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June 6, 2018

***Via Electronic Filing and Federal Express***

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.
2018 Request for a General Rate Revision
**Docket No. UE 335**

Dear Filing Center:

Please find enclosed the Opening Rate Case Testimony and Exhibits of Bradley G. Mullins (AWEC/200-206) and Dr. Marc M. Hellman (AWEC/300-309) on behalf of the Alliance of Western Energy Consumers ("AWEC") in the above-referenced docket.

Pursuant to OAR 860-001-0170(2), and per the Commission's request, AWEC is also submitting an original and four (4) hard copies of its testimony and exhibits via Federal Express. The confidential portions of Mr. Mullins' and Dr. Hellman's testimony and exhibits are being handled in accordance with Order No. 18-047.

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

Sincerely,

*/s/ Haley M. Thomas*
Haley M. Thomas

Enclosures

## CERTIFICATE OF SERVICE

I HEREBY CERTIFY that I have this day served the **confidential portions of the Opening Rate Case Testimony and Exhibits of Bradley G. Mullins and Dr. Marc M. Hellman** upon the parties shown below by mailing copies via First Class U.S. Mail, postage prepaid, and by sharing copies via the Huddle workspace in this docket.

Dated at Portland, Oregon, this 6th day of June, 2018

Sincerely,

*/s/ Haley M. Thomas*
Haley M. Thomas


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**BEFORE THE**

**PUBLIC UTILITY COMMISSION OF OREGON**

**UE 335**

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| | ) |
| In the Matter of | ) |
| | ) |
| PORTLAND GENERAL ELECTRIC COMPANY, | ) |
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| | ) |
| Request for a General Rate Revision. | ) |
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# OPENING TESTIMONY OF BRADLEY G. MULLINS

**ON BEHALF OF THE ALLIANCE OF WESTERN ENERGY CONSUMERS**

**(REDACTED VERSION)**

**June 6, 2018**

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AWEC/205 – Responses to Data Requests

Confidential AWEC/206 – Confidential Attachments to Data Responses

# I. INTRODUCTION

**Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.**

A. My name is Bradley G. Mullins, and my business address is 1750 SW Harbor Way, Ste 450, Portland, Oregon 97201.

**Q. ARE YOU THE SAME WITNESS WHO FILED OPENING POWER COST TESTIMONY IN THIS DOCKET ON MAY 24, 2018?**

A. Yes.

**Q. WHAT IS THE PURPOSE OF YOUR OPENING TESTIMONY.**

A. I testify regarding my initial review of PGE's revenue requirement. In my review, I recommend a revenue requirement reduction of $28,440,143, relative to the rates that recently went into effect on January 1, 2018 in Docket No. UE 319 (the "2017 GRC"). My analysis is in contrast to the revenue increase of $85,908,262, or 4.8%, PGE reported in its initial filing. If one considers the tax savings from the reduction of the federal corporate income tax rate, however, it is apparent that the actual magnitude of the cost increases PGE proposes to pass onto ratepayers is much greater than 4.8%. Absent the beneficial impacts associated with that legislation, the magnitude of the increase is really 9.7% in a year with no new power plant additions. In addition to revenue requirement issues, I also testify regarding PGE's permanent direct access program, as well as a few other miscellaneous rate case issues.

**Q. WHAT WAS THE SCOPE OF YOUR REVIEW OF PGE'S REVENUE REQUIREMENT?**

A. I initially focused on tax expense, PGE's capital forecast, and other miscellaneous revenue requirement issues. Dr. Marc Hellman will also be providing testimony on behalf the Alliance of Western Energy Consumers ("AWEC") discussing primarily labor-related issues. My revenue requirement analysis incorporates the impact of Dr. Hellman's recommendations.

**Q. HAVE YOU PREPARED A SUMMARY OF AWEC'S ADJUSTMENTS?**

A. Yes. Table 1 below summarizes AWEC's initial revenue requirement adjustments. This does not account for the adjustments I propose to PGE's 2019 power cost forecast in AWEC/100.

**TABLE 1**
Contested Revenue Requirement Adjustments
Deficiency / (Sufficiency) ($000)

| | | | |
|---|---|---|---|
| **PGE Initial Filing, Deficiency** | | | **85,812** |
| **AWEC Adjustments:** | | | |
| A1 | Cost of Capital | (797) | |
| *Tax Cuts And Jobs Act* | | | |
| A2 | Composite Tax Rate Correction | (1,247) | |
| A3 | EDFIT Correction | (1,564) | |
| A4 | EDFIT Alternative Method | 111 | |
| A5 | Interim Period Deferral Amortization | (47,912) | |
| *Capital Expenditures* | | | |
| A6 | Rate Base Measurement Date | (11,584) | |
| A7 | Field Voice Communications / Spectrum | (3,715) | |
| A8 | Project Specific Adjustments | (179) | |
| A9 | Non-Discrete Capital Additions | (2,721) | |
| *Accumulated Deferred Taxes* | | | |
| A10 | PTC Carry Forwards | (7,182) | |
| A11 | Accrued Vacation | (500) | |
| A12 | Stock Incentive Plan | (362) | |
| A13 | Boardman Severance | (287) | |
| A14 | Injuries and Damages | (252) | |
| *Other Revenue Requirement Issues* | | | |
| A15 | Depreciation Reserve | (2,046) | |
| A16 | Trojan NDT Amortization | (725) | |
| A17 | Touchpoints R&D Tax Credit | (3,322) | |
| A18 | UE 283 Incentives Adjustment | (518) | |
| A19 | Dispatchable Generation Regulatory Asset | (1,221) | |
| A20 | Boardman Severance | (547) | |
| A21 | Level III Storm Escalation | (93) | |
| *Impact of adjustments Sponsored by Dr. Hellman* | | | |
| A22 | Employee Costs | (27,587) | |
| **Total Adjustments** | | | **(114,252)** |
| **Adjusted Revenue Requirement (Sufficiency)** | | | **(28,440)** |

