance of Western Energy Consumers

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 416
PGE Response to AWEC Data Request 134
Dated March 30, 2023

Request:

Reference PGE's response to AWEC Data Request 15: Please explain why PGE does not claim a repairs deduction on its federal tax return.

Response:

PGE does not claim a temporary repairs deduction benefit in order to protect the utilization of the permanent tax benefit related to the Production Tax Credit.

April 13, 2023

To: Jesse Gorsuch
Alliance of Western Energy Consumers

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 416
PGE Response to AWEC Data Request 145
Dated March 30, 2023

Request:

Reference PGE's response to AWEC Data Request 67: Please confirm that PGE has a $12,915,344 balance in the Schedule 145 account as of the date of the request.

Response:

Yes. As of the request date, the Schedule 145 balance is $12,915,344.

April 13, 2023

To: Jesse Gorsuch
Alliance of Western Energy Consumers

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 416
PGE Response to AWEC Data Request 147
Dated March 30, 2023

Request:

Reference PGE's response to AWEC Data Request 67: Please provide details of all future decommissioning and remediation activities required at Boardman, including a forecast of the corresponding expenditures.

Response:

Attachment 147-A provides PGE's most recent budget for remaining decommissioning and demolition activities at Boardman. Please note, this only includes the remaining expected activities for demolition-related work. It does not include any near-term costs not specific to demolition activities or on-going activities such as PGE's on-going ground water monitoring requirements pursuant to Environmental Protection Agency Combustion Coal Residual Rules and Oregon Department of Environmental Quality Water Pollution Control Facilities permit.

	AWO	Feb-23	Mar-23	Apr-23	May-23	Jun-23	Jul-23	Aug-23	Sep-23	Oct-23	Nov-23	Dec-23
Demolition	**1000008577**											
Oversight												
PGE	1000008577	$ 18,000	$ 18,000	$ 18,000	$ 18,000	$ 18,000	$ 5,000	$ 5,000				
AECOM	1000008577	$ 70,000	$ 70,000	$ 70,000	$ 70,000	$ 70,000	$ 50,000	$ 50,000				
Resolute	1000008577	$ 5,000	$ 5,000	$ 10,000	$ 4,000	$ 2,000	$ 2,000					
Brandenburg												
Demolition	1000008577	$ 901,791	$ 901,791	$ 901,791	$ 901,791	$ 901,791						
admin bld	1000009196			$ 25,288								
scrap	1000008463	$ (820,521)	$ (820,521)	$ (820,521)	$ (820,521)	$ (820,521)						
O&M	**1000010769**											
GW/Site Maint	1000010769	$ 9,100	$ -	$ 10,000	$ 10,000	$ 10,000	$ 10,000	$ -	$ 10,000	$ 20,000	$ 10,000	$ 5,000
PGE 841	1000010769	$ 490	$ 564	$ 1,550	$ 564	$ 539	$ 515	$ 564	$ 500	$ 1,000	$ 1,000	$ 500
Evap Pond												

UE 416
PGE's Response to AWEC DR 147
Attachment A

	Jan-24	Feb-24	Mar-24	Apr-24	May-24	Jun-24	Jul-24	Aug-24	Sep-24	Oct-24	Nov-24	Dec-24
Demolition												
Oversight												
PGE			$ 2,500	$ 2,500								
AECOM			$ 25,000	$ 25,000								
Resolute												
Brandenburg												
Demolition												
admin bld												
scrap												
O&M												
GW/Site Maint			$ 10,000	$ 20,000	$ 10,000	$ 5,000			$ 10,000	$ 20,000	$ 10,000	$ 5,000
PGE 841			$ 500	$ 1,000	$ 1,000	$ 500			$ 500	$ 1,000	$ 1,000	$ 500
Evap Pond			$ 750,000	$ 750,000								

May 2, 2023

To: Jesse Gorsuch
Alliance of Western Energy Consumers

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 416
PGE Response to AWEC Data Request 174
Dated April 18, 2023

Request:

Reference PGE's response to AWEC data request 132, Attachment A: For each policy in the referenced attachment, please provide a comparison between the forecast 2024 premiums and the current premiums identified in response to Staff DR 68, Attachment H:

Response:

PGE did not provide an Attachment H in response to OPUC DR No. 68. However, the necessary data to perform a comparison between the forecasted 2024 premiums and the current premiums can be found in PGE's responses to AWEC DR No. 132, Attachment A, and OPUC DR No. 69, Attachments B, I, and H. Please see Confidential Attachment 174-A, columns G and H for the requested comparison.

Attachment 174-A contains protected information and is subject to General Protective Order No. 23-039.

May 2, 2023

To: Jesse Gorsuch
Alliance of Western Energy Consumers

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 416
PGE Response to AWEC Data Request 179
Dated April 18, 2023

Request:

Reference PGE's response to AWEC Data Request 147 Attachment A: Please provide a forecast of expenditure items that were excluded from the referenced attachment, including "costs not specific to demolition activities or on-going activities such as PGE's on-going ground water monitoring requirements pursuant to Environmental Protection Agency Combustion Coal Residual Rules and Oregon Department of Environmental Quality Water Pollution Control Facilities permit."

Response:

PGE's current expectation is that the following non-demolition items will continue to incur a cost and were not included within PGE's response to AWEC Data Request No. 147, Attachment 147-A:

1. Ash Landfill Cap Inspections
2. Invasive Weed Spraying
3. Ground Water Monitoring

The current 2024 forecast for these activities is approximately $100,000 and these costs are expected to continue over the next 30 years subject to groundwater monitoring requirements at the site. The current 30-year estimate for these activities is approximately $1 million.

June 2, 2023

To: Jesse Gorsuch
Alliance of Western Energy Consumers

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 416
PGE Response to AWEC Data Request 268
Dated May 19, 2023

Request:

Reference PGE's response to AWEC Data Request 180: Please identify all plant in service balances associated with the Carty outage identified in the referenced requires as of December 31, 2022.

Response:

Confidential Attachment 268-A provides the plant balance for the AWO associated with the referenced Carty outage.

Attachment 268-A is protected information subject to Protective Order No. 23-039.

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UE 416

In the Matters of	)
	)
PORTLAND GENERAL ELECTRIC COMPANY,	)
	)
	)
Request for a General Rate Revision.	)
	)

EXHIBIT AWEC/203

PROPERTY INSURANCE ANALYSIS

(REDACTED)

Exhibit AWEC/203 contains Protected Information Subject to Modified General Protective Order No. 23-039 and has been redacted in its entirety.

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UE 416

In the Matters of	)
	)
PORTLAND GENERAL ELECTRIC COMPANY,	)
	)
	)
Request for a General Rate Revision.	)
	)

EXHIBIT AWEC/204

OATT REVENUE DEFERRAL AND AMORTIZATION

TRC Revenue Deferral
(AWO 4%12263)

					JE Ref:
Month		2290001 Accrual / Deferral	Account? Amortization	4210010 Interest on Avg Balance	2290001 Balance
Beginning Balance:					
December	202112	-	-	-	-
January	202201	(1,060,968.02)		(3,227.11)	(1,064,195.13)
February	202202	(971,513.94)		(2,350.76)	(2,038,059.83)
March	202203	(1,020,667.97)		(3,865.06)	(3,062,592.86)
April	202204	(1,062,556.41)		(5,450.70)	(4,130,599.97)
May	202205	(755,841.87)		(6,837.92)	(4,893,279.76)
June	202206	(681,049.96)		(7,937.94)	(5,582,267.66)
July	202207	(794,005.93)		(9,068.56)	(6,385,342.15)
August	202208	(1,038,369.19)		(10,471.87)	(7,434,183.21)
September	202209	(976,193.26)		(12,015.46)	(8,422,391.93)
October	202210	(855,868.57)		(13,422.99)	(9,291,683.49)
November	202211	(941,663.88)		(14,806.48)	(10,248,153.85)
December	202212	(1,531,505.33)		(16,704.42)	(11,796,363.60)
January	202301	(780,171.70)		(69,183.49)	(12,645,718.79)
February	202302	*(757,465.87)*		(73,940.90)	(13,477,125.56)
March	202303	*1,699,960.89*		(71,685.36)	(11,848,850.03)
April	202304	*(861,931.12)*		(69,713.54)	(12,780,494.69)
May	202305	*(568,677.07)*		(74,170.15)	(13,423,341.91)
June	202306	*(492,759.09)*		(77,604.15)	(13,993,705.15)
July	202307	*(548,479.22)*		(81,000.31)	(14,623,184.68)
August	202308	*(857,420.92)*		(85,450.86)	(15,566,056.46)
September	202309	*(748,598.67)*		(90,494.73)	(16,405,149.86)
October	202310	*(660,747.08)*		(95,008.96)	(17,160,905.90)
November	202311	*(734,205.13)*		(99,507.96)	(17,994,618.99)
December	202312	*(1,344,797.29)*		(105,974.21)	(19,445,390.49)
January	202401		860,772.53	(97,134.98)	(18,681,752.94)
February	202402		860,772.53	(93,234.06)	(17,914,214.47)
March	202403		860,772.53	(89,313.22)	(17,142,755.17)
April	202404		860,772.53	(85,372.35)	(16,367,354.99)
May	202405		860,772.53	(81,411.35)	(15,587,993.81)
June	202406		860,772.53	(77,430.11)	(14,804,651.39)
July	202407		860,772.53	(73,428.54)	(14,017,307.40)
August	202408		860,772.53	(69,406.52)	(13,225,941.40)
September	202409		860,772.53	(65,363.96)	(12,430,532.83)
October	202410		860,772.53	(61,300.75)	(11,631,061.05)
November	202411		860,772.53	(57,216.78)	(10,827,505.30)
December	202412		860,772.53	(53,111.95)	(10,019,844.73)
January	202501		860,772.53	(48,986.15)	(9,208,058.35)
February	202502		860,772.53	(44,839.27)	(8,392,125.09)
March	202503		860,772.53	(40,671.22)	(7,572,023.78)
April	202504		860,772.53	(36,481.86)	(6,747,733.11)
May	202505		860,772.53	(32,271.11)	(5,919,231.70)
June	202506		860,772.53	(28,038.85)	(5,086,498.02)
July	202507		860,772.53	(23,784.97)	(4,249,510.46)
August	202508		860,772.53	(19,509.36)	(3,408,247.29)
September	202509		860,772.53	(15,211.91)	(2,562,686.67)
October	202510		860,772.53	(10,892.50)	(1,712,806.65)
November	202511		860,772.53	(6,551.03)	(858,585.15)
December	202512		860,772.53	(2,187.38)	0.00

Cost of Capital - 2022 (Jan - Apr)	7.3000%
Cost of Capital - 2022 (May - Dec)	6.8125%
Approved Blended Treas Rate (UM-1147) - 2023	1.8200%
Approved Blended Treas Rate (UM-1147) - 2023	5.1300%

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UE 416

In the Matter of	)
	)
Portland General Electric Company,	)
	)
Request for a General Rate Revision.	)
	)

OPENING GENERAL RATE CASE TESTIMONY OF

DR. LANCE D. KAUFMAN

ON BEHALF OF THE

ALLIANCE OF WESTERN ENERGY CONSUMERS

(REDACTED)

June 13, 2023

TABLE OF CONTENTS

EXHIBIT LIST

I. INTRODUCTION AND SUMMARY

Q. PLEASE STATE YOUR NAME AND OCCUPATION.

A. My name is Lance D. Kaufman. I am a consultant representing utility customers before state public utility commissions in the Northwest and Intermountain West. My witness qualification statement can be found at Exhibit AWEC/301.

Q. PLEASE IDENTIFY THE PARTY ON WHOSE BEHALF YOU ARE TESTIFYING.

A. I am testifying on behalf of the Alliance of Western Energy Consumers ("AWEC"). AWEC is a non-profit trade association whose members are large energy users in the Western United States, including customers receiving electric services from Portland General Electric Company ("PGE" or "Company).

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. I provide testimony on the following items:

- Cost of service, rate spread, and rate design;
- Prudence of PGE's investment in the Faraday Resiliency and Repowering Project ("Faraday Project"), and the Beaver Emissions Reduction Program;
- Impacts of PGE's fleet electrification on test year fuel costs; and
- Affiliated interest charges associated with PGE's rental of the World Trade Center ("WTC").

Q. PLEASE SUMMARIZE YOUR RECOMMENDATIONS.

A. I make the following recommendations:

- Update the marginal cost study to reflect the allocation of consumer costs described in this testimony,
- Update the generation marginal cost study to:

- Modify the cost of characteristics of batteries to be consistent with PGE's 2023 IRP:
  - Remove wheeling costs from battery calculations; and
  - Remove capacity value from the cost of wind energy.
- Find the Faraday Project investment decision to be imprudent and to exclude return on this investment, but to allow recovery of long-term cost of debt for the project.
- Find the management of the Faraday Project was imprudent and exclude return of and return on all costs exceeding the 2019 cost forecast.
- Find the investment in the Beaver Project was imprudent and exclude return on and return of the project costs.
  - Alternately, find the investment was made ahead of need, and is only necessary for two of six units. Exclude all project costs in this case but allow PGE to request inclusion of project costs for two units in future rate cases.
- Reduce Fuel Cost to reflect 2021 fuel expense adjusted for PGE's fleet electrification.
- Modify the affiliated interest transaction price used to determine WTC rent expense.

II. MARGINAL COST STUDY

Q. PLEASE SUMMARIZE YOUR ADJUSTMENTS TO PGE'S MARGINAL COST MODEL.

A. I make two recommendations for PGE's marginal cost model.

1. I recommend the consumer marginal cost model be updated to be consistent with PGE's cost unbundling model. I understand that PGE intends to submit such updates in its reply testimony.

2. I recommend modifications be made to the marginal cost of generation model to reflect PGE's 2023 Integrated Resource Plan ("IRP"), to remove wheeling costs from the cost of battery facilities, and to remove capacity value from the cost of energy.

a. Consumer Cost Model Is Not Consistent with Cost Unbundling Model

Q. PLEASE DESCRIBE YOUR ADJUSTMENTS TO PGE'S CUSTOMER MARGINAL COST MODEL.

A. PGE's consumer marginal cost model only uses allocation factors to directly allocate certain unbundled consumer costs to rate schedules. Some consumer costs that could be allocated in the consumer model are either not allocated or are allocated in the metering cost model rather than the consumer cost model. As a result, an excessively large share of consumer costs are not directly allocated. These costs are instead allocated to rate schedules proportionately to the few directly allocated costs. PGE has admitted in discovery that the metering and consumer cost models should be modeled consistently with the unbundling model. I understand that PGE intends to update its metering and consumer cost models as part of reply testimony.[1] I recommend that the costs and departments identified in this testimony be in the consumer cost model consistently with PGE's filed cost unbundling study.

Q. WHAT COSTS DO YOU RECOMMEND BE ALLOCATED IN THE CONSUMER MODEL?

A. I recommend the following costs be modeled as consumer costs and allocated consistent with PGE's responses to AWEC DRs 245, 286, and 287:

- Account 9030001 Department 401: Business Customer Contact
- Account 9030001 Department 404: Customer Services Ops Admin
- Account 9030001 Department 432: Customer Contact Operations
- Account 9030001 Department 472: OPS Performance Solutions
- Account 9050001 Department 555: VP, Customer Solutions

[1] May 26th discussion with PGE Staff Casey Manley.

- Account 9080001 Department 567: Customer Digital Channels

I recommend costs for the following departments that have been unbundled to consumers be modeled as consumer costs and allocated consistent with PGE's response to AWEC DR 247:

- 532: Product Portfolio Management
- 533: Product Development
- 538: Residential Marketing Project Office:
- 544: Growth and Commercialization
- 547: Commercial Energy Offerings
- 542: Transportation Electrification

Q. WHAT ARE THE IMPACTS OF YOUR RECOMMENDATION ON CONSUMER COST ALLOCATIONS?

A. I have not calculated the cost impacts of these allocation changes because PGE has indicated that PGE will present the revisions in reply testimony.

b. <u>Generation Cost Model Does Not Account for Capacity Contributions</u>

Q. WHAT IS THE GENERATION COST MODEL?

A. The Generation Cost Model partitions unbundled generation cost into demand and energy components and allocates these components to rate schedules based on demand and energy allocators.

Q. WHAT RECOMMENDATIONS DO YOU HAVE FOR THE GENERATION COST MODEL?

A. I have the following recommendations for the generation cost model:

- Modify the cost of characteristics of batteries to be consistent with PGE's 2023 IRP:
  - Reduce Battery Effective Load Carrying Contribution ("ELCC") from 83% to 57%;
  - Modify battery salvage cost from -5% to -0.5%;
  - Increase overnight capital cost from $1,195/kW to $1,214/kW;
- Remove wheeling costs from battery calculations; and

- Remove capacity value from the cost of wind energy.