Calculations underlying the revenue requirement adjustments in Table 1, including the rate base and operating income impacts, can be found in Exhibit AWEC/201. Brief summaries of the adjustments are as follows:

1. **Tax Cuts and Jobs Act.** I have identified several corrections associated with PGE's implementation of the Tax Cuts and Jobs Act in revenue requirement, including amortization of excess tax expenses reflected in revenue requirement deferred over the Interim Period of January 1, 2018 through December 31, 2018.

2. **Capital Expenditures.** I propose several changes to PGE's capital budget, including the adoption of an October 31, 2018 rate base measurement date and a project-level review of major projects.

3. **Accumulated Deferred Income Taxes.** I propose to remove several book-tax difference items from accumulated deferred income taxes reflected in rate base, including production tax credits.

4. **Other Revenue Requirement Issues.** I make a number of other corrections and adjustments to the revenue requirement calculation, including a provision for an R&D tax credit associated with the Customer Touchpoints system.

**Q. WHAT ARE YOUR RECOMMENDATIONS WITH RESPECT TO PGE'S PERMANENT DIRECT ACCESS PROGRAM?**

A. For PGE's permanent direct access program, I oppose PGE's proposal to extend the period for transition charges from five years to ten. I also recommend eliminating the current enrollment cap. Finally, I recommend establishing a credit for the freed-up value of capacity in the transition adjustment calculation in periods when PGE is capacity-short.

## II. TAX CUTS AND JOBS ACT

**Q. PLEASE PROVIDE SOME BACKGROUND ON THE TAX CUTS AND JOBS ACT.**

A. The Tax Cuts and Jobs Act ("TCJA"), HR 1 of the 115th Congress, was signed into law on December 22, 2017. Among other things, the TCJA resulted in a reduction to the Federal corporate income tax rate from 35% to 21%.

**Q. HOW DOES THE TCJA AFFECT THE CALCULATION OF REVENUE REQUIREMENT?**

A. The TCJA impacts revenue requirement in at least four ways. First, federal income tax expense included in the results of operations table must be stated at the lower, 21% rate. Second, balances associated with ADIT must be revalued at the new rate, including consideration of previously over-deferred amounts, often referred to as Excess Deferred Federal Income Taxes ("EDFIT"). Third, the tax expenses over-collected in rates over the period January 1, 2018 through December 31, 2018 (the "Interim Period") must be deferred and amortized to results. Fourth, the conversion factor used in the calculation of the revenue deficiency or surplus must be updated to reflect the TCJA.

**Q. HAS PGE CONSIDERED THESE IMPACTS?**

A. PGE's filing did not consider the revenue requirement impacts of the Interim Period tax. While PGE did consider the other elements necessary to implement the TCJA, I have identified a number of corrections and issues associated with those elements. I discuss those in the following sub-sections.

### a. <u>Impact on Federal Income Tax Expense</u>

**Q. HOW DOES THE LOWER TAX RATE IMPACT TAX EXPENSES INCLUDED IN REVENUE REQUIREMENT?**

A. Using the forecasting assumptions in PGE's initial filing, the impact on federal income tax expense of the new 21% tax rate is $75,569,264. This part of the TCJA represents one of the more straightforward impacts of the legislation on ratepayers. It may be calculated by comparing the income tax expense reflected in forecasted results, to the income tax expense calculated using the 35% tax rate that had been in effect prior to January 1, 2018. Importantly, income tax expense included in a utility's results of operations does not reflect the actual taxes the utility pays (i.e., current taxes). Instead, income tax expense includes a provision for current taxes, as well as deferred taxes. Thus, the impact of the lower tax rate may generally be calculated by comparing the current and deferred tax amounts calculated using the respective tax rates before and after the effective date, although one must also use the composite tax rate of the utility, taking into consideration the impacts of state and local income taxes.

**Q. WHAT COMPOSITE TAX RATE WAS INCLUDED IN PGE'S FILING?**

A. Considering state and local income taxes, PGE calculated a 27.5% composite income tax rate. PGE's state income taxes are apportioned between the three states of Oregon, Montana, and California. PGE also includes an amount apportioned to the City of Portland income taxes, which are also included in income tax expense. Multnomah County income taxes are not included in income tax expense because those are recovered through Schedule 106. In contrast, had a 35.0% tax rate been used, the composite income tax rate, using PGE's calculation, would have been 40.1%.

**Q. WHAT WAS THE REVENUE REQUIREMENT EFFECT OF THE TCJA TAX RATE?**

A. I've performed this calculation in Exhibit AWEC/202. After considering the excess deferred federal income taxes of $7,010,362, which will be discussed further below, PGE's filing really represents a rate increase to customers of $173,613,520, if the TCJA had not been implemented. Thus, from the perspective of evaluating the reasonableness of the Company's request for higher rates – the fifth in six years – the rate increase here is more appropriately viewed as a 9.7% rate increase. Given the passage of the TCJA, customers should be seeing rate reductions, not rate increases.