Q. HOW DO THE BATTERY CHARACTERISTICS IN PGE'S GENERATION COST MODEL COMPARE TO PGE'S 2023 IRP?

A. The table below compares the values used in the generation cost model with the values sued in the IRP.

Table LK-1: Comparison of Battery Inputs

Row	Input	Marginal Cost Study	CEP/IRP
25	ELCC	83%	57%
26	Availability Factor	97%	97%
27	Economic Life	20	20
28	Salvage Value	-5%	-0.5%
29	Overnight Capital (2024 $/kW)	$1,195	$1,214

Q. WHAT IS ELCC?

A. ELCC is the measure that PGE uses in its IRP to determine the contribution of a new resource to meeting PGE's capacity needs.[2] If PGE has a capacity need of 100 MW, PGE would require 200 MW nameplate capacity of a resource with a 50% ELCC to meet this need.

Q. HOW IS ELCC RELEVANT TO PGE'S GENERATION COST MODEL?

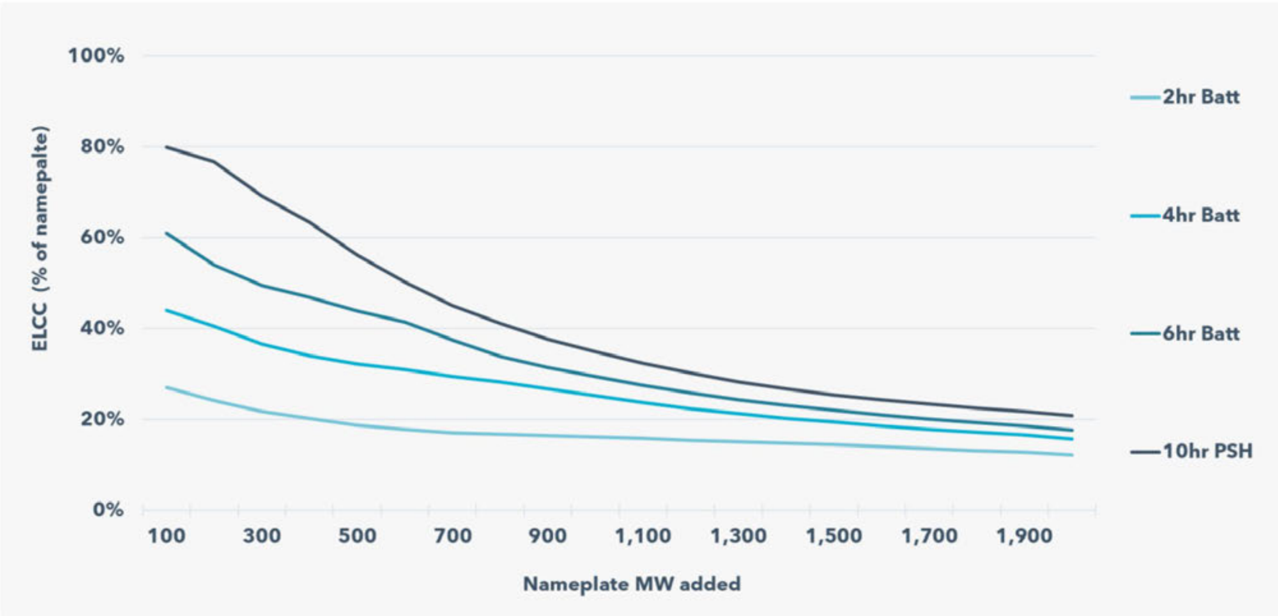
A. PGE uses ELCC in its generation cost model to calculate the amount of demand that a battery facility serves. PGE first calculates the real levelized annual cost of a 50 MW 4-hour battery storage facility. PGE then divides this cost by the kW of capacity that this facility serves.

Q. WHAT IS THE RELATIONSHIP BETWEEN ELCC AND INCREMENTAL BATTERY ADDITIONS?

A. The figure below shows that the Winter ELCC for 4-hour batteries rapidly declines with larger MW additions.

[2] PGE 2023 IRP Appendix J.

Figure LK-1: PGE 2023 IRP Figure 148 Winter Storage ELCC



Q. WHY DOES PGE USE AN ELCC OF 83%?

A. PGE uses an ELCC of 83% because PGE is modeling the characteristics of 50 MW of incremental battery additions.[3]

Q. WHY DO YOU RECOMMEND REDUCING PGE'S BATTERY ELCC FROM 83% TO 57%?

A. The use of an 83% ELCC is not a realistic representation of PGE's long term marginal cost of generation. PGE's generation cost model is intended to be a long-term marginal cost model. According to the National Association of Regulatory Utility Commissioners, "[i]n economic terms, long-run marginal cost refers to the cost of serving a change in customer usage when all factors of production (i.e., capital facilities, fuel stock, personnel, etc.) can be varied to achieve least-cost production."[4] The best source for evaluating the least cost production is PGE's IRP.

3 PGE Response to AWEC Data Request 249 part c.

4 National Association of Regulatory Utility Commissioners, Electric Utility Cost Allocation Manual, at 109 (Jan. 1992).

PGE's IRP shows that least cost production will require at least 623 MW of 4-hour battery storage.[5] An incremental selection of 623 MW of batteries results in an ELCC of 57%.[6] This level of battery additions is supported when PGE's existing capacity resources such as Port Westward and Carty are assumed to be fixed. If all of PGE's existing factors of production could be varied, PGE's total selection of battery storage would likely greatly exceed 600 MW, and thus the ELCC of batteries would likely be much lower than 57%.

Q. WHAT IS THE IMPACT OF REDUCING BATTERY ELCC TO 57%?

A. Reducing the Battery ELCC from 83 to 57 percent increases the cost of capacity from $138.52 per kW-year to $201.70 per kW-year.

Q. WHY DO YOU RECOMMEND USING THE IRP VALUES FOR NET SALVAGE RATHER THAN PGE'S PROPOSED VALUES?

A. PGE's proposed battery net salvage value of -5 percent appears to have been an error that PGE intends to correct in reply testimony.[7]

Q. WHAT IS THE IMPACT OF CHANGING BATTERY NET SALVAGE FROM -5% TO -0.5%?

A. This reduces demand cost from $201.70 per kW-year to $199.92 per kW-year.

Q. WHY DO YOU RECOMMEND REMOVING WHEELING COSTS FROM THE COST OF BATTERY CAPACITY?

A. The inclusion of wheeling costs appears to have been an error that PGE intends to correct in reply testimony.[8]

Q. WHAT IS THE IMPACT OF REMOVING WHEELING COSTS?

A. This increases demand cost from $199.92 per kW-year to $211.95 per kW-year.

---

5 PGE Response to AWEC Data Request 252 part b.
6 PGE Response to AWEC Data Request 252 part b.
7 PGE Response to AWEC Data Request 249 part a.
8 PGE Response to AWEC Data Request 249 part b.

Q. WHY DO YOU RECOMMEND USING THE IRP VALUES FOR CAPITAL COSTS RATHER THAN PGE'S PROPOSED VALUES?

A. PGE's proposed battery capital cost value of $1,195 appears to have been sourced from a draft version of PGE's 2013 IRP.[9] The corresponding value of $1,214 from PGE's final IRP is a more up-to-date value.

Q. WHAT IS THE IMPACT OF CHANGING BATTERY CAPITAL COST FROM $1,195 TO $1,214?

A. This increases demand cost from $211.95 per kW-year to $214.24 per kW-year.

Q. WHY DO YOU RECOMMEND REMOVING CAPACITY VALUE FROM THE COST OF ENERGY?

A. The function of the generation cost model is to allocate capacity costs using a capacity allocation factor and to allocate energy costs using an energy allocation factor. PGE has historically accomplished this by first calculating the levelized cost of energy for a combined cycle combustion turbine ("CCCT") in terms of cost per MWh, then reducing this amount to account for the capacity value of the CCCT. PGE's new generation model uses a wind facility rather than a CCCT to calculate the cost of energy. However, PGE's revised model fails to remove the capacity value of wind. As a result, costs that are allocated as "energy" costs contain both energy and capacity costs. It is inappropriate to use the energy allocation factor to allocate these costs.

PGE admits that its failure to remove capacity from the cost of wind energy results in an inaccurate model.[10] This inaccuracy systematically inflates the cost of energy and is unfair to customer groups with relatively high energy use and low-capacity use.

[9] PGE Response to AWEC Data Request 249 part a.
[10] PGE Response to AWEC Data Request 288.

Q. HOW DO YOU PROPOSE REMOVING CAPACITY VALUE FROM THE COST OF WIND ENERGY?

A. I recommend converting wind capacity value into a $ per MWh figure and subtracting this amount from the total cost of wind energy. Capacity as $ per MWh is equal to the annual value capacity produced by a wind facility[11] divided by the annual energy produced by that facility.[12] This is the same method used by PGE in prior rate cases.

Q. WHAT IS THE IMPACT OF REMOVING CAPACITY FROM WIND ENERGY COSTS?

A. This reduces the cost of energy from $56.24 /MWh to $39.13 /MWh.[13]

Q. DO THE CHANGES THAT YOU HAVE SUGGESTED RESULT IN AN ACCURAGE GENERATION MARGINAL COST MODEL?

A. These changes provide incremental changes that are accurate and appropriate for PGE's transition to a low carbon emissions utility. It may be necessary in future rate cases to model lower capacity contributions from storage to account for the difficulty that PGE faces in achieving higher levels of emissions reductions.

Q. HOW DO YOUR RECOMMENDATIONS AFFECT THE ALLOCATION OF GENERATION COSTS TO RATE SCHEDULES?

A. The table below compares the allocation of generation costs under PGE's proposal and my recommendations.

[11] PGE's model uses a Montana wind facility to represent energy costs. Annual capacity value is calculated as nameplate capacity times Montana wind ELCC (31%).
[12] Annual generation is nameplate capacity times capacity factor (44.3%) time hours per year (8,760).
[13] Exhibit AWEC 303.

Table LK-2 Generation Cost Allocation Comparison

	Generation Allocation ($000)		
	PGE	AWEC	Change
Schedule 7	$644,683	$675,159	4.7%
Schedule 15	$805	$777	-3.5%
Schedule 32	$114,216	$113,356	-0.8%
Schedule 38	$1,966	$1,896	-3.6%
Schedule 47	$1,694	$1,719	1.5%
Schedule 49	$5,269	$5,448	3.4%
Schedule 83	$209,402	$205,295	-2.0%
Schedule 85	$193,105	$185,151	-4.1%
Schedule 89/75	$86,547	$81,473	-5.9%
Schedule 90	$202,162	$189,815	-6.1%
Schedule 91/95	$2,412	$2,328	-3.5%
Schedule 92	$180	$168	-6.8%

III. RATE DESIGN

Q. PLEASE DESCRIBE YOUR ADJUSTMENTS TO PGE'S RATE DESIGN.

A. At this time I support PGE's recommended rate design, but will review any changes recommended by other parties and may respond to those changes in rebuttal testimony. Regardless, I recommend that the inputs to PGE's model be updated to reflect the marginal cost changes identified in the previous section.

IV. FARADAY PROJECT

i. PGE's Decision to Repower Faraday Was Imprudent.

Q. PLEASE SUMMARIZE YOUR ARGUMENT.

A. PGE is requesting rate recovery for a $188 million investment in the Faraday Powerhouse to address flood and seismic concerns. This investment provides negligible energy and capacity benefits and was not required of PGE by any rules or regulations. PGE's choice to rebuild the

Faraday Powerhouse was an imprudent investment decision. PGE misrepresents the potential impacts of flood and seismic damage on PGE's Federal Energy Regulatory Commission ("FERC") license. As a result, PGE incorrectly dismissed the most economic alternatives. Furthermore, of the two alternatives that PGE did consider; PGE chose the less economic alternative. PGE failed to inform its Board that its analysis showed the project to be uneconomic. PGE should have continued operating the Faraday without any modifications or with minimal modifications necessary to address certain structural issues.

Q. PLEASE PROVIDE A BRIEF BACKGROUND ON THE FARADAY POWERHOUSE.

A: The original 1907 Faraday Powerhouse consisted of generating units 1 through 5 with a total of 16 MW of capacity. "Faraday is one of PGE's multiple hydro facilities located on the Clackamas and Willamette Rivers that make up the West Side Hydro facilities. West Side Hydro includes eight powerhouses and 28 turbine generators totaling a FERC-authorized installed capacity of 178 MW. West Side Hydro includes all hydroelectric projects on the Willamette and Clackamas Rivers. Within West Side Hydro, the Clackamas River Project includes all facilities on the Clackamas River, including Oak Grove, North Fork, Faraday, and River Mill."[14] The Generating plants, including Faraday, are all operated under a single FERC license, referred to as the "Clackamas River Project." The original license was issued January 18, 1957, with a term expiring on August 31, 2006.[15] The license was amended on April 23, 1965 to include Faraday.[16] In 2010, PGE renewed its FERC license to continue operating the Clackamas River Project for an additional 45 years.[17]

[14] UE 416 / PGE / 800 Jenkins – Bekkedahl / 18:21-19:5.
[15] 133 FERC P62,281, at PP 2 (Dec. 21, 2010) (internal citations omitted).
[16] *Id.* (internal citations omitted).
[17] UE 416 / PGE / 800 Jenkins – Bekkedahl / 22:15-16.

Q. PLEASE PROVIDE A BRIEF BACKGROUND ON THE FARADAY REPOWERING PROJECT.

A. The Faraday Repowering Project replaced the original 16 MW Faraday Units 1 through 5 with a new powerhouse, referred to as Units 7 and 8. Units 7 and 8 were placed in service in 2023 after substantial delays and have a combined capacity of 18.8 MW. Faraday Unit 6 was "in good condition and no upgrade was necessary."[18]

Q. WHAT REASONING DOES PGE PROVIDE IN SUPPORT OF THE FARADAY REPOWERING PROJECT?

A. According to PGE, the Faraday Powerhouse was seismically unfit and subject to flooding due to the "low flood wall which exposed the generator deck."[19] Further, "[t]he facility and plant equipment had outlived its original design life, did not meet current structural code, and required increasing O&M costs."[20] Additionally, PGE states that in accordance with "federal law, FERC regulations, and its License," the Company was required to "repair, restore and mitigate safety risks."[21]

Q. WHAT WAS THE TOTAL COST AND CAPACITY INCREASE OF THE FARADAY REPOWERING PROJECT?

A. The total project cost is $147.8 million.[22] Faraday units 7 and 8 provided an additional 2.8 MW of capacity. PGE is requesting $188 million in rate base for this project.

Q. WHAT CONCERNS DO YOU HAVE REGARDING PGE'S DECISION TO INVEST IN THE FARADAY PROJECT?

A. The Faraday Project was not an economical project, and the project was not required for compliance with any specific requirements. PGE's economic modeling was subject to flaws

---

18 UE 416 / PGE / 800 Jenkins – Bekkedahl / 16:9.
19 UE 416 / PGE / 800 Jenkins – Bekkedahl / 25:16-17.
20 UE 416 / PGE / 800 Jenkins – Bekkedahl / 16:13-14.
21 UE 416 / PGE / 800 Jenkins – Bekkedahl / 16:14-16.
22 UE 416 / PGE / 800 Jenkins – Bekkedahl / 47:7.

that greatly overestimated the value of the project. Furthermore, despite these flaws, PGE's own economic analysis of the project did not support the project as a least-cost project. PGE did not notify its Board that the project was not economic when it requested project approval.[23]

Q. WHAT CONCERNS DO YOU HAVE WITH PGE'S ECONOMIC MODELING OF THE FARADAY PROJECT?

A. I have four concerns with PGE's modeling of the Faraday Project. First, PGE's model shows that the investment is uneconomic relative to the alternative evaluated. Second, PGE grossly overestimated the amount of incremental energy associated with the project. Third, the model double counts capacity benefits by using both PGE's Public Utility Regulatory Policies Act ("PURPA") avoided cost rate, which includes capacity value in years where PGE has a capacity need, and a direct capacity benefit in all years regardless of need. Fourth, PGE did not consider alternatives that involved minimal upgrades.

Q. WHAT WAS THE OUTCOME OF PGE'S ECONOMIC MODELING OF THE PROJECT?

A. PGE found that the Faraday Project had a negative net present value of [redacted].[24] This means that the Faraday Project had more costs than benefits.

Q. HOW DID PGE GROSSLY OVERESTIMATE THE AMOUNT OF INCREMENTAL ENERGY ASSOCIATED WITH THE PROJECT?

A. PGE's economic model assumed that the project resulted in 32,490 MWh more generation, on average, than existing facilities. However, this was a faulty analysis that relied on comparing 5 years with major plant outages when calculating generation of existing facilities with generation resulting from engineering modeling of 15 years of stream flows assuming no

23 PGE Response to AWEC Data Request 242 part a.
24 PGE Response to AWEC Data Request 59, Confidential Attachment A NPV Analysis - 2019.xlsm.

material plant outages.[25] PGE's net power cost forecasting for 2023 provides a more realistic assessment of incremental energy using data that was available to PGE in 2019.[26] The actual incremental energy after accounting for outages was only [redacted] MWh per year.

Q. WHAT IMPACT DOES CORRECTING FOR INCREMENTAL ENERGY HAVE ON THE ECONOMIC ANALYSIS?

A. When PGE's cost benefit model for the Faraday Project is updated with an accurate and known incremental energy forecast, the net present value of the project reduces from [redacted] to [redacted].