### b. Composite Income Tax Rate Corrections

**Q. DID YOU IDENTIFY ANY ISSUES WITH PGE'S COMPOSITE TAX RATE WHEN REVIEWING ITS INCOME TAX EXPENSE CALCULATIONS?**

A. Yes. In the course of my review, I identified a number of corrections to PGE's composite income tax rate calculations. I have calculated a lower composite income tax rate of 26.86%, in contrast to the 27.15% composite income tax rate PGE assumed in its filing. My calculation of the composite tax rate may be found on Page 2 of Exhibit AWEC/201.

**Q. WHERE CAN PGE'S CALCULATION OF ITS COMPOSITE INCOME TAX RATE BE FOUND?**

A. PGE's calculation of its composite income tax rate may be found in the workpaper titled "Blended Statutory Tax Rate 2019 GRC." That workpaper details the historical apportionment of taxable income between Oregon, Montana, and California, as well as to the City of Portland. It also considers the offsetting impacts of deducting state and local taxes when calculating federal income tax expense, as well as the impacts of deducting local taxes when calculating state tax expense.

**Q. WHAT CORRECTIONS HAVE YOU IDENTIFIED?**

A. The first issue I have identified is that PGE did not use the actual historical apportionment between the three states—Oregon, Montana, and California—where PGE has property, employees, or sales. Different states use different formulas for determining apportionment, so it is necessary to consider the historical apportionment when determining the composite rate. From what I can tell in the workpaper, PGE increased the historical apportionment factors, without any explanation, in order to force the calculation to tie to 27.15%.

Second, PGE did not consider the benefit of deducting Multnomah County income taxes on its state and federal tax returns. Schedule 106 only considers the taxes paid to

Multnomah County, and does not consider the tax savings associated with deducting those taxes when calculating state and federal income taxes.

Finally, PGE did not consider that the initial $1,000,000 of Oregon taxable income is taxed at a lower 6.5% tax rate, which shields approximately $10,000 in state tax expense.

**Q. WHAT IS THE IMPACT OF THESE CORRECTIONS?**

A. Applying the lower composite tax rate of 26.84%, as well as the graduated corporate income tax rate, produces a reduction of $783,640 of post-tax revenues, which corresponds to a $1,247,145 reduction to pre-tax revenue requirement.

**c. <u>Excess Tax Reserves</u>**

**Q. WHAT ARE EXCESS DEFERRED FEDERAL INCOME TAXES?**

A. The TCJA codifies several normalization provisions surrounding the treatment of EDFIT, which simplifies the treatment of the balance sheet impacts of the tax law change for public utilities. Similar provisions were put into place when the Tax Reform Act of 1986 was enacted.[1/]

Effectively, EDFIT represent a financial gain to the utility, and absent the TCJA normalization provisions surrounding EDFIT, a utility might have claimed that it was entitled to retain those benefits. Or, perhaps ratepayers might have claimed that they should receive those gains through a single lump-sum payment. The TCJA, however, simplifies the ratemaking treatment surrounding the tax changes by prescribing the specific methods that must be used by regulators to account for the EDFIT benefits associated with plant balances, avoiding some controversy over the way that those amounts get retuned to ratepayers.

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1/ <u>See, e.g.</u>, PLR 200743030.

Under Generally Accepted Accounting Principles ("GAAP"), the general rule is that when a change in the tax rate is enacted into law, the effects of the change must be reported in the period that includes the "enactment date."[2/] The normalization requirements for EDFIT in IRC § 168(i)(9), however, provide an exception to that general rule for public utilities.

For business enterprises other than a public utility, the change in tax rate results in material balance sheet impacts. For a non-utility business enterprise, deferred tax liabilities and assets must be revalued at the new tax rate. Most utilities have net deferred tax liability balances, which represent funds in the utility's possession being held in reserve to pay for taxes the utility must pay in the future. Thus, if the tax rate declines, the tax liability balance declines, resulting in the recognition of a gain, similar to the gain that occurs when the principal balance of a loan is forgiven. For non-utilities, this gain flows through the income statement in the current period, in one lump-sum.

For public utilities, however, the treatment is different. When implementing the normalization requirements of IRC § 168(i)(9)—a rare instance where the Internal Revenue Service may exercise authority over the specific ratemaking methodology that state regulatory commissions use to establish public service rates—the balance sheet gains associated with the change in tax rate must remain on the public utility's balance sheet and be considered in rate base as an excess tax reserve, i.e., EDFIT. Further, rather than recording those benefits in one lump-sum, as required under GAAP, this ratemaking requires the utility to recognize the financial gains associated with the lower tax rate over an extended period of time.

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[2/] See Financial Accounting Standards Board ("FASB"), Statement of Financial Accounting Standards No. ("SFAS") 109, Accounting for Income Taxes ¶ 27; See also FASB Accounting Standards Codification ("ASC") 740-25-47.

The amortization schedule is generally intended to correspond to the period over which the book-tax differences underlying EDFIT are expected to reverse, and two general methods are available to amortize the excess reserves to results—the Average Rate Assumption Methodology ("ARAM") and an Alternative Method.[3/] The ARAM methodology is computationally detailed and requires the utility to amortize the EDFIT reserve by plant vintage, ratably in proportion to the reversal of the book-tax differences underlying the EDFIT reserve. Provided the utility possesses the vintage data necessary to perform the ARAM method, the utility must use the ARAM when establishing rates. If the vintage data is not available, the utility must use the Alternative Method. Under the Alternative Method, EDFIT is reversed based on the weighted average life or composite rate used to compute depreciation for, or ratably over the remaining regulatory life of the property.