Q. HOW DOES PGE'S MODEL DOUBLE COUNT CAPACITY VALUE?

A. PGE used the filed standard baseload renewable avoided cost rate to value the incremental energy of the Faraday Project. PGE's avoided cost energy rate includes capacity values in years where PGE is capacity deficient. PGE also directly added to the benefit of the project in every year of its operation by multiplying the cost of capacity by the incremental capacity of the project regardless of whether PGE faced a capacity shortfall. PGE admits that this is double counting the value of capacity.[27]

Q. HOW DO YOU REMEDY PGE'S DOUBLE COUNTING OF CAPACITY?

A. I remove the direct capacity adder and maintain the use of PGE's standard avoided cost rate. This approach places PGE on equal footing with other small renewable generators. This change reduces the net present value of the project from [redacted] to [redacted].[28]

---

25 Exhibit PGE / 807C.
26 Exhibit AWEC 304 #_2024GRCFaradayModeling.docx.
27 PGE Response to AWEC Data Request 242 part g.
28 Exhibit AWEC 305 Faraday Economic Analysis.

Q. WHAT ALTERNATIVES DID PGE CONSIDER IN ITS ECONOMIC ANALYSIS?

A. PGE's analysis is framed as a comparison to status quo. It compares the present value revenue requirement of the project with the present value revenue requirement of a "Status Quo" scenario. However, the status quo scenario includes a greater capital expenditure than the Faraday Project. The primary difference between the two scenarios appears to be a rewind of existing generators rather replacement of existing generators. PGE provided no documentation supporting the need for capital expenditures in the status quo scenario other than a seismic study of the Faraday Powerhouse.[29]

Q. WHAT ALTERNATIVES DO YOU BELIEVE PGE SHOULD HAVE STUDIED?

A. PGE asserts that the $188 million Faraday Project was necessary due to seismic and flooding risk. PGE points to seismic and flooding risks and asserts that the upgrades were required to maintain its FERC license.[30] However, PGE's seismic study did not require the majority of the upgrades implemented in the Faraday Project. PGE's testimony identifies three potential alternatives, all of which appear to have been dismissed by PGE prior to performing an initial evaluation of the options. These options were:

1. Do nothing beyond routine maintenance for the existing powerhouse and original 9 turbine-generators.
2. Retrofit the existing powerhouse structure and maintain original turbine-generators.
3. Replace the powerhouse structure and maintain original turbine-generators.
4. Replace the powerhouse structure and install new turbine-generators.[31]

---

29 PGE / 805C and PGE Response to AWEC Data Request 242 part e.
30 PGE Response to AWEC Data Request 242 part a.
31 PGE / 800 Jenkins – Bekkedahl / 26

PGE only appears to have performed economic analysis comparing options 3 and 4.[32] PGE appears to have failed to analyze options 1 and 2 due to risk of losing its FERC license.[33]

Q. WAS THERE RISK OF LOSING FERC LICENSE UNDER OPTIONS 1 AND 2?

A. No. PGE states that "[t]he 2010 FERC license provides that 'if the Licensee shall cause or suffer essential project property to be removed or destroyed or to become unfit for use, without adequate replacement, […], the Commission will deem it to be the intent of the Licensee to surrender the license.'"[34] This requirement clearly provides PGE the opportunity for adequate replacement. Thus, in the event that flooding or earthquake causes Faraday property to be removed, destroyed, or unfit for use, PGE could avoid losing its license by inadequately replacing the property.

Additionally, Faraday's flood and seismic risk that PGE identifies has been present and managed by PGE for over 100 years. It is unreasonable for PGE to dismiss the possibility of continuing to manage these risks consistent with prior practice, or to perform minimal seismic retrofits. Both of these options involve much less capital investment than the Faraday Project.

Q. WHAT IS THE NET PRESENT VALUE OF THE PROJECT UNDER OPTION 1?

A. The net present value of the Faraday Project relative to Option 1 is [redacted].[35]

Q. WHAT IS THE NET PRESENT VALUE OF THE PROJECT UNDER OPTION 2?

A. The net present value of the Faraday Project relative to Option 2 is [redacted].[36]

---

32 PGE / 800 Jenkins – Bekkedahl / 29:10-11.
33 PGE / 800 Jenkins – Bekkedahl / 28.
34 PGE / 800 Jenkins – Bekkedahl / 27:18-21.
35 Confidential Exhibit AWEC 305 Faraday Economic Analysis.
36 Confidential Exhibit AWEC 305 Faraday Economic Analysis.

Q. WHAT IS YOUR CONCLUSION REGARDING THE ALTERNATIVE OPTIONS?

A. Options 1 and 2 have similar net present value and are the most economic options. PGE should have performed additional evaluation of Options 1 and 2 and selected the most appropriate of these two options.

Q. YOU NOTED THAT PGE'S OWN ANALYSIS SHOWS THAT OPTION 3 WAS MORE ECONOMIC THAN THE FARADAY PROJECT. DID PGE PRESENT THIS RESULT TO IT'S BOARD?

A. No. PGE does not appear to have notified its Board that it had selected an option that it knew to be uneconomic. When asked why PGE continued with the project despite its economic analysis, PGE pointed to FERC license requirements.[37] PGE was asked if the economic analysis of Option 3, which showed the Faraday Project was uneconomic, was presented to its Board. In response PGE directed AWEC to a presentation to the PGE Board approving the project.[38] This presentation contains none of the cost benefit analysis performed by PGE.[39]

Q. WHAT IS YOUR RECOMMENDATION REGARDING PGE'S DECISION TO PROCEED WITH THE FARADAY PROJECT?

A. I recommend that the Commission find PGE's decision to proceed with the Faraday Project imprudent. I recommend that the Commission disallow PGE's return on equity associated with this project but allow PGE to recover interest expense associated with the project at PGE's long-term cost of debt.

---

37 PGE Response to AWEC Data Request 242 part a.
38 PGE Response to AWEC Data Request 242 part a.
39 PGE's response to AWEC Data Request No. 061, confidential Attachment 061-A, file "2019-04-23 Approval of Incremental Multiyear Capital Projects_Redacted".

ii. PGE Failed to Prudently Manage the Faraday Project.

Q. WHAT OTHER CONCERNS DO YOU HAVE WITH THE FARADAY PROJECT?

A. PGE is over-budget on the Faraday Project. The initial expected rate base at the time PGE's Board gave approval to proceed was [redacted] million.[40] PGE's requested rate base for this project is [redacted] million, over twice the forecasted cost.[41] PGE was aware of the flooding risks that drove cost over-runs. PGE should have managed the scope and terms of the initial contract to prevent ratepayers from bearing the burden of these cost over-runs.

Q. WHAT CAUSED THESE COST INCREASES?

A. The cost increases are primarily due to worksite flooding and project delays.[42]

Q. WAS PGE AWARE OF FLOODING RISK?

A. PGE asserts that flooding events were "unprecedented and catastrophic" and "not foreseeable when PGE entered the original construction contract."[43] However, this is inaccurate. PGE's project justification included mitigating flood risk. Thus, it is very reasonable to expect that flood risk would be included as a major project risk. In an email dated November 19, 2019, over a year before the flood events, the PGE Faraday Repower Project Manager and Contractor discussed "solutions for … flood contingency."[44] In the November 19, 2019 email, the PGE Faraday Repower Project Manager stated that this was the "highest risk item, so it's prudent to bring some executive oversight."[45]

---

[40] PGE's response to AWEC DR 059
[41] PGE's response to AWEC DR 047 Attach A
[42] UE 416 / PGE / 800 Jenkins – Bekkedahl / 41, 46-47.
[43] UE 416 / PGE / 800 Jenkins – Bekkedahl / 41:16-17.
[44] PGE Response to AWEC DR 58_000001236.
[45] PGE Response to AWEC DR 58_000001236.

Q. WERE THE FLOODS AFFECTING THE PROJECT WERE ABNORMAL OR UNPRECEDENTED?

A. No, the floods affecting the project were consistent with historical water flows. The project experienced floods with the following stream flows:

- 2020-01-11: 6,130 cfs;
- 2020-12-20: 20,900 cfs; and
- 2021-01-13: 31,000 cfs.[46]

The Clackamas River stream flow at Estacada exceeds 6,130 cfs every season and was virtually guaranteed to be experienced during the duration of the Faraday Project. Flows exceeded 20,900 cfs on 13 days from 2000 to 2019[47] and were very likely to be experienced over a two-year period.[48] Flows exceeded 31,000 cfs on four days from 2000 to 2019[49] and were reasonably likely to occur over a two year period.[50] All three stream flows that flooded the project were below PGE's severe flood level for PGE's Emergency Action Plan ("EAP") for hydro operations on the Clackamas River.[51] Given that the river regularly floods to the levels experienced during the Faraday Project, and that all three flooding events were below PGE's severe flood level, it is unreasonable for PGE to call these events unprecedented and catastrophic.

---

[46] PGE Response to AWEC Data Request 231

[47] USGS, Clackamas River at Estabacda, OR – 14210000 *available at:* https://waterdata.usgs.gov/monitoring-location/14210000/.

[48] If these events correspond to an annual risk of 65% (13/20) the chance of at least one 20,900 foot flood in any two years is 88%.

[49] USGS, Clackamas River at Estabacda, OR – 14210000 *available at:* https://waterdata.usgs.gov/monitoring-location/14210000/.

[50] If these events correspond to an annual risk of 20% (4/20) the chance of at least one 31,000 foot flood in any two years is 36%.

[51] PGE Response to AWEC Data Request 231

Q. DID PGE'S CONTRACT INCLUDE PROTECTIONS AGAINST FLOODING AND DELAYS?

A. Yes. PGE's initial contract included a guaranteed maximum price of [redacted][52] It also included limitations to allowances for flood risk[53] and liquidated damages of $30,000 per day for project delays.[54] PGE appears to have given up rights to these contract protections when it terminated its initial contractor.[55]

Q. WHAT IS YOUR RECOMMENDED TREATMENT OF PROJECT COST OVERRUNS?

A. PGE should have maintained the original contract protections for customers against floods, project delays, and other cost over-runs. I recommend that the Commission find PGE's failure to maintain the original guaranteed maximum cost to constitute imprudent management. If the Commission makes this finding, I recommend that PGE be excluded from recovering return on and return of all costs exceeding the initially budgeted amount of [redacted] million.

Q. WHAT IS THE COMBINED IMPACT OF YOUR TWO RECOMMENDATIONS?

A. My recommendations remove $188 million from rate base. The total depreciation expense associated with the Faraday Project is approximately $3.8 million. However, because my recommendations allow PGE to recover its invested capital for the initially budgeted amount of [redacted] million, my recommendation only decreases depreciation expense by [redacted] million. Under my recommendation PGE is allowed to recover interest expense on the original budget

---

[52] OPUC Data Request No. 358 Confidential Attachment 358-B, UE 394 to OPUC Data Request No. 591, confidential Attachments 591 B page 1.

[53] OPUC Data Request No. 358 Confidential Attachment 358-B, UE 394 to OPUC Data Request No. 591, confidential Attachments 591 B page 3.

[54] OPUC Data Request No. 358 Confidential Attachment 358-B, UE 394 to OPUC Data Request No. 591, confidential Attachments 591 A page 2.

[55] UE 416 PGE Response to AWEC DR No. 236 Confidential Attachment A.

of [redacted] million. If PGE's cost of long-term debt is 4.317 percent, total interest expense is [redacted] million. The revenue requirement impact of my adjustments is $9.071 million.

V. BEAVER

Q. WHAT IS THE BEAVER EMISSIONS REDUCTIONS PROGRAM?

A. The Beaver Emissions Reduction Program ("Beaver Project")[56] is a project that modifies the 500 MW Beaver plant to reduce emissions. PGE claims that this upgrade was necessary to comply with regional haze emissions requirements. However, this project is a costly project that provides little rate payer benefit. PGE's Beaver plant could continue to operate consistent with historical operations without violating regional haze emissions requirements. Furthermore, the conversion of this plant materially reduces the reliability of PGE's system because it converts Beaver from dual fuel to natural gas. PGE does not have firm natural gas supply for Beaver, thus this conversion reduces PGE's ability to meet peak winter demand and makes PGE more susceptible to pipeline outages.

Q. WHAT IS THE COST OF THE BEAVER PROJECT?

A. The Beaver Project is expected to cost over [redacted] million.[57] PGE has requested to include $56.9 million in rate base in this case associated with components of the project that are expected to transfer to plant by December 31, 2023.[58] These components also cause a $3.3 million increase to depreciation expense. Once the project is completed the annual capital carrying cost will be over [redacted].[59]

---

56 In some PGE testimony and workpapers the Beaver Emissions Reduction Program is also referred to as the Beaver Modernization Program.

57 UE 416_AWEC DR 158_Attach A CONF

58 PGE / 800 Jenkins – Bekkedahl / 3:9.

59 Exhibit AWEC 306.

In addition to these direct costs, the Beaver Project has indirect costs associated with loss of capacity value. As noted above, PGE does not have firm natural gas supply for the Beaver Plant. For planning purposes, PGE assumes that the Beaver Plant has zero availability between November and March.[60] PGE does have large on-site bio-diesel storage for the Beaver Plant that can provide winter capacity. Converting the plant to natural gas eliminates PGE's ability to rely on Beaver during the winter or in the event of a major pipeline outage. This reduces PGE's generation capacity by 500 MW. PGE cost of capacity is $214.24 per kW-Year. This represents an indirect expense of $107 million per year. The combined direct capital carrying costs and indirect costs of this project are [redacted] million per year.

Q. DOES THE BEAVER PROJECT HAVE ANY NON-EMISSIONS BENEFITS?

A. The Beaver Project was expected to reduce 2022 net power costs by $60,000.[61] This value may only reflect a portion of savings for the total project. Assuming it represents the savings for a single unit for half a year, the annualized amount for six units would be $720,000. This is less than one percent of the annual cost of the project.

Q. DOES THE BEAVER PROJECT EXTEND THE LIFE OF THE BEAVER PLANT?

A. No. While PGE initially indicated that the project extends the life of the Beaver Plant from 2030, to 2040,[62] this appears to have been an error. The Beaver Plant had an expected life of 2035 in 2019, prior to the initial approval of the Beaver Project.[63]

---

60 PGE / 300 Schwartz – Outama – Cristea / 38 line 4.
61 UE 391 PGE/100 Vhora – Outama – Batzler / 48.
62 PGE / 800 Jenkins – Bekkedahl / 3 and PGE's Response to AWEC DR 212.
63 PGE's Response to AWEC DR 283 Redacted.

Q. IF THE PROJECT HAS DEMINIMUS ECOMONMIC VALUE RELATIVE TO ITS COST, REDUCES PGE'S PLANNING CAPACITY BY 500 MW, AND DOES NOT EXTEND THE LIFE OF THE PLANT, HOW DOES PGE JUSTIFY THE INVESTMENT IN THE BEAVER PROJECT?

A. PGE states that the primary driver of the project is to meet stipulated environmental regulations. PGE declined indicate whether the project was cost effective.[64] PGE's directed AWEC to its economic analysis of the cost effectiveness of the project.[65] PGE's analysis shows the project to be highly uneconomic. Furthermore, PGE's analysis was out of date and not revised after project costs tripled.[66]

Q. DID PGE CONSIDER ALTERNATIVES FOR EMISSIONS COMPLIANCE?

A. PGE considered three alternatives:

1. Full repower,
2. Selective Catalytic Reduction ("SCR") addition, and
3. Combustion system upgrade.[67]

The first two alternatives considered by PGE appear to have been non-starters, as PGE did not include these alternatives in its economic analysis.[68] The full repower alternative was dismissed due to the limited remaining life of the turbine. The SCR option was dismissed due to limited space.[69]

Q. ARE THERE COMPLIANCE OPTIONS THAT PGE FAILED TO CONSIDER?

A. Yes. PGE failed to consider two important alternatives:

---

[64] PGE Response to AWEC Data Request 281.

[65] PGE Response to AWEC Data Request 281 points to PGE's response to AWEC Data Request 158, Attachment 158-B (Confidential).

[66] PGE Response to AWEC Data Request 282 Redacted states that the tripling of project costs was due to increasing the number of units from 2 to 6. However, the per-unit capital cost in AWEC Data Request 158, Attachment 158-B (Confidential) is nearly one third currently estimated per-unit cost.

[67] PGE Response to AWEC Data Request 206 part f.

[68] PGE Response to AWEC Data Request 158, Attachment 158-B (Confidential).

[69] PGE Response to AWEC Data Request 206 part f.

1. Perform no plant changes and limit dispatch of the Beaver Plant in years where emission limits are binding.
2. Perform combustion system upgrades on the minimum number of units necessary to achieve compliance, or
3. Perform combustion system upgrades on fewer than the minimum number of units necessary to achieve compliance, and achieve remaining compliance through limited plant dispatch.[70]

Q. WHAT ARE THE EMISSIONS LIMITS RESULTING FROM THE REGIONAL HAZE STIPULATION?

A. The stipulation limits combined emissions for both the Beaver and Port Westward 1 plants. The table below summarizes emissions limits.[71] The binding limit for these plants is NOx. The NOx limit declines each year in August from 2021 to 2025.

Table LK-3: Stipulated Emissions Limits

Pollutant	Title V PSEL (Condition 59, Table 6)	Stipulated Agreement and Final Order (SAFO)				
		Year 1 (8/1/21 - 7/31/22)	Year 2 (8/1/22 - 7/31/23)	Year 3 (8/1/23 - 7/31/24)	Year 4 (8/1/24 - 7/31/25)	Year 5 (8/1/25 and later)
PM/PM10	241	99				
CO	1,104	Unchanged by SAFO				
NOx	3,776	1,900	1,542	1,184	826	436
SO2	595	99				39
VOC	118	Unchanged by SAFO				

Q. WHAT HAVE HISTORIC EMISSIONS BEEN FOR THESE PLANTS?

A. Confidential Table LK-4 below summarizes combined emissions for Beaver and Port Westward 1 from 2018 to 2022.[72]

70 PGE Response to AWEC Data Request 280 indicates these compliance options were not considered.
71 PGE Response to AWEC Data Request 278.
72 PGE Response to AWEC Data Request 279 Confidential Attachment A.

Confidential Table LK-4: Historic Emissions for Beaver and Port Westward 1

[redacted]

Note that in in all five years, NOx emissions are compliant until August 1, 2025. This means that PGE could have continued operating the Beaver Plant consistent with historic operations until August 2025. Thus, PGE could have delayed the Beaver Project for at least one year. Note also that from 2018 to 2020 emissions were below or close to the August 2025 NOx limit.

Q. DO YOU EXPECT THAT PGE'S FUTURE OPERATIONS OF THE BEAVER PLANT WILL REQUIRE EMISSIONS REDUCTIONS?

A. No, this seems unlikely. PGE admits that Beaver can meet the stipulated emissions requirements under the current plant configuration if annual generation does not exceed 850,000 MWh. PGE asserts that Beaver will generate 1,330,065 MWh by 2029 in order to integrate renewables and meet customer load.[73] However, this assertion is not consistent with PGE's IRP data. Total generation for PGE's 2023 IRP forecasts that Beaver will provide, on average [redacted] of retail energy per year, and Beaver retail generation will not exceed 850,000 MWh in any planning year. See Confidential Table LK-5 below.[74] The majority of energy modeled as generated by the Beaver Plant in the 2023 IRP is actually wholesale sales.

[73] PGE Response to AWEC DR 280.
[74] PGE Response to AWEC DR 284.

Confidential Table LK-5: Beaver Retail Generation by Year

[redacted]

Q. ARE PGE'S WHOLESALE SALES FORECAST FOR BEAVER ACCURATE?

A. No, these sales are not reliable for two reasons. First, the heat rate used in the IRP was 10,176, while PGE's actual heat rate is [redacted].[75] The actual dispatch costs for the Beaver Plant are [redacted] percent higher than modeled in the IRP. If PGE had used the actual heat rate for Beaver in the IRP, the higher dispatch cost would have made Beaver uneconomic in a greater number of hours and thus reduced the amount of economic energy sales.

[75] PGE Response to AWEC Data Request 158 Highly Confidential.

Q. WHAT IF THE COMMISSION AGREES WITH PGE'S FORECAST OF GENERATION FROM BEAVER?

A. If the Commission agrees with this forecast, the Commission should require that PGE demonstrate that net revenue from wholesale sales are sufficient to justify the capital cost of the project and the loss of capacity value. Furthermore, a finding in agreement with PGE's IRP forecast would support the argument Mr. Mullins makes in his Opening Power Cost Testimony on behalf of AWEC with respect to PGE's modeling of Beaver for power cost purposes.[76]

Q. WHAT IS IMPACT OF THE BEAVER PROJECT ON NOX EMISSIONS?

A. Beaver's current NOx emissions rate is [redacted] per GWh.[77] The emissions rate after the Beaver Project is [redacted] per GWh.[78] Thus, if PGE implements upgrades at all units Beaver emissions could reduce by nearly 90 percent. The number of units needed to meet 2025 emissions limits depends on expectations about future operations.

Q. IS A REDUCTION OF 90 PERCENT NECESSARY TO MEET EMISSIONS LIMITS UNDER PGE'S UNREALISTIC FORECAST OF BEAVER'S WHOLESALE SALES?

A. No, even if PGE's inflated generation at Beaver is used to measure generation, PGE only needs to accomplish a 36 percent reduction in emissions.[79] This means that PGE could achieve target emissions levels while only modifying two or three units.[80]

---

76 AWEC/100, Mullins/29:19-30:17.

77 Calculated from UE 416_AWEC DR 206_Attach B CONF and PGE Response to AWEC Data Request 279 Confidential Attachment A.

78 UE 416 AWEC DR 158 Attach C_HIGHLY CONF calculated as [redacted]

79 Calculated as 1-850,000MWh / 1,330,000 MWh.

80 Emissions controls on two of six plants would achieve 33 percent of emissions controls on all Beaver plants, for a total reduction of 29.7 percent. The remaining emissions reductions could be accomplished by limiting dispatch of Beaver in hours where wholesale sales are only marginally economic. Alternatively, controls on three units could reduce emissions by 45 percent, which would allow a large buffer between forecasted emissions and emissions limits but may not be as economical.

Q. DID PGE HAVE ALTERNATIVES TO THE STIPULATED EMISSIONS LIMITS?

A. Yes, PGE could have performed a "four-factor" analysis to establish emissions limits.[81] Recent Oregon and Washington legislation has greatly limited coal generation in the region, and will greatly reduce gas generation over the next ten years. It is reasonable to expect that as this legislation naturally reduces emissions, visibility at Mount Rainier will naturally improve. Closure of the remaining unit at the Centralia coal-fired facility in 2025 alone will likely have an appreciable impact on regional haze. Given the substantial expected reduction in regional pollutants due to other factors, it is reasonable to expect that little to no NOx emissions reductions are necessary at Beaver to achieve visibility standards. However, PGE didn't even develop a budget to perform a four-factor analysis.[82] Given that the annual cost of PGE's investment is nearly $100 million per year, a preliminary investigation of at least estimating the cost of a four-factor analysis should have been performed.

Q. WILL PGE FACE BINDING EMISSION CONSTRAINTS AT THE BEAVER PLANT EVEN WITH THE FULL IMPLEMENTATION OF THE BEAVER PROJECT?

A. Yes. The Beaver Project does [redacted] PM emissions.[83] PGE's PM emissions in 2020 exceed the new PM emissions limits. If my expectations that the Beaver plant will experience low dispatch in the future are accurate this constraint may not be binding. However, if PGE's forecast of future beaver dispatch is accurate, beaver may face binding constraints due to PM

---

[81] OAR 340-223-0120(1) ("A four factor analysis is an emissions control analysis that shall include: (a) All emissions units for the source; and (b) Information sufficient to determine, at each emissions unit: (A) The costs of any and all controls that could be used to reduce round II regional haze pollutants, including an estimate of the cost per ton of each round II regional haze pollutant reduced and all control technologies in use by similar emission units, either at that source or at other sources or locations; (B) How soon the source believes it would be practicable to install to install controls identified under paragraph (A); (C) The energy and non-air quality environmental impacts of installing controls identified under paragraph (A); and (D) The remaining useful life of each emissions unit.").

[82] PGE Response to AWEC Data Request 278

[83] PGE Response to AWEC DR 158_Attach C_HIGHLY CONF.

emissions. This eliminates any potential value from PGE's Beaver Project investments in NOx reduction.

Q. WHAT IS YOUR RECOMMENDATION ON THIS ISSUE?

A. My primary recommendation is that the Commission find that the Beaver Project could have been avoided through a four-factor analysis, limits on annual generation, or was unnecessary because future Beaver generation is expected to be low. I recommend that the full amount of the investment be disallowed as imprudent. This recommendation reduces rate base by $56.9 million and depreciation expense by $3.3 million. I have not determined the property tax impact of this recommendation.

If the Commission does not make a full prudence disallowance, I recommend the Commission find that Beaver does not face binding emissions constraints until August 1, 2025, and that emission reduction upgrades are only necessary for two of six units. I recommend that all costs of the Beaver Project investment be disallowed as investment before need and that the investment be reconsidered in a future rate case.[84] This finding would eliminate all costs associated with the Beaver Project in this case, but would allow PGE to recover some most costs from the Beaver Project in a future rate case. Thus, it introduces regulatory lag on PGE's recovery of the Beaver Project but would not prevent PGE from requesting return of and on the undepreciated amount in a future rate case. This recommendation reduces rate base by $56.9 million and depreciation expense by $3.3 million. I have not determined the property tax impact of this recommendation.

---

84 *See* Docket No. UG 221, Order No. 12-437, at 16-17 (Nov. 16, 2012).

VI. WORLD TRADE CENTER

Q. WHAT IS THE WORLD TRADE CENTER?

A. The World Trade Center ("WTC") is a three-building complex in downtown Portland with approximately 500,000 rentable square feet. PGE currently occupies 317,000 square feet in the WTC under a lease with PGE affiliate 121 SW Salmon Street Corporation ("121 SW Salmon").[85] The WTC buildings were constructed between 1975 and 1978 as PGE's corporate headquarters.[86] As an affiliate, PGE's lease with 121 SW Salmon is subject to the Commission's lower of cost or market affiliate interest standards. 121 SW Salmon recently purchased the WTC for 26 percent of its market value.[87] This discounted purchase was only available to 121 SW Salmon because of its affiliation with PGE and because of the nature of PGE's pre-existing long term lease of the WTC. PGE has a preexisting below-market lease for a portion of the WTC. This preexisting lease impaired the value of the building for other potential buyers. PGE's decision to purchase the WTC was performed with knowledge about PGE's upcoming development of the integrated operations center ("IOC"). The development of the IOC alleviated the impairment of the below-market lease and allowed PGE to outbid other potential market participants without this knowledge.

AWEC filed testimony on the appropriate affiliated interest transfer price for the WTC in UE 394. This case was resolved through settlement without addressing the long-term treatment of the WTC. The transfer price calculated by AWEC in UE 394 was intended to be a permanent transfer price for the duration of the lease. I recommend that the Commission adopt the transfer price proposed by AWEC in UE 394 for the duration of the WTC lease. The

---

85 Exh. AWEC/307 at 62 (UE 394 Testimony).
86 World Trade Center Portland, Frequently Asked Questions, *available at*: https://wtcpdx.com/about-us/#faqs.
87 Exh. AWEC/307 at 62 (UE 394 Testimony).

relevant portion of AWEC's UE 394 testimony and exhibits are included in Exhibit AWEC 307.

Q. WHAT IS THE IMPACT OF YOUR RECOMMENDATION?

A. PGE has included $7,636,467 in WTC lease expense in the test year. The UE 394 recommended affiliate transfer price was [redacted] This results in a lease expense adjustment of [redacted].[88]

VII. FLEET FUEL

Q. PLEASE SUMMARIZE YOUR CONCERNWITH FLEET FUEL

A. PGE intends to electrify the majority of its fleet in 2024. The table below illustrates PGE's expected electrification by the end of 2024.[89] Despite this heavy electrification, PGE projects an increase in test year fleet fuel expense from $2.3 million in 2021 to $3.9 million in 2024. This increase is unreasonable given the heavy electrification expected in 2024 and the return of fuel prices to normal following the price spikes associated with Russia's war in Ukraine.

Table LK-6: PGE Fleet Electrification Targets

	Electric Share
Class 1	100%
Class 2	70%
Class 3-6	40%
Class 7-8	30%
Forklifts	100%

[88] Via email, PGE provided AWEC with authorization to use confidential information from UE 394 under the protective order in this docket.

[89] PGE Response to OPUC Data Request 263 Attachment B.

Q. WHAT IS YOUR RECOMMENDED TREATMENT OF FUEL COSTS?

A. I recommend adjusting test year fuel cost to be equal to the year end 2024 share of non-electric vehicles times the 2021 fuel expense. The table below summarizes this adjustment.[90]

Table LK-7: Fuel Cost by Vehicle Class

[redacted]

Q. HOW DO YOU APPORTION YOUR ADJUSTMENT BETWEEN RATE BASE AND EXPENSE?

A. I recommend that the adjusted fuel cost be apportioned between rate base and expense consistent with PGE's filed case. This is summarized in the table below. [91] The total revenue requirement impact of this adjustment is a reduction of $1.876 million.

Table LK-8: AWEC Fuel Cost Adjustment

[redacted]

Q. WHY IS IT REASONABLE TO USE 2021 FUEL COSTS AS THE STARTING POINT FOR FORECASTING FUEL EXPENSE?

A. 2022 fuel costs are an unreasonable representation of 2024 fuel costs because they represent an extreme outlier in wholesale fuel prices.

---

90 Calculated from PGE Response to AWEC Data Request 190 Confidential attachment A, Attachment B, and PGE Response to OPUC Data Request 263.

91 Calculated from PGE Response to AWEC Data Request 190 Attachment B.

Q. DOES THIS CONCLUDE YOUR OPENING TESTIMONY?

A. Yes

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UE 416

In the Matters of	)
	)
PORTLAND GENERAL ELECTRIC COMPANY,	)
	)
	)
Request for a General Rate Revision.	)
	)

EXHIBIT AWEC/301

QUALIFICATION STATEMENT OF LANCE D. KAUFMAN

CURRICULUM VITAE

LANCE KAUFMAN
Bardwell Consulting, Ltd
4801 W. Yale Ave.
Denver, Colorado 80219
lance@bardwellconsulting.com
1-541-515-0380

EDUCATION:

University of Oregon	Ph.D.	Economics	2009 – 2013
University of Oregon	M.S.	Economics	2007 – 2009
University of Anchorage Alaska	B.B.A.	Economics	2001 – 2005

CERTIFICATIONS:

Certified Depreciation Professional	Society of Depreciation Professionals	2018

PROFESSIONAL EXPERIENCE:

Principal Economist	Bardwell Consulting	2014 – Present
Senior Economist	Oregon Public Utility Commission	2015 – 2018
Public Utility Advocate	Alaska Department of Law	2014 – 2015
Senior Economist	Oregon Public Utility Commission	2013 – 2014
Instructor	University of Oregon	2008 – 2012
Research Assistant	University of Alaska Anchorage	2003 – 2008

PROFESSIONAL MEMBERSHIPS:

Society of Depreciation Professionals	2015 – Present
American Economics Association	2017 – Present

PUBLICATIONS:

- Kaufman, L.D. (2013). *Three Essays on Governance Structure in the Hospital Industry.* (PhD Dissertation) University of Oregon.

RESEARCH, CONSULTING, AND ECONOMETRIC ANALYSIS:

- Nichols Kaster, PLLP, Minneapolis, Minnesota, 2013 –
  Deposed as expert witness for the plaintiffs re analysis of termination of older employees in re Raymond, et al. v. Spirit Aerosystems, Inc., Case No. 16-1282-JTM-GEB, United States District Court, District of Kansas.
- Jester, Gibson & Moore, Denver, CO 2022
  Deposed as an expert witness for defendants and countersuit plaintiffs regarding lost earnings in Franklin D. Azar & Associates, P.C., v. Ivy Ngo v. Franklin D. Azar.
- Georgia Public Service Commission Public Interest Advocacy Staff, Atlanta, GA (2022)
  Provided **Testimony** as an expert witness in Docket No. 44280 Georgia Power Company's 2022 Rate Case Depreciation Study.
- Inland Empire Paper Co., Spokane, WA (2020)

Provided **Testimony** as an expert witness in WUTC Docket No. UE-200900, Avista Corp's 2020 Rate Case regarding avoided cost pricing for a special contract.

- Davison Van Cleve, PC, Portland, OR 2021
  Provided **Testimony** as an expert witness for Alliance of Western Energy Consumers regarding depreciation, cost of service, rate design, and revenue requirement in Portland General Electric Company 2021 General Rate Case, Public Utility Commission of Oregon, Docket No. UE 394.
- Davison Van Cleve, PC, Portland, OR 2021
  Provided comments as an expert witness for Alliance of Western Energy Consumers in Puget Sound Energy's 2022 General Rate Case, Washington Utilities and Transportation Commission.
- Davison Van Cleve, PC, Portland, OR 2022
  Provided comments as an expert witness for Alliance of Western Energy Consumers in Puget Sound Energy's 2022 General Rate Case, Washington Utilities and Transportation Commission.
- Davison Van Cleve, PC, Portland, OR 2021
  Provided comments as an expert witness for Alliance of Western Energy Consumers in Avista Corp's Clean Energy Implementation Plan, Washington Utilities and Transportation Commission.
- Davison Van Cleve, PC, Portland, OR 2021
  Provided comments as an expert witness for Alliance of Western Energy Consumers in PacifiCorp's General Rate Case, Public Utility Commission of Oregon, Docket No. UE 399.
- Davison Van Cleve, PC, Portland, OR 2021
  Provided comments as an expert witness for Alliance of Western Energy Consumers in Puget Sound Energy's Clean Energy Implementation Plan, Washington Utilities and Transportation Commission.
- Hagens Berman Sobol Shapiro LLP, Phoenix, Arizona, 2021
  Deposed as an expert witness for plaintiffs re calculation of economic harm due to breach of contract in Kronenberg, et al. vs. Allstate Insurance Company, et al. United States District Court Eastern District of New York Case No.: 18-cv-06899 (NGG) (JO).
- Baumgartner Law, LLC, Denver, CO, 2021
  Deposed as an expert witness for plaintiffs re calculation of economic harm due to injury in re In Re: Bernadette Romero and Leonard Martinez v. City of Westminster
- Killmer, Lane, and Newman, LLP, Denver, Colorado, 2020
  Retained as expert witness for plaintiff re racial disparities in police use of force re Estate of Elijah J. McClain V. City Of Aurora, Colorado, Case No. 1:19-cv-01160-RM-MEH, United States District Court, District of Colorado.
- Hagens Berman Sobol Shapiro LLP, Phoenix, Arizona, 2020
  Deposed as an expert witness for plaintiffs re calculation of economic harm due to breach of contract in Fortson, et al. v. Garrison Property and Casualty Insurance Co. United States District Court Middle District of North Carolina Civil Action No. 1:19-cv-294.
- Hagens Berman Sobol Shapiro LLP, Phoenix, Arizona, 2020
  Deposed as an expert witness for plaintiffs re calculation of economic harm due to breach of contract in Lewis and Lewis, et al. v. Government Employees Insurance Co. United

States District Court For the District of New Jersey Civil Action No. 1:18−CV−05111−RBK−AMD.