**Q. DO THE IRS NORMALIZATION REQUIREMENTS APPLY TO ALL DEFERRED TAX BALANCES?**

A. No. The IRS normalization requirements apply only to deferred tax balances associated with the use of accelerated depreciation—both the Modified Accelerated Cost Recovery System ("MACRS") and bonus depreciation—in IRC § 168k. Accordingly, normalization accounting methods outlined in the TCJA only apply to deferred tax balances associated with utility plant. Those deferred tax balances are often referred to as being *protected.*

With respect to the other deferred tax balances, those are often referred to as *unprotected*, since state Commissions, through the use of regulatory accounting, have greater leeway in determining how the gains on those EDFIT balances get returned to ratepayers.

[3/] The IRS has historically referred to the "Reverse South Georgia Method," although I used a generic term, Alternative Method, rather than referring to a specific geographic area of the United States.

**Q. DID PGE CONSIDER EDFIT IN ITS FILING?**

A. Yes. In its operating results PGE did include $7,010,362 in reversal in income tax expense. PGE's filing, however, does not identify the balances associated with the excess tax reserve accounts, or the amortization schedule.

**Q. DID PGE PROVIDE THE DATA NECESSARY TO SUPPORT ITS CALCULATION?**

A. No. While I conducted several rounds of discovery to determine the appropriate EDFIT, PGE has not yet provided sufficient information to review its calculation of EDFIT. PGE alleges that it has used the ARAM methodology. Notwithstanding, PGE could not provide any support for its calculation of the ARAM other than the values that were hard-coded into its PowerTax and Tax Provision modules. In response to AWEC Data Request 017, for example, PGE stated that it could not provide the calculations based on property vintage because those amounts were "imbedded in thousands of system calculations."[4/] I have reviewed this level of data for other utilities, and because having that data is a prerequisite of using the ARAM, it is impossible to consider the reasonableness of PGE's calculation without it.

**Q. PLEASE SUMMARIZE THE DISCOVERY YOU CONDUCTED.**

A. In AWEC Data Request 17, PGE was requested to provide calculations underlying its EDFIT calculations as of December 31, 2017. In that response, PGE claims to have used the ARAM and provided two attachments, which were two hard-coded outputs tables from the power tax model used to calculate PGE's tax provision. Attachment A contained all EDFIT balances, and Attachment B contained the reversal amount, but not the vintage level data necessary to support the ARAM calculation. Further, in Attachment B, PGE reported $8,115,311 of EDFIT reversal, in contrast to the $7,010,362 included in its filing.

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4/ Exhibit AWEC/205 at 8.

**Q. DID PGE CLARIFY WHY THE EDFIT REPORTED IN AWEC DATA REQUEST 17 WAS DIFFERENT THAN THE AMOUNT INCLUDED IN ITS FILING?**

A. Yes. In AWEC Data Request 45, PGE clarified that the $8,115,311 of EDFIT reversal reported in Data Request 17 was a more recent estimate. This update has been incorporated into Table 1 and Exhibit AWEC/201. The revenue requirement impact is a reduction to revenue requirement of $[redacted].

**Q. DOES PGE HAVE THE NECESSARY VINTAGE ACCOUNT DATA TO PERFORM THE ARAM?**

A. No. Based on the way PGE performs its depreciation study—using the equal life group approach—the accumulated book depreciation is not tracked by vintage. Rather, the accumulated depreciation amount by vintage is implied by the shape of the survivor curve, and allocated to the respective vintages. PGE confirmed in response to AWEC Data Request 46, subpart d that "Book depreciation is *allocated* to the vintage Tax Class records using a similar method to the plant depreciation module depreciation calculation."[5/]

**Q. HAVE YOU QUANTIFIED THE IMPACT OF USING THE COMPOSITE DEPRECIATION RATES?**

A. Yes. I had intended to perform this calculation by FERC account. When asked for the FERC-level data in AWEC Data Request 46, however, PGE was unable to produce the underlying data.[6/] Notwithstanding, PGE's composite depreciation rate is 3.53%, per UM 1809/ Stipulating Parties/102 Page 5.

For the protected EDFIT balance, I used the year-ending EDFIT balance related to property accounts reported in PGE's response to AWEC Data Request 10 of $754,070,950.[7/]

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5/ Exhibit AWEC/205 at 14 (PGE Resp. to AWEC DR 046) (emphasis added).
6/ Id.
7/ Id. at 4-7 (PGE Resp. to ICNU DR 010 Attach. A)

From that value, the EDFIT balance of $245,611,407 was calculated and, after applying the composite rate, an EDFIT amortization amount of $8,670,083. This calculation may be seen on Page 3 of AWEC/201.

To calculate the revenue requirement impact, I also assumed one year's worth of accumulated EDFIT amortization, resulting in an offsetting increase to rate base. PGE did not consider the declining EDFIT balance in its filing. After these adjustments I calculate an increase of $110,638 with respect to the EDFIT calculation.

**d. The Interim Period Deferral**

**Q. DID PGE CONSIDER THE INTERIM PERIOD TAX SAVINGS OVER THE PERIOD JANUARY 1, 2018 THROUGH DECEMBER 31, 2018 IN ITS RATE FILING?**

A No. PGE will recognize significant savings over the Interim Period, in connection with the TCJA. The Company filed a deferral application on December 29, 2017 to ensure this savings is captured for the benefit of customers.[8/] However, no determination has been made yet regarding when this savings will be returned. Because this savings can now be calculated with reasonable accuracy, I recommend that it begin to be passed back to customers at the start of the rate-effective period for this case.