- Cable Huston, LLP, Portland, OR 2020
  Retained as an expert witness for Alliance of Western Energy Consumers regarding revenue requirement, rate spread and rate design in Cascade Natural Gas Corporation Request for General Rate Revision, Public Utility Commission of Oregon, Docket No. UG 390.
- Davison Van Cleve, PC, Portland, OR 2020
  Retained as an expert witness for Alliance of Western Energy Consumers regarding net power costs in Portland General Electric Company 2021 Annual Power Cost Update Tariff, Public Utility Commission of Oregon, Docket No. UE 377.
- Davison Van Cleve, PC, Portland, OR 2020
  Retained as an expert witness for Alliance of Western Energy Consumers regarding net power costs in Portland General Electric Company 2021 Annual Update Tariff, Public Utility Commission of Oregon, Docket No. UE 381.
- Davison Van Cleve, PC, Portland, OR 2020
  Retained as an expert witness for Alliance of Western Energy Consumers regarding revenue requirement, rate spread and rate design in Nevada Power Company 2021 General Rate Case, Public Utility Commission of Nevada, Docket No. 20-06003
- Frank & Salahuddin LLC, Denver, Colorado, 2020
  Retained as an expert witness for plaintiffs regarding calculation of lost earnings due to wrongful death.
- Level Development Group, LLC, Denver, Colorado, 2020
  Develop real estate valuation model for establishing sale price of newly constructed residential housing.
- Hagens Berman Sobol Shapiro LLP, Phoenix, Arizona, 2020
  Deposed as an expert witness for plaintiffs re calculation of economic harm due to breach of contract in Jeff Olberg v. Allstate Insurance Company, Case No. C18-0573-JCC, United States District Court, Western District of Washington at Seattle.
- Hagens Berman Sobol Shapiro LLP, Phoenix, Arizona, 2020
  Deposed as an expert witness for plaintiffs re calculation of economic harm due to breach of contract in re Cameron Lundquist v. First National Insurance Company of America, Case No. 18-cv-05301-RJB, United States District Court, Western District of Washington at Tacoma.
- Killmer, Lane, and Newman, LLP, Denver, Colorado, 2020
  Deposed as expert witness for plaintiff re racial disparities in police use of force re Brandon Washington V. City Of Aurora, Colorado, Case No. 1:19-cv-01160-RM-MEH, United States District Court, District of Colorado.
- Davison Van Cleve, PC, Portland, OR 2020
  Retained as an expert witness for Alliance of Western Energy Consumers regarding coal plant pollution control investments, coal plant decommissioning costs, rate spread and rate design re PacifiCorp 2020 Request for a General Rate Revision, Public Utility Commission of Oregon Docket No. UE 374.
- Davison Van Cleve, PC, Portland, OR and Washington Attorney General, 2020

Retained as an expert witness for Packaging Company of America and Washington Public Council regarding decommissioning costs and rate design re PacifiCorp 2020 Request for a General Rate Revision, Washington Utility and Transportation Commission.

- Sanger Law, PC, Portland, OR, 2019
  Retained as a consultant for Renewable Energy Coalition and for Northwest & Intermountain Power Producers Coalition to provide analysis of PacifiCorp avoided costs in a Utility PURPA Compliance Filing at the Washington Utility and Transportation Commission Docket, No. UE-190666.
- Sanger Law, PC, Portland, OR, 2019
  Retained as a consultant for Northwest & Intermountain Power Producers Coalition to provide analysis of Portland General Electric avoided costs in support of testimony to the Oregon Legislature.
- Powder River Basin Resource Council, Laramie, Wyoming, 2019.
  Testified as an expert witness for Powder River Basin Resource Council regarding coal plant closures re PacifiCorp 2019 Integrated Resource Plan, Wyoming Public Service Commission Docket No. 90000-147-XI-19.
- The Law Office of Ralph Lamar, Arvada, CO 2019
  Deposed as an expert witness for plaintiffs regarding lost profits of a Farmers insurance agency
- Jester, Gibson & Moore, Denver, CO 2019
  Retained as an expert witness for plaintiffs regarding lost earnings in an ADEA wrongful termination matter.
- Albrechta & Coble, Ltd. Fremont, OH 2019
  Retained as an expert witness for plaintiff regarding lost earnings in Perez v. CAPCO, a race related wrongful termination matter.
- Conrad Law, PC, Salt Lake City, UT 2019
  Retained as an expert witness for Ellis-Hall Consultants, LLC. regarding economic damages in Ellis-Hall Consultants, LLC. et. al. v. George B. Hofmann IV, United States District Court, District of Utah, Central Division.
- Davison Van Cleve, PC, Portland, OR 2019
  Retained as an expert witness for Alliance of Western Energy Consumers regarding net variable power cost calculations in PORTLAND GENERAL ELECTRIC COMPANY, 2020 Annual Power Cost Update Tariff Public Utility Commission of Oregon Docket No. UE 359.
- Sanger Law, PC, Portland, OR, 2019
  Testified as an expert witness for Renewable Energy Coalition and Rocky Mountain Coalition for Renewable Energy regarding Qualified Facility avoided costs in Application of Rocky Mountain Power for a Modification of Avoided Cost Methodology and Reduced Term of PURPA Power Purchase Agreements Public Service Commission of Wyoming Docket No. 20000-545-ET-18
- Sanger Law, PC, Portland, OR, 2019
  Retained as an expert witness for Cafeto Coffee Company regarding the necessity, design, and location of transmission lines in SPRINGFIELD UTILITY BOARD Petition for

Certificate of Public Convenience and Necessity Public Utility Commission of Oregon Docket No. PCN 3.

- Baumgartner Law, LLC, Denver, CO, 2018
  Retained as an expert witness for plaintiffs re calculation of economic harm due to injury in re Eric Bowman, v. Top Tier Colorado, LLC., Case No. 18CV31359, United States District Court, District of Colorado.
- Cohen Milstein Sellers & Toll PLLC, Washington DC, 2018
  Retained as an expert witness for plaintiffs re calculation of economic harm due to breach of contract in re Isaac Harris et al. v. Medical Transportation Management, Inc., Civil Action No. 17-1371, United States District Court, District of Columbia.
- Davison Van Cleve, PC, Portland, OR 2020
  Retained as an expert witness for Alliance of Western Energy Consumers regarding depreciation rates in re PacifiCorp Application for Authority to Implement Revised Depreciation Rates, Public Utility Commission of Oregon Docket No. UM 1968.
- Davison Van Cleve, PC, Salem, OR and Washington Attorney General, OR 2020
  Retained as an expert witness for Packaging Company of America and Washington Public Council regarding depreciation rates in re Pacific Power 2018 Depreciation Study, Washington Utility and Transportation Commission, Docket No. UE-180778.
- Hagens Berman Sobol Shapiro LLP, Phoenix, Arizona, 2018
  Deposed as an expert witness for plaintiffs re calculation of economic harm due to breach of contract in re Vicky Maldonado and Carter v. Apple Inc., AppleCare Services Company, Inc., and Apple CSC, Inc., Case No. 3:16-cv-04067-WHO, United States District Court, District of California.
- Hagens Berman Sobol Shapiro, LLP, Phoenix, Arizona, 2018
  Deposed and testified as an expert witness for plaintiffs re calculation of unpaid mileage for truck drivers in re Swift Transportation Co., Inc., Civil Action No. CV2004-001777, Superior Court of the State of Arizona, County of Maricopa.
- Killmer, Lane, and Newman, LLP, Denver, Colorado, 2018
  Retained as expert witness for plaintiffs re reasonable attorney fees in re Jeanne Stroup and Ruben Lee, v. United Airlines, Inc., Case No. 15-cv-01389-WYD-STV, United States District Court, District of Colorado.
- Klein and Frank, PC, Denver, Colorado, 2018
  Retained as expert witness for plaintiffs re potential jury bias in re Gail Goehrig and Chris Goehrig v. Core Mountain Enterprises, LLC, Case No. 2016CV030004, San Juan County District Court.
- Robert Belluso, Pennsylvania, 2017
  Retained as expert witness for plaintiff re lost profit in re Robert Belluso D.O. v Trustees of Charleroi Community Park, PHRC Case No. 201505365, Pennsylvania Human Relations Commission.
- Lowery Parady, LLC, Denver, Colorado, 2017
  Analyzed payroll data and calculated unpaid overtime and unpaid hours for plaintiff class action in re Violeta Solis, et al. v. The Circle Group, LLC, et al., Case No. 1:16-cv-01329-RBJ, United States District Court, District of Colorado.
- Sawaya & Miller Law Firm, Denver, Colorado, 2017
  Provided data processing and analysis of employment records.

- Financial Scholars Group, Orinda, California, 2017
  Provided analysis of risk profile in bundled real estate and personal loans in re Old Republic Insurance Company v. Countrywide Bank et al., Circuit Court of Cook County, Illinois, Chancery Division.
- Financial Scholars Group, Orinda, California, 2017
  Provided consultation and analysis of financial market transactions in preparation of settlement claims filings in re Laydon v. Mizuho Bank, Ltd., et al. and Sonterra Capital Master Fund Ltd., et al v. UBS AG et al.
- Clean Energy Action, Boulder, Colorado, 2016 – 2017
  Provided consultation on the appropriate discounting methodology used in energy resource planning in the Public Service Company of Colorado application for approval of the 2016 Electric Resource Plan, Proceeding No. 16A-0396E, Public Utilities Commission of the State of Colorado.
- Confidential Client, 2016
  Provided analysis and report on the probability that distinct crimes are independent events based on geographical analysis of crime rates.
- Christine Lamb and Kevin James Burns, Denver, Colorado, 2016
  Provided data analysis for defendant of the impact of ethnicity on termination decisions in re Aragon et al v. Home Depot USA, Inc., Case No. 1:15-cv- 00466-MCA-KK, United States District Court, District of New Mexico.
- Steptoe & Johnson LLP, Washington, DC, 2015 – 2016
  Programmed analysis of internet traffic data for plaintiffs applying a proprietary probability model developed to identify and verify accounts responsible for repeated infringements of asserted copyrights by defendants' internet subscribers in re BMG Rights Management (US) LLC, and Round Hill Music LP v. Cox Enterprises, Inc., et al., Case No. 1:14-cv-1611(LOG/JFA), United States District Court Eastern District of Virginia, Alexandria Division.
- Padilla & Padilla, PLLC, Denver, Colorado, 2014 – 2016
  Provided research and analysis for plaintiffs re the impact on minority applicants from use of the AccuPlacer Test by the City and County of Denver, and estimated damages in re Marian G. Kerner et al. v. City and County of Denver, Civil Action No. 11-cv-00256-MSK-KMT, United States District Court, District of Colorado.
- U.S. Equal Employment Opportunity Commission, 2013
  Provided statistical analysis of EEOC filings.

OTHER REGULATORY PROCEEDINGS:

- Portland General Electric 2016 Annual Power Cost Variance Docket No. UE 329.
- PacifiCorp 2016 Power Cost Adjustment Mechanism Docket No. UE 327.
- Public Utility Commission of Oregon Staff Investigation into the Treatment of New Facility Direct Access Charges Docket No. UM 1837
- PacifiCorp Oregon Specific Cost Allocation Investigation Docket No. UM 1824.
- PacifiCorp 2018 Transition Adjustment Mechanism Docket No. UE 323.
- Portland General Electric 2018 General Rate Case Docket No. UE 319.
- Avista Corp. 2017 General Rate Case Docket No. UG 325.

- Portland General Electric Affiliated Interest Agreement with Portland General Gas Supply Docket No. UI 376.
- Portland General Electric 2017 Automated Update Tariff Docket No. UE 308
- PacifiCorp 2017 Transition Adjustment Mechanism Docket No. UE 307
- Portland General Electric 2017 Reauthorization of Decoupling Adjustment Docket No. UE 306
- Northwest Natural Gas Investigation of WARM Program Docket No. UM 1750.
- PacifiCorp Investigation into Multi-Jurisdictional Allocation Issues Docket No. UM 1050.
- Idaho Power Company 2015 Power Supply Expense True Up Docket No. UE 305
- Homer Electric Association 2015 Depreciation Study U-15-094
- Submitted prefiled testimony regarding the depreciation study.
- Chugach Electric Association 2015 Rate Case U-15-081
- Developed staff position regarding margin calculations.
- ENSTAR 2014 Rate Case U-14-111
- Submitted prefiled testimony regarding sales forecast.
- Alaska Pacific Environmental Services 2014 Rate Case U-14-114/115/116/117/118
  Submitted prefiled testimony regarding cost allocations, cost of service, cost of capital, affiliated interests, and depreciation.
- Alaska Waste 2014 Rate Case U-14-104/105/106/107
  Submitted prefiled testimony regarding cost of service study, cost of capital, operating ratio, and affiliated interest real estate contracts.
- Fairbanks Natural Gas 2014 Rate Case U-14-102
  Submitted prefiled testimony regarding cost of service study and forecasting models.
- Avista 2015 Rate Case U-14-104
  Submitted analysis supporting OPUC Staff settlement positions regarding Avista's sales and load forecast, decoupling mechanisms and interstate cost allocation methodology. Represented Staff in settlement conferences on November 21, November 26, and December 4, 2013.
- Portland General Electric 2015 Rate Case
  Submitted pre-filed opening testimony addressing PGE's sales forecast, printing and mailing budget forecast, mailing budget, marginal cost study, line extension policy and reactive demand charge. Represented OPUC Staff in settlement conferences on May 20, May 27, and June 12, 2014.
- Portland General Electric 2014 General Rate Case
  Submitted analysis supporting OPUC Staff settlement positions regarding PGE's sales and load forecast, revenue decoupling mechanism, and cost of service study. Represented OPUC Staff in settlement conferences on May 29, June 3, June 6, July 2, and July 9 of 2013. Submitted testimony in support of partial stipulation, pre-filed opening testimony addressing PGE's decoupling mechanism, and testimony in support of a second partial stipulation.
- PacifiCorp 2014 General Electric Rate Case
  Submitted analysis supporting OPUC Staff settlement positions regarding PacifiCorp's sales and load forecast and cost of service study. Represented Staff in settlement conferences on June 12 through June 14, 2013.

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UE 416

In the Matters of	)
	)
PORTLAND GENERAL ELECTRIC COMPANY,	)
	)
	)
Request for a General Rate Revision.	)
	)

EXHIBIT AWEC/302

PGE DISCOVERY RESPONSES

(REDACTED)

March 27, 2023

To: Jesse Gorsuch
Alliance of Western Energy Consumers

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 416
PGE Response to AWEC Data Request 047
Dated March 13, 2023

Request:

Please provide workpapers supporting PGE's capital forecast used in this proceeding beginning with actual plant balances and including monthly, project level capital additions in the same format as PGE Response to AWEC Data Request 104 in Docket No UE 394. Please also detail any retirements, transfers or other adjustments applied when developing the forecast. Finally, please also demonstrate how the forecast ties to the hardcoded $12,253,120,543 gross plant balance identified in workpaper "Exhibit Support_ 2024" Tab "Rate Base Data," Cell "C11."

Response:

Attachment 047-A provides forecasted project level plant additions. Total forecasted plant additions are $916,742,328 for 2023. For reconciliation and roll forward of actual plant balances as of 12/31/2022 to the forecasted plant balance as of 12/31/2023, refer to tab "Net Plant Recon Detailed" of PGE's response to AWEC Data Request No. 039, Attachment 039-A. For forecasted plant retirements, refer to tab "2023 FCST Plant Activity - Ret" of PGE's response to AWEC Data Request No. 039, Attachment 039-A.