**Q. HOW HAVE YOU CALCULATED THE DEFERRAL FOR INTERIM PERIOD TAX SAVINGS?**

A. In response to AWEC Data Request 126, PGE provided the final revenue requirement model used to establish rates in Docket UE 319. Using that model, I calculated the tax expense savings associated with the lower tax rate by changing the marginal tax rate in the model. My calculation may be found in Exhibit AWEC/203. In addition, it is also necessary to consider

8/ Docket No. UM 1920.

the EDFIT amortization that will accumulate in the Interim Period in an amount equal to that described above. The results of those calculations are as follows:

**TABLE 2**
Interim Period Tax Savings $

| | | |
|---|---|---|
| Tax Expense Savings (Pre-Tax) | | 70,791,000 |
| EDFIT Amortization (Post-Tax) | 8,670,083 | |
| Conversion Factor | 70.63% | |
| EDFIT Amortization (Pre-Tax) | | 12,275,256 |
| Total Interim Period Savings | | 83,066,256 |

**Q. HOW SHOULD THESE VALUES BE RETURNED TO RATEPAYERS?**

A. I recommend that the utility's typical general rate case cycle be a primary consideration when establishing the amortization period, with a target of returning the interim period savings over two rate case cycles. This treatment will promote rate stability and make it easier for PGE to forego its next rate case. Since PGE has been filing annual rate cases, I recommend using a two-year amortization period.

**Q. DO YOU RECOMMEND THAT THE INTERIM PERIOD DEFERRAL BE INCLUDED IN RATE BASE?**

A. No. I recommend that the amortization be tracked outside of rate base and included in an account that accrues interest at PGE's pre-tax cost of capital. Further, I recommend adopting a levelized amortization schedule that brings the balance to zero over the two-year period. This amortization treatment is similar to the treatment of Trojan decommissioning costs and the calculation may be found in Exhibit AWEC/201, Page 4. As detailed there, I calculate monthly, pre-tax amortization of $3,854,600, and annual amortization of $46,255,200.

**Q. WHAT IS THE REVENUE REQUIREMENT IMPACT OF YOUR RECOMMENDATION?**

A. The revenue requirement impact of the Interim Period deferral is a reduction of $47,911,701, the pre-tax amortization amount adjusted for revenue sensitive costs.

## III. CAPITAL EXPENDITURE FORECAST

**Q. PLEASE SUMMARIZE YOUR REVIEW OF PGE'S BUDGET.**

A. Another major driver of PGE's rate request is related to its budgeted capital expenditures. The problem with using these budgets, however, is that they are difficult, if not impossible, to independently verify. My review of PGE's budget consisted of four parts. First, I considered the date that PGE proposes to measure rate base. Second, I discuss an issue associated with the Field Voice Communications project, which was included in PGE's capital attestation in UE 319. Third, I performed a project-by project review of discrete projects with a capital budget exceeding $10,000,000. Fourth, I reviewed non-discrete capital projects, as well as smaller capital projects in comparison to historical capital spending levels.

**Q. HAS THE COMMISSION HISTORICALLY ALLOWED UTILITIES TO USE BUDGETED EXPENDITURES FOR RATEMAKING PURPOSES?**

A. In Oregon, there are no specific statutes or regulations specifying the appropriate test year to be used in a utility rate filing. In fact, the Company appears to have used some form of a future test year, relying in part on budgeted expenditures, for ratemaking purposes since at least 1974.[9/] Nevertheless, I am not aware that the Commission has ever expressly required the Company to use a future test year, or even endorsed the Company's decision to do so in every general rate case. Indeed, the Commission has previously recognized that it has allowed

[9/] See American Can Co. v. Lobdell, 55 Or.App 451, 462, 638 P.2d 1152, 1159 (1982) utilities to use future test years, historical test years, or a combination of the two,[10] and when it did affirmatively endorse the Company's use of a future test year, it did so recognizing that the Company "will undergo major expense changes which will not be felt until the second half of [the test year], and setting rates for the future cannot be accomplished in any equitable manner without considering the expenses."[11]

**Q. WHAT IS YOUR VIEW ON USING BUDGETED EXPENDITURES?**

A. My view is that using a historical test period is fairer to ratepayers. Notwithstanding, where the use of budgets is allowed, the Commission may appropriately exercise significant discretion when establishing those budgets.

**Q. WHAT AMOUNT OF FORECAST EXPENDITURES HAS PGE PROPOSED?**

A. The capital project data was provided in response AWEC Data Request 26, Confidential Attachment A, where PGE forecast capital expenditures of $673,320,026 in calendar year 2018.[12] PGE feeds its capital forecast into its system planner model, which calculates monthly plant balances into the future taking into consideration the effects of depreciation and retirements. Based upon my review, however, the capital project data was not entered into the system planning model correctly.

**Q. WHAT ERROR DID YOU IDENTIFY IN THE SYSTEM PLANNER MODEL?**

A. In OPUC Data Request 128, Attachment D, PGE detailed monthly plant additions entered into the System Planner model by function. While the total amount of annual capital was the same

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10/ In the Matter of the Revised Tariff Schedules Applicable to Electric Service. OPUC Docket UE 111, Order No. 00-091 (Feb. 14, 2000) (citing In the Matter of the Application of U S WEST Communications, Inc., for an Increase in Revenues, Order No. 97-171 (noting that the Commission used a combination of historical and future data for the test year)); see OAR 860-022-0019(1)(D), renumbered from OAR 860-013-0075.

11/ Re Portland Gen. Elec. Co., 8 P.U.R.4th 393, 399–400 (Dec. 23, 1974).

12/ PGE's total forecast capital expenditures were provided in unredacted form in its response to Staff DR 128 Attachment D.

between the two data sources, the timing of those additions was different. Table 3, below, details the difference between the monthly data between the two sources. Other input errors could be observed with respect to the functionalization of expenditures in the System Planner model as well.

**TABLE 3**
Monthly Plant Additions $
Variance System Planner vs. Project Data

| | System Planner | Project Data AWEC DR 26 | Variance |
|---|---|---|---|
| Jan 2018 | 17,435,114 | 19,269,778 | (1,834,664) |
| Feb 2018 | 30,568,463 | 32,421,604 | (1,853,141) |
| Mar 2018 | 27,495,093 | 28,879,281 | (1,384,188) |
| Apr 2018 | 233,150,081 | 210,375,887 | 22,774,194 |
| May 2018 | 24,843,873 | 27,007,373 | (2,163,499) |
| Jun 2018 | 48,212,868 | 54,414,283 | (6,201,415) |
| Jul 2018 | 27,124,832 | 34,343,828 | (7,218,996) |
| Aug 2018 | 22,173,359 | 29,029,823 | (6,856,465) |
| Sep 2018 | 42,140,318 | 40,342,048 | 1,798,270 |
| Oct 2018 | 26,376,047 | 33,890,645 | (7,514,598) |
| Nov 2018 | 27,953,937 | 35,142,648 | (7,188,710) |
| Dec 2018 | 145,846,041 | 128,202,829 | 17,643,212 |
| Annual | 673,320,026 | 673,320,026 | (0) |

**a. Rate Base Measurement Date**

**Q. WHAT RATE BASE MEASUREMENT DATE DOES PGE PROPOSE?**

A. PGE proposes using a rate base measurement period of December 31, 2019.

**Q. DO YOU AGREE WITH THIS MEASUREMENT DATE?**

A. No. In order to have adequate ability to review and confirm the used and usefulness of the capital, I recommend establishing a rate base measurement date of October 31, 2018. This date is appropriate because it will correspond to the update cycle in the annual update tariff, as well as the approximate timing of when PGE typically updates its load forecast.

**Q. WHAT DID THE COMMISSION SAY IN ITS ORDER IN DOCKET UE 319 ABOUT CAPITAL EXPENDITURES?**

A. Quoting its order in Avista's 2017 general rate case, the Commission stated that "parties wishing to include plant not-yet-in-service as part of the proposed revenue requirement in future rate cases … [must] be prepared to explain such proposals with particularity and to justify, via clear and convincing evidence, the circumstances providing the rationale for their inclusion in their general rate case application."[13/] My understanding of the Commission's directive in this order was to echo parties' frustrations with Oregon utilities' capital forecasting practices that can lead to the establishment of a capital budget that utilities can then fill with whatever capital projects they choose, regardless of whether those projects have been reviewed and found prudent. My recommendation to measure rate base as of October 1, 2018 helps address this concern.

**Q. WHAT IS THE IMPACT OF THIS ADJUSTMENT?**

A. I relied on PGE's response to Staff Data Request 128, Attachment D, to calculate the impact of this adjustment. I adjusted rate base by eliminating the incremental net plant in PGE's forecast beyond October 31, 2018. Further, I estimated the impact on depreciation expense, based on the incremental plant balances that were removed. Removing the projects forecast beyond October 31, 2018 results in a $173,799,978 reduction to gross plant, a $61,721,833 increase to depreciation reserves (calculated by taking 2/12ths of the 2018 depreciation and amortization expense). I did not have the data to quantify the impacts of this adjustment on EDFIT or depreciation expense, although those should be considered. The result of my analysis is a $11,583,802 reduction to revenue requirement.

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13/ Docket No. UE 319, Order 17-511 at 13 (Dec. 18, 2017).

**b. Field Voice Communications / Spectrum Projects**

**Q. DO YOU HAVE AN EXAMPLE TO ILLUSTRATE WHY A DECEMBER 31, 2018 RATE BASE MEASUREMENT DATE IS PROBLEMATIC?**

A. Yes. The Field Voice Communications project was identified in the 2018 GRC and was originally expected to be placed into service in December 2017. In addition, acquisition of spectrum was also considered in conjunction with this project. Based on my workpapers from UE 319, the total capital forecast in the 2017 GRC for this collection of projects was $[redacted][14], with $46,828,573 attributable to the Field Voice Communications project and $6,046,386 attributable to spectrum acquisition.

**Q. DID PGE FILE AN ATTESTATION THAT THE FIELD VOICE COMMUNICATIONS AND SPECTRUM PROJECTS HAD BEEN PLACED INTO SERVICE?**

A. Yes. PGE filed an attestation on December 29, 2017 in UE 319, stating that the Field Voice Communications and Spectrum projects had been placed into service and were being used for their intended purposes.