Project	Total
P36167 - FY: Repower Faraday Units 1-5	188,067,480
P37218 - OH FITNES Distribution	108,334,383
P37346 - powERPlay	37,595,820
P36836 - BR: Beaver Modernization	35,747,276
P36679 - Orenco Substation 115kV Rebuild	29,208,111
P37272 - Oracle Utilities Upgrade	22,575,684
P36394 - Vintage Vehicle Replacement II	18,777,608
P36501 - Integrated Operations Center - IOC	18,692,709
P14628 - Replace Failed Underground Cables	15,346,000
P35924 - Distribution System Construction II	14,169,775
P37048 - Outage or Emergency Replacement	13,207,291
P35890 - Purchase Distribution Transformers	12,733,049
P37344 - Tech Refresh	12,603,008
P36134 - Hydro Control System Upgrade	11,913,714
P36770 - Street and Area Light Construction	11,148,325
P37160 - Helvetia Substation Phase 2	10,879,955
P37312 - Digital Channel Uplift 22	10,774,324
P36522 - Distribution Automation	10,142,329

May 9, 2023

To: Jesse Gorsuch
Alliance of Western Energy Consumers

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 416
PGE Response to AWEC Data Request 058
Dated March 13, 2023

Request:

Please provide all correspondence between PGE and the contractors that performed services with respect to the Faraday Repowering Project between 2014 and the most recent month available.

Response:

PGE objects to this request on the basis that it is vague, overly broad, and unduly burdensome. Subject to and without waiving this objection, PGE responds as follows:

Confidential Attachment 058-A provides email communication between PGE and general contractors that performed work at the Faraday Resiliency and Repowering Project for the period between January 2018 and present.

PGE's initial communication retrieval from PGE's archive resulted in more than 150,000 documents, which was administratively burdensome to process and review. PGE further refined the communication parameters to only include email communication between PGE project managers and personnel directly related to the Faraday Resiliency and Repowering Project and representatives from the two general contractors hired to manage the project construction. PGE also removed non-responsive emails, lesser included emails (i.e., emails that are already part of a larger email communication string), and also used terms to identify email communication directly related to the Faraday Resiliency and Repowering Project. The refinement reduced the amount of communication to approximately 860 emails, which was still burdensome, but we were ultimately able to process and review.

Attachment 058-A is protected information subject to Protective Order No. 23-039.

[redacted]

March 27, 2023

To: Jesse Gorsuch
Alliance of Western Energy Consumers

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 416
PGE Response to AWEC Data Request 059
Dated March 13, 2023

Request:

Please provide all economic analyses that PGE performed to justify commencing with the Faraday Repowering project, and any subsequent analyses that PGE conducted to demonstrate the continued economics of the project.

Response:

PGE objects to this data request on the basis that it assumes that economics was the primary reason to justify PGE starting the Faraday Resiliency and Repowering Project. Without waiving this objection, PGE responds as follows:

As described in PGE Exhibit 800, Section V.D, a seismic evaluation performed in 2014 by an outside engineering expert found the 1907 Faraday Powerhouse seismically unfit and a "hazardous structure when considering its lack of reliable resistance to earthquake ground motions."[1] Additionally, the 1907 Faraday Powerhouse was at increased risk of non-operations and flooding during high river flow events while also numerous pieces of plant equipment had exceeded their useful lives, including the generating turbines. To address these issues and maintain the plant in safe and reliable operating conditions, PGE made the decision to pursue the Faraday Resiliency and Repowering Project. As with other capital projects, PGE performed economic analyses before the start of the project and as the project progressed. However, while economic factors were considered in the review of available options prior to the start of the project, PGE's decision to move forward with the Faraday Resiliency and Repowering Project also prioritized maintaining PGE's ability to safely and reliably operate Faraday while continuing to provide clean and sustainable energy benefits to customers.

Confidential Attachment 059-A provides the:

- 2016 economic analysis performed prior to the start of the Faraday Resiliency and Repowering Project.
- 2019 economic analysis performed after PGE received bids from contractors.
- 2020 economic analysis performed after project costs were updated due to construction

[1] *See* Exhibit 805, Section III. Recommendations, paragraph A, pg. 4.

schedule delays.
- 2023 economic analysis performed after the project transitioned to the new general contractor.

Please note that the actual project costs were updated as part of the economic analyses at four different stages in the progression of project development. However, as the construction project progressed, the estimated costs associated with pursuing alternatives to address the issues identified at Faraday assumed no extraordinary event would impact those assessments. It is reasonable, however, to assume that other alternatives would have also been impacted by the numerous events outside of PGE’s control that resulted in cost updates for the Faraday Resiliency and Repowering Project.

Attachment 059-A is protected information subject to Protective Order No. 23-039.

Protected Information Subject to
Modified General Protective Order

[redacted]

[redacted]

[redacted]

April 20, 2023

To: Jesse Gorsuch
Alliance of Western Energy Consumers

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 416
PGE Response to AWEC Data Request 061
Dated March 13, 2023

Request:

Please provide all presentations to PGE's board of directors regarding Faraday Repowering Project over the period 2014 thought the most recent month available.

Response:

Confidential Attachment 061-A provides presentation and minutes to PGE's board of directors that included detail regarding the Faraday Resiliency and Repowering Project for the period between January 1, 2016 and February 2023.

Attachment 061-A is protected information subject to Protective Order No. 23-039.

Pages 11 – 21 of Exhibit AWEC/302 contain Protected Information Subject to Modified General Protective Order No. 23-039 and have been redacted in their entirety.

April 24, 2023

To: Jesse Gorsuch
Alliance of Western Energy Consumers

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 416
PGE Response to AWEC Data Request 158
Dated April 10, 2023

Request:

Reference PGE/800 at 3:8-9:

a. Please provide all economic analysis and project justification documentation supporting the referenced investment in Beaver Modernization.

b. Are the new turbines at Beaver more efficient than the old ones? If yes, please quantify the efficiency gains. If no, please explain.

c. Do the new turbines at Beaver have a different cycling profile than the old turbines? If yes, please describe the new cycling profiles. If no, please explain.

d. Please provide all OEM documentation supporting characteristics and operation of the upgraded turbine equipment.

e. Please identify all plant retirements associated with the modernization investment.

f. Please identify all salvage associated with the modernization investment.

Response:

a. Confidential Attachment 158-A provides the project justification for the Beaver Modernization Project. Confidential Attachment 158-B provides the economic analysis conducted for the Beaver Modernization Project. We note that the primary justification for this project is related to environmental upgrades. Beaver is subject to the Oregon Department of Environmental Quality's (ODEQ) enforcement of the Regional Haze Program, which implements the federal Clean Air Act's Regional Haze Rule. In August 2021, ODEQ issued an order requiring PGE's compliance with annual plant site emissions limits of Regional Haze pollutants. To keep Beaver operating as an important part of PGE's generation portfolio, and to avoid incurring ODEQ penalties, the Beaver plant needed to be modernized to reduce NOx emissions.
b. The turbines at Beaver are not being replaced; they are being overhauled to return to like-new condition. While the purpose of this combustion system being modernized is to reduce

NOX, emissions, the first turbine modernization did show efficiency gains in the form of a heat rate reduction for the turbine. [START HIGHLY CONFIDENTIAL] [redacted] END HIGHLY CONFIDENTIAL]

c. The cycling profile is not being changed by this combustion system upgrade. Beaver dispatch is determined by PGE's power operations, based on economic dispatch.
d. Highly Confidential Attachment 158-C provides the PSM model data for the combustion system upgrade. We note that while these model results show an increase in capacity, but due to statutory requirements regarding facilities without site certificates from the Energy Facility Siting Council (EFSC), operational controls are on the units to ensure that they do not run in a fashion that would result in increased capacity of the facility.
e. There have been no plant retirements yet identified for the Beaver Modernization Project.
f. Attachment 158-D provides receipt of all salvage associated with the Beaver Modernization Project. The salvage total is $90,000.

PGE's response to AWEC Data Request No. 158 is protected information subject to Modified Protective Order No. 23-138.

Attachments 158-A and 158-B are protected information subject to Protective Order No. 23-039.

Attachment 158-C is highly confidential information subject to Modified Protective Order No. 23-138.

[redacted]

[redacted]

[redacted]

May 9, 2023

To: Jesse Gorsuch
Alliance of Western Energy Consumers

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 416
PGE Response to AWEC Data Request 190
Dated April 25, 2023

Request:

Please refer to “UE 416_OPUC SDR 057_Attach A_CONF.xlsx”. Please identify all fleet fuel purchases in this sheet.

Response:

Fleet fuel is charged to account 1840001 and then allocated to both balance sheet and income statement accounts through PGE’s transportation allocation. Confidential Attachment 190-A provides transaction level detail for fleet fuel purchases recorded to account 1840001. In order to determine the amount of fleet fuel purchases allocated to amounts included in PGE’s response to OPUC Standard Data Request No. 057, Attachment 057-A, the ratio of PGE’s transportation allocation applied to the accounts included in Attachment 057-A must be ratably applied to the total amount fleet fuel purchases included in account 1840001. Attachment 190-B provides fleet fuel amounts allocated to operations and maintenance accounts, by account, for 2022 actuals and the 2024 test year forecast. Additionally, a small amount ($631.93) was recorded directly to O&M accounts included in Attachment 057-A. These amounts can be identified by the accounting work order (AWO) number 3000000170.

UE 416
PGE's Response to AWEC DR 190
Attachment B

Fleet Fuel Allocated to 500-935

Account	2022 Act	2024 GRC
5350001	$ 558.77	$ -
5430001	$ 15.60	$ -
5440001	$ 2,429.93	$ -
5450001	$ 3,791.66	$ -
5450003	$ 165.17	$ -
5460001	$ 21.26	$ -
5490001	$ 281.85	$ -
5520001	$ 202.77	$ -
5530001	$ 8,322.25	$ -
5540001	$ 8,015.13	$ -
5600001	$ 605.85	$ -
5600038	$ 33,094.83	$ -
5620001	$ 16,848.15	$ -
5630001	$ 8,727.07	$ 11,112.84
5630002	$ 5,715.55	$ 17,780.53
5630003	$ 804.68	$ -
5700001	$ 28,473.55	$ 83,148.49
5710001	$ 4,996.80	$ 4,034.64
5710002	$ 5,763.28	$ 4,034.64
5710003	$ 52.99	$ -
5710004	$ 313.95	$ -
5710099	$ 473.26	$ -
5800002	$ 265,661.35	$ 503,064.00
5800038	$ 127,818.64	$ 144,182.71
5810001	$ 1,586.46	$ -
5820001	$ 13,738.52	$ -
5820002	$ 8,843.86	$ -
5820005	$ 28,553.85	$ 28,303.62
5830001	$ 44,964.44	$ 46,898.93
5830002	$ 28.65	$ -
5840001	$ 27,100.50	$ 61,355.62
5840002	$ 80.79	$ -
5850001	$ 2,320.78	$ -
5850002	$ 3,867.07	$ -
5860001	$ 119,377.91	$ 79,622.03
5870001	$ 83,934.40	$ 68,355.46
5880001	$ 47,334.85	$ 263,896.06
5900001	$ 992.01	$ -
5910001	$ 623.62	$ -
5920001	$ 125,078.05	$ 176,077.08
5920002	$ 6,199.04	$ -
5922001	$ 620.09	$ -
5930001	$ 534,549.01	$ 416,795.03
5930099	$ 10,739.90	$ -

UE 416
PGE's Response to AWEC DR 190
Attachment B

5940001	$ 153,610.41	$ 185,016.73
5940099	$ 33.64	$ -
5950001	$ 6.15	$ -
5960001	$ 9,414.76	$ 11,682.80
5970001	$ 128.99	$ 73,340.46
5980001	$ 26.84	$ -
9030001	$ 2,284.61	$ 14,074.84
9080001	$ 236.99	$ -
9250001	$ 150.24	$ -
9302001	$ 561.60	$ -
9350001	$ 30,225.08	$ -
	$ 1,780,367.45	$ 2,192,776.52

May 9, 2023

To: Jesse Gorsuch
Alliance of Western Energy Consumers

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 416
PGE Response to AWEC Data Request 206
Dated April 25, 2023

Request:

Please refer to PGE / 800, Jenkins – Bekkedahl / 3.

a. Please provide annual plant site emissions for Beaver, Port Westward, Port Westward II, and Carty from 2018 to present.
b. Please provide annual generation by plant for Beaver, Port Westward, Port Westward II, and Carty from 2018 to present.
c. Please provide annual plant site emissions for the Boardman plant from 2016 to 2020.
d. Please provide annual generation for the Boardman plant from 2016 to 2020.
e. Did PGE perform a four-factors analysis described in OAR 340-223-0120? If yes, please provide such analysis. If no, why not?
f. What alternatives did PGE consider to meet the stipulated emissions amounts?
g. Is it PGE's belief that the Beaver Emissions Reductions Program is cost effective, or would be deemed cost effective if it had been evaluated by Oregon DEQ pursuant to OAR 340-223-0110? If yes, please provide the basis for this belief.
h. Please provide all comments submitted by PGE related to Oregon DEQ's round 2 regional haze SIP.
i. Please provide the project approval and all project management documents related to the Beaver Emissions Reduction Program.

Response:

a. Attachment 206-A provides annual plant site emissions for Beaver, Port Westward, Port Westward II, and Carty from 2018 to present.
b. Confidential Attachment 206-B provides annual generation by plant for Beaver, Port Westward, Port Westward II, and Carty from 2018 to present.
c. Attachment 206-A provides annual plant site emissions for the Boardman plant from 2016 to 2020.
d. Confidential Attachment 206-B provides annual generation for the Boardman plant from 2016 to 2020
e. To comply with DEQ's Regional Haze Round 2 efforts, PGE negotiated a reduction in

allowable emissions from Beaver and Port Westward resulting in an enforceable order codifying the reduction in Plant Site Emissions Limits. This approach met DEQ requirements for Regional Haze without requiring the timely, costly, and potentially uncertain outcomes of a four-factor analysis. It also provides PGE the greatest flexibility in determining a least cost, least risk approach to meeting the emissions reductions requirements.

f. PGE considered several options to address emissions reductions. Those are full repower, a Selective Catalytic Reduction (SCR) addition, and a combustion system upgrade. A full repower of the plant would have a significant cost and the existing Beaver turbines have remaining life. The Beaver Heat Recover Steam Generators are vertical flow with no available space to install an SCR. Therefore, the combustion system upgrade was the best option to address emissions reductions and utilize the remaining life of the Beaver combustion turbines.

   For the combustion system technology itself, PGE contacted other utilities and discussed technologies with potential suppliers. An RFP was issued to 3 suppliers that were identified as potentially being able to support a combustion system upgrade on older, vintage GE combustion turbines. The selected supplier was the only bidder that proposed a fully designed combustion system upgrade with industry operating experience.

g. PGE objects to this request on the basis that the question calls for speculation. Without waiving this objection, PGE responds as follows:

   A four-factor analysis is a complex and iterative process that can include back and forth discussions and negotiations with DEQ surrounding assumptions and inputs into the analysis. PGE cannot predict the outcome of a regulatory process that allows for DEQ interpretation and regulatory discretion. PGE’s approach to navigating the regulatory requirements of Regional Haze did not require a four-factor analysis and so none was performed.

h. PGE did not provide public comment on the Regional Haze round 2 SIP.

i. PGE objects to this request on the basis that it is vague and overly broad. Notwithstanding its objection, PGE responds as follows:

   The previously submitted Confidential Attachment 158-A provides the currently approved project justification form. If there are any specific additional documents that AWEC would like to see, that have not already been provided in data requests, please let PGE know.

   Attachments 206-A and 206-B are protected information subject to Protective Order No. 23-039.

UE 416 AWEC DR 206
Attachment 206-B CONF

[redacted]

Attachment 206-B is protected information subject to Protective Order No. 23-039.

May 9, 2023

To: Jesse Gorsuch
Alliance of Western Energy Consumers

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 416
PGE Response to AWEC Data Request 212
Dated April 25, 2023

Request:

Please refer to PGE / 800 Jenkins – Bekkedahl / 3 which states that the Beaver Emissions Reduction Program "will modernize the turbines, extending their life." Please provide the expected life of the Beaver units before and after modernization.

Response:

The main goal of the Beaver Emissions Reduction Program is to reduce emissions in accordance with the ODEQ requirements. This modernization will also extend the life of Beaver to 2040. Beaver has become more important as a peaking and reliability resource to help integrate additional renewables and ensure this is done reliably. Prior to this Program, the goal was to ensure Beaver's operation to 2030.

May 9, 2023

To: Jesse Gorsuch
Alliance of Western Energy Consumers

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 416
PGE Response to AWEC Data Request 214
Dated April 25, 2023

Request:

Please refer to PGE / 200 Batzler - Ferchland / 10.

a. Is it PGE's intention to calculate 2024 depreciation expense limited to plant in service on December 31, 2023? If no, please explain the measure that PGE intends to use for test year depreciation expense.
b. Is PGE recording actual 2023 depreciation expense for Faraday using approved depreciation rates or proposed depreciation rates?
c. Is it PGE's intention to calculate average annual rate base in 2024 limited to plant in service on December 31, 2023? If no, please explain the measure of rate base that PGE intends to use for the test year.
d. Please explain why PGE believes its measure of rate base is consistent with its measure of depreciation expense and accumulated depreciation.

Response:

a. Yes.
b. For 2023, PGE is using approved depreciation parameters for the Faraday Hydro Plant.
c. PGE is not calculating average annual rate base. As stated in PGE Exhibit 200, Sections I and VI, PGE established its rate base balances as of December 31, 2023.
d. PGE's calculation of depreciation expense and how it aligns with PGE's rate base balance is described in PGE Exhibit 200, Section III.

May 10, 2023

To: Jesse Gorsuch
Alliance of Western Energy Consumers

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 416
PGE Response to AWEC Data Request 231
Dated April 26, 2023

Request:

Please refer to PGE's Response to AWEC DR 055.

a. Please identify the impact of each major event on the Faraday Resiliency and Repowering Project.
b. Please provide the date, flood levels, and stream flows for each flood event.

Response:

PGE objects to this request on the basis that it is vague and overly broad. Subject to and without waiving this objection, PGE responds as follows:

a. See PGE Exhibit 800, Section V.E, at 42-45.

b. The high Clackamas River stream flows for the dates when the Faraday Resiliency and Repowering Project site was flooded were:

- 2020-01-11: 6,130 cfs
- 2020-12-20: 20,900 cfs
- 2021-01-13: 31,000 cfs

PGE’s Emergency Action Plan (EAP) for hydro operations on the Clackamas River provides for the following flood levels, as determined for the Clackamas River potential downstream impacts to the public:

- 22,500 cfs – Initial Contact for EAP entry
- 27,600 cfs – Widespread Flooding
- 35,000 cfs – Sever Flooding

Please note that the river flows when the Faraday Resiliency and Repowering Project site was flooded do not correlate with the Clackamas River flood levels provided above because of the cofferdam built to allow in-water work. The cofferdam constricted the river channel from approximately 200 feet wide to approximately 100 feet wide. The constriction significantly increased the velocity and elevation of the water in the river channel during high flow events, causing the flooding of the Faraday Resiliency and Repowering Project site in January and December 2020, and January 2021.

May 9, 2023

To: Jesse Gorsuch
Alliance of Western Energy Consumers

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 416
PGE Response to AWEC Data Request 236
Dated April 25, 2023

Request:

Please refer to PGE / 800 Jenkins – Bekkedahl / 44. Please provide all documents associated with the termination of the initial general contractor.

Response:

PGE objects to this request on the basis that it draws incorrect conclusions. PGE and the original contractor executed an amendment to the contract that resulted in amiable separation. Subject to and without waiving this objection PGE responds as follows:

Confidential Attachment 236-A provides the contract amendment between PGE and the original contractor that resulted in separation.

Attachment 236-A is protected information subject to Protective Order No. 23-039.

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

1 of 2

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

May 12, 2023

To: Jesse Gorsuch
Alliance of Western Energy Consumers

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 416
PGE Response to AWEC Data Request 245
Dated April 28, 2023

Request:

Please refer to PGE workpaper "2024 Customer Marginal Cost."

a. Please refer to sheet "Billing 2024" row 12 which shows amounts from 9030001 for Business Customer Contact Ops. Please also refer to "2024 Unbundled ROO" sheet "Unbundled" which shows these amounts are unbundled to consumer rather than billing. Please provide the reason for not allocating these amounts in the "Other 2024" sheet rather than the "Billing 2024" sheet.
b. Please provide the same information in part a for account 9030001 dept. 404: Customer Services Ops Admin.
c. Please provide the same information in part a for account 9030001 for Customer Contact Operations.
d. Please provide the same information in part a for account 9030001 dept. 472: OPS Performance Solutions
e. Please provide the same information in part a for account 9050001 dept. 555: VP, Customer Solutions. Please note that while the sheet "Billing 2024" has no amounts for this account, the sheet "Unbundled" shows amounts unbundled to other consumer.
f. Please provide the same information in part a for account 9030001 and account 9080001 Dept. 567: Customer Digital Channels. Please note that while sheet "Billing 2024" only has these amounts for account 9030001, both account 9030001 and 9080001 have amounts unbundled to other consumer.
g. Please refer to sheet "Other 2024" row 11 which shows amounts from 9050001 for Customer Contact Operations are allocated to customers. Please also refer to "2024 Unbundled ROO" sheet "Unbundled" which shows amounts for 9030001 for Customer Contact Operations unbundled to other consumer. Please provide the reason for not allocating the amounts for 9030001 for Customer Contact Operations in the same manner as those for account 9050001.

Response:

a. Generally, FERC account 903 refers to customer records and collection expenses and as such, activities charged to this account are related to billing or other consumer activities. Historically, the customer marginal cost study has allocated account 903, with the exception of department 527, to billing activities as it is argued that many of these activities are related to billing. For cost unbundling purposes, PGE follows OAR 860-038-0200, which in addition to defining the functional categories, states that costs must be directly assigned where information is available. As such, PGE’s cost unbundling looks directly at departments to unbundle this account. OAR 860-038-0200 also states that “[t]he calculation of unbundled rates is beyond the scope of this rule.”
b. See PGE’s response to part a.
c. See PGE’s response to part a.
d. See PGE’s response to part a.
e. Account 9050001 department 555 was inadvertently excluded from the customer marginal cost study as account 9030001 department 555 was included and did not have any dollar amounts associated.
f. Account 9080001 was inadvertently excluded from the Other 2024 tab. For account 9030001, see PGE’s response to part a.
g. See PGE’s response to part a. FERC account 905 is related to miscellaneous customer accounts expenses, where account 903 is related to customer records and collection expenses and is subject to interpretation as to if the expenses are directly attributable to billing or other consumer.

May 12, 2023

To: Jesse Gorsuch
Alliance of Western Energy Consumers

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 416
PGE Response to AWEC Data Request 249
Dated April 28, 2023

Request:

Please refer to 2024 Generation Marginal Cost_CONF.xlsx sheet Battery.

a. Please refer to cells C25 through C29. Please provide references to PGE's final IRP supporting these numbers or updated numbers.

b. Please refer to column L. Please provide the source of these values and explain why these values represent a reduction to revenue requirement.

c. Please refer to PGE's 2023 IRP page 553. Please identify the number of MW of added nameplate capacity used to select the battery ELCC in this sheet and explain why this level of added capacity was used in the model.

Response:

a. These inputs used to model the marginal cost of capacity drew from draft inputs used in PGE's 2023 Clean Energy Plan and Integrated Resource Plan (CEP & IRP), with the exception of the effective load carrying capability (ELCC). A separate run of PGE's Sequoia model was used to estimate the ELCC of a 4-hour battery using a 2024 deficiency year. The resource supply gaps in 2024 are fewer and more concentrated in summer evening hours, resulting in an increased relative capacity contribution of battery storage resources. The ELCCs published in PGE's CEP & IRP reflects a 2026 deficiency year with a wider range of deficient hours and yield lower relative battery storage contributions. Table 50 in PGE's 2023 CEP & IRP indicates an ELCC of 69% during summer months and 44% during winter months, averaging 57% overall.

   The discrepancy in salvage value reflects a manual error in the marginal cost study input and will be corrected in PGE's reply testimony. See PGE's response to UE 416 OPUC DR 480 (e), which explains that decommissioning costs for batteries are estimated at -0.5% of overnight capital costs, per the external study conducted by HDR, Inc for the 2019 IRP (page 562).

The overnight capital cost for a 4-hour battery published in the 2023 CEP & IRP is $1,189 in $2023 (Table 33), which converts to $1,214 $2024 using a 2.13% average inflation rate.

Row	Input	Marginal Cost Study	CEP/IRP
25	ELCC	83%	57%
26	Availability Factor	97%	97%
27	Economic Life	20	20
28	Salvage Value	-5%	-0.5%
29	Overnight Capital (2024 $/kW)	$1,195	$1,214

b. Negative wheeling costs were inadvertently included when estimating the levelized annual value of a 4-hour battery resource. There should not be any wheeling costs modeled for battery storage resources and this adjustment will be made in PGE's reply testimony.

c. PGE models ELCC values per 100 MW increments of added nameplate capacity for system resources. Given that the nameplate capacity of the proxy 4-hour battery storage resource used in the generation marginal cost study is only 50 MW, the 100 MW ELCC is the closest approximation.

May 12, 2023

To: Jesse Gorsuch
Alliance of Western Energy Consumers

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 416
PGE Response to AWEC Data Request 252
Dated April 28, 2023

Request:

Please refer to PGE's 2023 IRP, page 244.

a. Please reconcile the cost of capacity calculated on this page with that calculated in 2024 Generation Marginal Cost_CONF.xlsx.
b. The referenced page states that the preferred portfolio selects 232 MW of storage. Please also refer to page 289. The preferred portfolio appears to select 400 MW of storage in 2025 and 232 additional MW of storage in 2026. Please reconcile these two pages and provide the ELCC of 632 MW of incremental 4-hour batteries.

Response:

a. At a high-level, the net cost of capacity for a 4-hour battery resource shown in Figure 72 of PGE's 2023 Clean Energy Plan and Integrated Resource Plan (CEP & IRP) is similar to that modeled in PGE's generation marginal cost study in UE 416 Exhibit 1200.

	2023 CEP & IRP	Marginal Cost Study
$2023	$144/kW-yr	
$2024	$147/kW-yr	$139/kW-yr

The marginal cost study takes a simplified approach to modeling and uses 2024 for commercial operation date (COD) and deficiency year. Costs presented in the 2023 CEP & IRP assume 2026 for both and include more nuanced modeling and slightly different economic assumptions. For these reasons, the interim estimates that comprise the annual levelized capacity costs in each application differ; however, the overall cost estimates are similar.

b. Table 64 on page 289 of PGE's 2023 CEP & IRP includes resources added in the Preferred Portfolio (232 MW of 4-hour battery online in 2026) as well as, for informational purposes, the resources assumed to be acquired in the 2021 All-Source RFP (which includes 400 MW of 4-hour battery online in 2025). The explanation on page 244 refers to the Preferred Portfolio's storage additions (232

MW) while assuming the All-Source RFP resources are already acquired as well. The ELCC values presented in the Generation Marginal Cost study reflect PGE's system before the 632 MW of 4-hour battery additions.

June 8, 2023

To: Jesse Gorsuch
Alliance of Western Energy Consumers

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 416
PGE Response to AWEC Data Request 278
Dated May 25, 2023

Request:

Please refer to the response to AWEC DR 206, part e.

a. Please provide the annual emissions limits that Beaver is subject to. If multiple plants contribute to these limits, please identify all plants that are subject to the limit.
b. Please provide PGE's initial settlement proposal, and ODOE's initial settlement proposal.
c. Did PGE attempt to secure a trade-off between emission types, such as reduced limits on SO2 in exchange for increased limits on NOX? If no, why not? If yes, what was the request and ODOE's response?
d. Have the plants subject to the emission limits in part a ever exceeded the annual emission amounts identified in part a? If yes, please provide the years and emissions amounts.
e. Did PGE prepare a budget, estimate costs, or otherwise evaluate the costs of performing a four-factor analysis? If yes, provide the costs, budgets, and evaluations. If no, why not?

Response:

a. Beaver's annual emissions are limited by the Title V permit #05-250, which establishes plant site emission limits (PSEL) for Beaver and Port Westward 1 combined. Port Westward 2 emissions are regulated per Standard Air Contaminant Discharge Permit (ACDP) # 05-2606, which PGE expects to be added to the Title V permit when DEQ issues the renewal. Associated emissions from Port Westward 2 will be added to the PSELs but will remain applicable only to Port Westward 2. The Stipulated Agreement and Final Order (SAFO) #05-2606 reduced PSELs for Beaver and Port Westward 1 over a 5-year period for some pollutants starting in August 2021, as follows (emissions reflected in tons per year):

Pollutant	Title V PSEL (Condition 59, Table 6)	Stipulated Agreement and Final Order (SAFO)				
		Year 1 (8/1/21 - 7/31/22)	Year 2 (8/1/22 - 7/31/23)	Year 3 (8/1/23 - 7/31/24)	Year 4 (8/1/24 - 7/31/25)	Year 5 (8/1/25 and later)
PM/PM10	241	99				
CO	1,104	Unchanged by SAFO				
NOx	3,776	1,900	1,542	1,184	826	436
SO2	595	99				39
VOC	118	Unchanged by SAFO				

b. The SAFO was developed between PGE and DEQ beginning in 2020. The Oregon Department of Energy (ODOE) does not regulate emissions and was not a signatory to the agreement. PGE issued a letter of intent on June 15, 2020, proposing reductions in PSELs to achieve emission levels below DEQ's screening levels for the Regional Haze Program. DEQ concurred with the proposed reductions August 13, 2020. The PSELs proposed were identical to those in the SAFO with the exceptions of the Year 5 PSELs for NOx and SO2, which were proposed at 468 and 99 tons, respectively. Those PSELs were reduced to reflect a change in DEQ's screening methodology. Attachment 278-A provides PGE's letter of intent. Attachment 278-B provides DEQ's response to the letter of intent. Attachment 278-C provides the SAFO with agreed emission reductions.

c. SO2 and PM reductions were contemplated and actualized in the SAFO. As a source primarily using natural gas, NOx is the pollutant with the greatest contribution to regional haze. It is also the pollutant for which emissions controls are most readily available and feasible for gas turbines. NOx formation is a function of combustion conditions, and the burner technology selected for the upgrades enabled the NOx reductions in support of compliance with the SAFO. SO2 and PM emissions are directly related to fuel use, and control technologies for the relatively small emissions resulting from gas combustion are not available.

d. No, the emission limits have not been exceeded.

e. PGE did not evaluate the costs of performing a four-factor analysis. As provided for in DEQ's Regional Haze rules, PGE entered into the SAFO in place of this process; a result of electing this method of compliance saved PGE and DEQ from expending resources on the four-factor analysis process. Negotiating the emissions reductions in the SAFO provided PGE the greatest flexibility in determining the appropriate emissions reduction approach, timetable for the reductions and greatest flexibility in determining the implementation schedule.

June 8, 2023

To: Jesse Gorsuch
Alliance of Western Energy Consumers

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 416
PGE Response to AWEC Data Request 279
Dated May 25, 2023

Request:

Please refer to the response to AWEC DR 206, Confidential Attachment A.

a. Please confirm that each row in these data reflects 12 months of emissions.
b. Are regional haze emissions limits evaluated on a rolling 12-month total basis? If not, please detail how regional haze limits are evaluated.

Response:

a. The data reflects 12 months of emissions with the exception of the row "2023 1st Quarter" rows for Carty and Coyote, which reflect the three-month period of January through March 2023. Note that we are replacing the spreadsheet for Beaver and Port Westward (Beaver, PWW 1&2" tab); we identified an error where Beaver's emissions were being double counted by the spreadsheet logic in the previous version and are submitting the corrected spreadsheet as Confidential Attachment 279-A.
b. The emission limits are evaluated on a rolling 12-month basis.

Attachment 279-A is protected information subject to Protective Order No. 23-038.

UE 416 AWEC DR 279
Attach A CONF

[redacted]

Attachment 279-A is protected information subject to Protective Order No. 23-139.

June 8, 2023

To: Jesse Gorsuch
Alliance of Western Energy Consumers

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 416
PGE Response to AWEC Data Request 280
Dated May 25, 2023

Request:

Please refer to the response to AWEC DR, 206, part f.

a. Could PGE have continued to operate the Beaver Plant under its original equipment and complied with emissions limits by limiting the monthly or annual generation of the Beaver Plant such that emissions limits are not exceeded? If no, why not.
b. If the response to part (a), above is yes, did PGE analyze, evaluate or otherwise consider this option? If no, why not? If yes, please provide the results and supporting workpapers.
c. If the response to part (a), above is yes, please provide the maximum average annual generation in MWh that Beaver Plant could operate under its original equipment without exceeding the new emissions limit. If such data require assumptions regarding the generation of other plants, provide the results when 1) assuming that other plants operate at full capacity after derating for average outages and 2) assuming that other plants operate at the highest annual generation of the last 5 years. If PGE declines to provide such data, please provide the information necessary to perform such calculations.
d. Could PGE modify a fewer number of units at the Beaver Plant and still achieve compliance with the new regional haze emissions limits? If no, why not?
e. If the response to part (d), above is yes, did PGE analyze, evaluate or otherwise consider this option? If no, why not? If yes, please provide the results and supporting workpapers.
f. If the response to part (d), above is yes, please provide the minimum number of units that need to be modified to achieve compliance with the new regional haze emissions limits. If PGE declines to provide such data, please provide the information necessary to perform such calculations.

Response:

a. PGE could have reduced operations at the Beaver Plant to comply with the emissions limits but such a reduction would have brought operations to an unreasonably low-capacity factor. The Beaver Plant's full complement of six combustion turbines is needed to provide peaking power generation to balance renewables and meet generation needs during high load periods (e.g., hot weather with associated load from air conditioning). Such periods occur throughout the year and imposing operating restrictions to reduce emissions would risk the ability to provide a reliable electricity service to PGE's customers. This approach would have limited Beaver operations to a capacity factor of 19% annually, to remain emissions compliant. This compares to a 20% capacity factor in 2022, with projected increases each year until 2030.

b. See response to part a. PGE's IRP forecasting has Beaver output in 2023 of 556,936 MWH and projected to increase to 1,330,065 MWH by 2029. This is a 139% increase in energy production to meet the needs for integrating renewables and meeting customer load. Beaver capacity factor in 2022 was 20%. PGE's Power Operations projects Beaver's CF to increase steadily until 2030, under current modeling. Because of this forecasted increase in output at Beaver, the option to reduce operations to meet emissions limits is not feasible.
c. Approximately 850,000 MWh.
d. No. See response to parts a and b. Compliance with the Regional Haze limits is a function of operational needs and emission rates. Based on the forecast generation in the IRP and in consideration of the volatility in demand for peaking generation, all Beaver Turbines must be upgraded in order to remain compliant with the emissions limitations.
e. Not applicable. See responses to parts a and b.
f. Not applicable.