**Q. WHAT AMOUNT OF CAPITAL WAS PLACED INTO SERVICE FOR THESE PROJECTS?**

A. While some capital was transferred to plant with respect to Field Voice Communications and Spectrum projects in 2017, the amount actually transferred to plant represented only a small fraction (32%) of the capital that PGE had forecast in the 2017 GRC, and which was included in rates that went into effect on January 1, 2018. As can be noted in the attachment to PGE's response to AWEC Data Request 106, only $16,926,397 was transferred to plant with respect to these projects in 2018. For the Field Voice Communications project (P35938), the transfers to plant were $8,996,015, only about 19.2% of the amount forecast in the rate case. The

[14] AWEC confirmed with PGE that it could use this figure in Mr. Mullins' UE 335 testimony.

Spectrum project was placed into service with total capital of $5,938,311 for the 700mhz phase (P36005) and $1,992,070 for the 200mhz phase (P36354). Thus, while I have no reason to doubt that PGE placed a portion of these projects into service, as attested, PGE's total capital budget for these projects, and the amount included in rates on January 1, 2018, was overstated by $35,948,562. Parties had no meaningful opportunity to contest or review those amounts.

**Q. DID PGE ALSO INCLUDE THE FIELD VOICE COMMUNICATIONS PROJECTS IN THIS CASE?**

A. Yes. The Field Voice Communications project represents a major portion of PGE's capital forecast in this case, even though the project was already included in rates in the 2017 GRC. In this case, PGE proposes to include $33,449,021 in its budget for the Field Voice Communications project. This is the approximate amount that had been included in rates on January 1, 2018 but never actually placed into service.

**Q. WHAT DO YOU RECOMMEND WITH RESPECT TO THE FIELD VOICE COMMUNICATIONS AND SPECTRUM PROJECTS?**

A. The circumstances surrounding the Field Voice Communications project further supports the use of a rate base measurement period that allows for some review by the parties, as I have recommended above.

Since PGE provided the attestation, however, I further recommend a disallowance in the current case equal to the revenue requirement PGE will collect over the period January 1, 2018 through December 31, 2018, for the property that was included in rates but never actually placed into service. Using the $35,948,562 rate base amount described above, the impact of this recommendation is a $3,715,452 reduction to revenue requirement.

### c. Project Specific Adjustments

**Q. PLEASE SUMMARIZE YOUR REVIEW OF MAJOR PROJECTS.**

A. I performed a project-specific review for major, discrete projects. My project-specific review did not extend to non-discrete projects, such as blanket capital authorizations. Since the blanket projects do not represent any particular project, it is not possible to review those on a project-by-project basis. Accordingly, I reviewed each discrete project with a total capital budget exceeding $10,000,000. For smaller projects, I considered those as non-discrete, since due to the large volume of projects, it is not possible or practicable to perform a project-by-project review of those items. The projects I reviewed are:

- P35619 CET Install Oracle CC&B/MDM Systems
- P35679 Construct Marquam Project
- P35938 Field Voice Communications System
- P35329 Blue Lake/Gresham - System Upgrades
- P35980 PCB Transformer Replacement
- P36394 Vintage Vehicle Replacement II
- P22449 Colstrip Capital Project

**Q. DO YOU CONTEST THE PRUDENCE OF ANY FORECAST INVESTMENT?**

A. While I do not contest the prudence of any project, I have identified a number of inconsistencies between the capital forecast and the underlying documentation. In addition, I also consider the vehicle replacement program as a discrete project, and propose to use a budget that is more in line with historical expenditures associated with vehicle replacement.

**Q. WHAT DID YOU DISCOVER WITH RESPECT TO YOUR REVIEW OF PROJECT CET INSTALL ORACLE CC&B/MDM SYSTEMS (CUSTOMER TOUCHPOINTS)?**

A. Project P35619 represents the Customer Touchpoints projects and was extraordinarily expensive. In AWEC Data Request 107, I conducted discovery with respect to this project. Based on that discovery, it appears that the Customer Touchpoints project has been severely over budget. PGE indicates that it currently expects the project to cost $153,942,650, which is significantly higher than the initial estimates for this project of $[redacted], noted in the project justification forms. Further, that amount is much higher than the $[redacted] identified in the project data provided in response to AWEC Data Requests 26.

**Q. HOW MUCH CAPITAL HAS BEEN SPENT WITH RESPECT TO THE CUSTOMER TOUCHPOINTS PROJECT?**

A. According to Attachment B to PGE's response to AWEC Data Request 107, $129,001,910 had been spent through April of 2018.

**Q. HAS THE CUSTOMER TOUCHPOINTS PROJECT BEEN PLACED INTO SERVICE?**

A. Yes. Both applications underlying the Customer Touchpoints projects went live on May 14, 2018.

**Q. DO YOU CONTEST THE AMOUNT OF CAPITAL PGE HAS INCLUDED FOR THE CUSTOMER TOUCHPOINTS PROJECT?**

A. No. However, I recommend that PGE be limited to recovery plant additions identified in PGE's initial filing, even though it currently estimates that it will likely further exceed its budget on the Customer Touchpoints project. Based on PGE's Response to AWEC Data Request 116, there are legitimate questions about some activities late in the development process leading to these budget overages. Because PGE has not specifically requested the budget overages in this case, I have not reviewed those amounts for the purpose of preparing this testimony.

**Q. WHAT HAVE YOU DISCOVERED WITH RESPECT TO YOUR REVIEW OF THE MARQUAM PROJECT?**

A. The Marquam Project represents a series of infrastructure improvements around the south waterfront. I conducted discovery with respect to this project in AWEC Data Request 108, where PGE describes the project as "a new 115kV state-of-the-art substation and two feeders."