June 8, 2023

To: Jesse Gorsuch
Alliance of Western Energy Consumers

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 416
PGE Response to AWEC Data Request 281
Dated May 25, 2023

Request:

Please refer to the response to AWEC DR 206, part g.

a. Is it PGE's belief that the Beaver Emissions Reductions Program is cost effective? If yes, please provide support for this conclusion.
b. Please provide PGE's understanding of what constitutes cost-effective control under OAR 340-223-0110.

Response:

a. PGE objects to this request on the basis that the question calls for speculation. Without waiving this objection, PGE responds as follows:

   The primary driver of this project was to meet stipulated environmental regulations. Beaver is an important resource for providing safe and reliable power to PGE customers. To ensure Beaver continues to operate in accordance with environmental regulations, PGE is completing the Beaver Emissions Reduction Program. PGE's response to AWEC Data Request 206, part f, explains the evaluation process that PGE conducted to decide upon this course of action. All other options were expected to be significantly more costly, or not possible at all. PGE issued an RFP to suppliers to find the best technology for combustion system emissions reduction. The economic analysis associated with this bidding process is provided as PGE's response to AWEC Data Request 158, Attachment 158-B.

b. PGE objects to this request on the basis that the question calls for a legal conclusion.

June 8, 2023

To: Jesse Gorsuch
Alliance of Western Energy Consumers

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 416
PGE Response to AWEC Data Request 282_CONFIDENTIAL
Dated May 25, 2023

Request:

Please refer to the response to AWEC DR 158, Confidential Attachment A, page 11. This shows an increase in the total budget of [redacted], more than tripling the budget and doubling the total project cost estimate. Did PGE re-evaluate the economic viability of the project at this stage, or reconsider other options? If no, why not? If yes, please provide documentation of such evaluations.

Response:

The initial budget for the project was for the contract for the upgrades for the first two units. PGE's approach was to contract the first two upgrades, allowing flexibility in execution of the remaining upgrades based on initial lessons learned and contractor performance. The significant increase in Revision 99 reflects the remaining four upgrades being included in the project budget.

June 8, 2023

To: Jesse Gorsuch
Alliance of Western Energy Consumers

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 416
PGE Response to AWEC Data Request 283_CONFIDENTIAL
Dated May 25, 2023

Request:

Protected Information
Subject to Modified General Protective Order

Please refer to the response to AWEC DR 212.

a. Please provide the basis for PGE's understanding that the Beaver Emissions Reductions Program will increase the life of the Beaver Plant from 2030 to 2040. Please include documentation supporting the original end of life of 2030 for the Beaver Plant and documentation supporting the revised end of life of 2040.
b. Please refer to the response to AWEC DR 158 Confidential Attachment B sheet "Assump" Cell D9. Please provide the basis for assuming an economic life of [redacted] after the in-service date. Please reconcile this assumption with the response to part (a), above.
c. Please refer to the initial filing in Docket No. UM 2152, page III-7, which indicates the expected life of the Beaver Plant as of 2019 was 2035. Please reconcile this expected life with the 2030 life represented in the response to AWEC DR 212. If PGE's response is that PGE revised its expected life after the production of the depreciation study, please provide all analysis supporting the reduction of the expected life of the Beaver Plant.
d. Please refer to PGE's Response to AWEC Data Request 158, part B. If the Program returns the turbines to like new condition, why has it only extended the expected life to 2040, when new turbines typically have expected lives of 40 or more years?
e. Please provide the expected life of combustion turbines assumed in PGE's 2023 IRP.

Response:

a. Clarifying the response to AWEC Data Request No. 212, the 2030 and 2040 dates referenced are planning targets that were created for the Beaver Enhanced Maintenance Plan. The objective of the 2013 Beaver Enhanced Maintenance Plan (EMP) Phase 1 was to extend safe and reliable operation of the Beaver steam plant, (HRSG Super-heaters), and 4 kV electrical system beyond year 2030. This was accomplished through a series of capital and maintenance projects to address existing and anticipated equipment conditions that could impact safety or reliable operation. The incremental CapEx and OpEx for the identified projects were significantly less than the cost of alternatives evaluated while preparing the 2014 Integrated Resource Plan (IRP). Phase 2 of the Beaver Enhanced Maintenance Plan addresses deferred maintenance on the combustion turbines, the Beaver Emissions Reduction Program, which will complete combustion upgrades to reduce NOX emissions, and other maintenance items. The objective of Phase 2 is to extend safe and reliable operation of the Beaver Plant beyond year 2030—targeting 2040 for planning purposes—and to reduce Beaver's environmental footprint.

b. The [redacted] referenced assumes an economic life out to 2035, which aligns with PGE's most recent depreciation study (Docket No. UM 2152).
c. The depreciation study is more current and its full depreciation date of 2035 is accurate. The referenced 2030 date was a planning target established in 2013.
d. These turbines are undergoing a major inspection along with component/parts refurbishment or replacement. This maintenance does not replace every component. For example, turbine rotors or turbine cases have a finite life but typically do not need replacement at each inspection interval. PGE is replacing some combined cycle equipment or supporting balance of plant equipment, based on condition assessment, but other equipment remains un-replaced. Nevertheless, regarding the 2040 date, PGE asserts again that this is an operational target date set by the Beaver Enhanced Maintenance Plan, rather than a planned economic end of life date.
e. The expected life of combustion turbines in PGE's 2023 IRP is 38 years.

June 8, 2023

To: Jesse Gorsuch
Alliance of Western Energy Consumers

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 416
PGE Response to AWEC Data Request 284
Dated May 25, 2023

Request:

Please refer to the response to AWEC DR 220, Attachment B. Please provide the share of these emissions that are attributed to retail customers in the 2023 IRP, as described in the IRP Appendix O. If PGE declines to provide such data, please provide the share of gas generation that is attributable to retail customers by year.

Response:

Attachment 284-A provides this data in the tab “Annual GHG Impacts of Actions” in column E.

June 8, 2023

To: Jesse Gorsuch
Alliance of Western Energy Consumers

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 416
PGE Response to AWEC Data Request 286
Dated May 25, 2023

Request:

Please refer to PGE's response to AWEC DR 245, parts a through d.

a. Please refer to PGE's response to part a of AWEC DR 245. Is it PGE's position that account 9030001 department 401: Business Customer Contact Ops should be unbundled to billing, consumer, or both?
b. Please refer to PGE's response to part a of AWEC DR 245. Does PGE agree that PGE has unbundled 100 percent of account 9030001 department 401: Business Customer Contact Ops to Consumer? If yes, please reconcile this with PGE's response to part a of this DR and part a of AWEC DR 245. If no, please provide citations to PGE's unbundling model to show that these costs are not unbundled to consumer.
c. Please refer to PGE's response to part a. Does PGE agree that the number of large customers, as used in the workpaper "2024 Customer Marginal Cost" sheet "Billing 2024", is a reasonable allocation factor for allocating account 9030001 department 401: Business Customer Contact Ops costs to customer classes? If no, why not? If yes, why does PGE not perform such allocations in the "Other 2024" sheet?
d. Please refer to PGE's response to part b of AWEC DR 245. Is it PGE's position that account 9030001 dept. 404: Customer Services Ops Admin should be unbundled to billing, consumer, or both?
e. Please refer to PGE's response to part b of AWEC DR 245. Does PGE agree that PGE has unbundled 100 percent of account 9030001 department 404: Customer Services Ops Admin to Consumer? If yes, please reconcile this with PGE's response to part d of this DR and part b of AWEC DR 245. If no, please provide pin citations to PGE's unbundling model to show that these costs are not unbundled to consumer.
f. Please refer to PGE's response to part b of AWEC DR 245. Does PGE agree that the number of customers, as used in the workpaper "2024 Customer Marginal Cost" sheet "Billing 2024", is a reasonable allocation factor for allocating account 9030001 department 401: Business Customer Contact Ops costs to customer

classes? If no, why not? If yes, why does PGE not perform such allocations in the "Other 2024" sheet?

g. Please refer to PGE's response to part c of AWEC DR 245. Is it PGE's position that account 9030001 dept. 432: Customer Contact Operations should be unbundled to billing, consumer, or both?
h. Please refer to PGE's response to part c of AWEC DR 245. Does PGE agree that PGE has unbundled 100 percent of account 9030001 department 432: Customer Contact Operations to Consumer? If yes, please reconcile this with PGE's response to part g of this DR and part c of AWEC DR 245. If no, please provide pin citations to PGE's unbundling model to show that these costs are not unbundled to consumer.
i. Please refer to PGE's response to part c of AWEC DR 245. Does PGE agree that the number of customers up to 200 kW, as used in the workpaper "2024 Customer Marginal Cost" sheet "Billing 2024", is a reasonable allocation factor for allocating account 9030001 department 432: Customer Contact Operations costs to customer classes? If no, why not? If yes, why does PGE not perform such allocations in the "Other 2024" sheet?
j. Please refer to PGE's response to part d of AWEC DR 245. Is it PGE's position that account 9030001 dept. 472: OPS Performance Solutions should be unbundled to billing, consumer, or both?
k. Please refer to PGE's response to part d of AWEC DR 245. Does PGE agree that PGE has unbundled 100 percent of account 9030001 department 472: OPS Performance Solutions? If yes, please reconcile this with PGE's response to part j of this DR and part d of AWEC DR 245. If no, please provide pin citations to PGE's unbundling model to show that these costs are not unbundled to consumer.
l. Please refer to PGE's response to part d of AWEC DR 245. Does PGE agree that the Billing Suballocation, as used in the workpaper "2024 Customer Marginal Cost" sheet "Billing 2024", is a reasonable allocation factor for allocating account 9030001 department 472: OPS Performance Solutions costs to customer classes? If no, why not? If yes, why does PGE not perform such allocations in the "Other 2024" sheet?

Response:

a., d., g., j. These costs should be assigned to the same category that they were assigned to in PGE's unbundled revenue requirement, which in these cases, was Other Consumer.
b., e., h., k. Yes, PGE did treat these items differently in unbundling and the customer marginal cost study and the treatment of these should be consistent between the unbundled revenue requirement and the customer marginal cost study,

c. Yes, PGE agrees that this is a reasonable allocation factor. This is not used as an allocator in the Other 2024 tab because there are no accounts that need to be allocated in this manner as they do not directly serve large business customers.

f. See PGE's response to Part c. of this data request.

i. Yes, PGE agrees that this is a reasonable allocation factor and does use it in the "Other 2024" sheet – see rows 11 and 15.

l. Yes, PGE agrees that this is a reasonable allocation factor for department 472 and it is not used in the "Other 2024" sheet as Other costs do not directly concern billing and as such this is not an appropriate allocator.

June 8, 2023

To: Jesse Gorsuch
Alliance of Western Energy Consumers

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 416
PGE Response to AWEC Data Request 287
Dated May 25, 2023

Request:

Please refer to PGE's response to AWEC DR 245, parts e and f. Please provide PGE's proposed or expected treatment of these costs within the "2024 Customer Marginal Cost" model.

Response:

PGE would expect to treat these costs as they are treated in PGE's unbundled revenue requirement, so they would be classified as other consumer in the customer marginal cost study.

June 8, 2023

To: Jesse Gorsuch
Alliance of Western Energy Consumers

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 416
PGE Response to AWEC Data Request 288
Dated May 25, 2023

Request:

Please refer to UE 416 Exhibit 1200, page 3.

a. Does PGE agree that wind resources have some capacity value? If no, why not?
b. Does PGE agree that solar resources have some capacity value? If no, why not?
c. Does PGE agree that not accounting for capacity value of wind in the cost of service study provides an inaccurate representation of the cost of energy? If no, why not?
d. In response to AWEC DR 250 PGE states “To temper the degree of impact this methodological shift has on customer prices, PGE maintains the treatment of a proxy wind resource as an energy-only resource.” Does PGE agree that the Customer Impact Offset provides an alternative method of tempering the impacts of modeling renewable generation costs? (The CIO is also discussed in UE 416 Exhibit 1300 page 9 .) If no, why not?

Response:

a. Yes, PGE agrees that wind resources provide some amount of capacity value.

b. Yes, PGE agrees that solar resources provide some amount of capacity value.

c. PGE acknowledges that a simplified marginal cost model, one in which capacity value is not stripped out of resources that primarily provide energy value and one in which energy and flexibility values are not stripped out of a resource that primarily provides capacity value, yields less precise marginal cost estimates compared to a more nuanced cost model.

d. In managing the price impacts of changes to PGE’s generation cost allocation approach, it is preferable to keep the adjustments within the marginal cost study such that relative allocations are not drastically changed. As stated in testimony (Exhibit 1200, pages 3-4), the current generation marginal cost study represents a shift from carbon emitting and renewable resources to exclusively modeling non-carbon emitting resources as the basis for allocating generation costs and recognizes the importance of incrementing this transition to mitigate prices among customer classes. PGE expects to make further adjustments to the Company's generation marginal cost study in future rate cases and will monitor impacts to customer subsets. Use of the Customer Impact Offset (CIO) would move beyond allocation of generation costs and enact more holistic allocation adjustments, which PGE finds unnecessary and potentially problematic if it masks other movement in cost allocation.

March 27, 2023

To: Marc Hellman
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 416
PGE Response to OPUC Data Request 263
Dated March 13, 2023

Request:

Please provide all research and planning workpapers for fleet electrification.

Response:

PGE objects to this request on the basis that it is unduly burdensome. Notwithstanding this objection, PGE responds as follows:

In September 2020, PGE announced plans to electrify more than 60% of our entire fleet by 2030, including electrifying 100% of our Class 1 vehicles (e.g., sedans, SUVs, small pickups, and forklifts) by 2025:[1]

- 100% electric Auto/Class 1 vehicles (by 2025)
- 70% electric light-duty Class 2 vehicles (e.g., pickups, large SUVs, vans)
- 40% electric medium-duty vehicles (e.g., flatbeds, service bodies, large vans, and bucket trucks)
- 30% electric heavy-duty vehicles (e.g., digger derricks, bucket trucks, and dump trucks)

Confidential Attachment 263-A provides PGE's response to OPUC Data Request No. 150 in Docket No. UE 394 (PGE's 2022 GRC). The studies and worksheets provided in this response have not since been updated, and at this point, there are no other additional research and/or planning as PGE is focused on replacing all non-EV fleet vehicles that are either an Auto or Class 1 by 2025.

Attachment 263-B provides PGE's current fleet electrification planning workpaper by vehicle class. This includes vehicles that have been ordered but not yet received, active vehicles, and vehicles that will be retired soon.

Attachment 263-A contains protected information and is subject to General Protective Order No. 23-309.

---

[1] PGE's September 2020 announcement is available here: https://portlandgeneral.com/news/2020-09-24-portland-general-electric-to-electrify-more-than-60-of-its-fleet

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UE 416

In the Matters of	)
	)
PORTLAND GENERAL ELECTRIC COMPANY,	)
	)
	)
Request for a General Rate Revision.	)
	)

EXHIBIT AWEC/303

GENERATION MARGINAL COST

(REDACTED)

Exhibit AWEC/303 contains Protected Information Subject to Modified General Protective Order No. 23-039 and has been redacted in its entirety.

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UE 416

In the Matters of	)
	)
PORTLAND GENERAL ELECTRIC COMPANY,	)
	)
Request for a General Rate Revision.	)
	)

EXHIBIT AWEC/304

FARADAY INCREMENTAL ENERGY

(REDACTED)

Exhibit AWEC/304 contains Protected Information Subject to Modified General Protective Order No. 23-039 and has been redacted in its entirety.

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UE 416

In the Matters of	)
	)
PORTLAND GENERAL ELECTRIC COMPANY,	)
	)
	)
Request for a General Rate Revision.	)
	)

EXHIBIT AWEC/305

FARADAY ECONOMIC ANALYSIS

(REDACTED)

Exhibit AWEC/305 contains Protected Information Subject to Modified General Protective Order No. 23-039 and has been redacted in its entirety.

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UE 416

In the Matters of	)
	)
PORTLAND GENERAL ELECTRIC COMPANY,	)
	)
	)
Request for a General Rate Revision.	)
	)

EXHIBIT AWEC/306

BEAVER ECONOMIC ANALYSIS

(REDACTED)

Exhibit AWEC/306 contains Protected Information Subject to Modified General Protective Order No. 23-039 and has been redacted in its entirety.

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UE 416

In the Matters of	)
	)
PORTLAND GENERAL ELECTRIC COMPANY,	)
	)
	)
Request for a General Rate Revision.	)
	)

EXHIBIT AWEC/307

UE 394 WORLD TRADE CENTER CONFIDENTIAL TESTIMONY

(REDACTED)

Exhibit AWEC/307 contains Protected Information Subject to Modified General Protective Order No. 23-039 and has been redacted in its entirety.