**Q. WHEN IS THE MARQUAM PROJECT EXPECTED TO BE PLACED INTO SERVICE?**

A. The majority of the capital for this project was expected to be placed into service in April of 2018. Based on the attachment provided with AWEC Data Request 108, the majority of the capital was actually transferred to plant in April. This leads me to believe that the project is on schedule and within budget. Thus, I do not oppose using PGE's budget for the Marquam project in rate base.

**Q. PLEASE SUMMARIZE YOUR REVIEW OF THE FIELD VOICE COMMUNICATIONS PROJECT.**

A. I conducted discovery with respect to the Field Voice Communications project in AWEC Data Request 131. Based on the adjustment related to this project discussed above, I am not proposing any additional adjustments based upon my review of that discovery.

**Q. PLEASE SUMMARIZE YOUR REVIEW OF THE BLUE LAKE/GRESHAM - SYSTEM UPGRADES PROJECT.**

A. The majority of this project was expected to be placed into service in December 2018, and for that reason, was not considered in my analysis based upon the rate base measurement date identified above. Notwithstanding, an initial phase of this project was budgeted to go into service in the spring of 2018, and I have not identified any reason to contest those amounts.

**Q. PLEASE SUMMARIZE YOUR REVIEW OF THE VINTAGE VEHICLE REPLACEMENT PROGRAM.**

A. In reviewing PGE's vintage vehicle replacement program, I reviewed actual spending on vehicles over the three-year period 2015 through 2017 to evaluate the reasonableness of PGE's capital budget. I have observed that the capital budgets for this capital category have varied materially year to year, and have actually declined in recent years. Table 4 details the historical rate of spending for this project based on the data provided in response to AWEC Data Request 106.

**TABLE 4**
Historical Spending on Vintage Vehicle Replacement $

| 2015 | 2016 | 2017 | Avg | 2018 Forecast | Adj. |
|---|---|---|---|---|---|
| 12,257,743 | 8,332,634 | 7,678,839 | 9,423,072 | [redacted] | (2,080,674) |

Based on this historical pattern, my recommendation is to use the three-year average for budgetary purposes. After prorating for the shortened 10-month forecast period, the impact of this recommendation is a $179,206 reduction to revenue requirement.

**Q. PLEASE SUMMARIZE YOUR REVIEW OF THE PCB TRANSFORMER REPLACEMENT PROJECT.**

A. I conducted discovery with respect to the PCB Transformer Replacement project in AWEC Data Request 129. As noted in that response, PGE has only replaced 2,683 out of 6,400 transformers identified with respect to the project. Based on PGE's response, I do not contest the budget for this project, at this time, since there are still a large number of transformers that need to be replaced.

**Q. PLEASE SUMMARIZE YOUR REVIEW OF THE COLSTRIP CAPITAL PROJECT.**

A. PGE forecasts $[redacted] of capital with respect to the Colstrip Capital project in AWEC Data Request 133. This amount represents ongoing capital maintenance of the facility which is managed by Talen Energy. Given the approximate 296 MW of capacity PGE receives from Colstrip, the magnitude of that ongoing capital investment is significant. At the current rate of ongoing capital maintenance at the Colstrip plant, ratepayers might be stuck with hundreds of millions of dollars in incremental stranded costs at the end of Colstrip's waning useful life. Accordingly, I viewed it to be relatively important to have a clear understanding of the economics of these ongoing capital investments from the perspective of ratepayers.

**Q. DID PGE PERFORM ANY ECONOMIC ANALYSIS WITH RESPECT TO THE ONGOING CAPITAL MAINTENANCE AT COLSTRIP?**

A. No. In its response AWEC Data Request 133, PGE stated "PGE's operating agreement with Talen allows for Talen to determine annually what capital work is required to operate the plant safely and reliably within its environmental permitting requirements through its planned operating lifetime."

**Q. WHAT DO YOU RECOMMEND WITH RESPECT TO THE COLSTRIP CAPITAL PROJECTS?**

A. While I do not oppose PGE's capital budget for Colstrip at this time, I am concerned that PGE is doing very little to consider the economics of these ongoing capital maintenance investments. In its rebuttal testimony, PGE should perform such a review to demonstrate that the $[redacted] rate of investment at Colstrip represents an efficient use of ratepayer money.

**d. Non-discrete Capital Additions**

**Q. PLEASE SUMMARIZE YOUR ANALYSIS OF NON-DISCRETE CAPITAL ADDITIONS.**

A. For those projects which could not be independently verified, I looked to historical spending levels by function to determine a reasonable amount of spending by function in the forecast period. When making this determination, in relation to historical levels, the discrete major projects were removed from the historical data.

**Q. WHAT WAS THE RESULT OF YOUR ANALYSIS?**

A. Table 4, below, summarizes the results of my analysis for non-discrete capital additions.

**TABLE 4**
Non-Discrete Capital Forecast Analysis
Proposed Annual Expenditure Rate By Function $
Source: AWEC Data Request 106

| Function | 2015 | 2016 | 2017 | Average | 2018 Forecast | Adjustment |
|---|---|---|---|---|---|---|
| Distribution | 127,244,120 | 149,704,998 | 203,513,001 | 160,154,040 | 224,788,384 | (21,275,383) |
| General | 54,210,927 | 53,421,194 | 75,283,987 | 60,972,036 | 48,542,373 | 26,741,614 |
| Other Prod. | 22,504,082 | 37,359,459 | 34,069,444 | 31,310,995 | 23,790,548 | 10,278,897 |
| Intangible | 16,425,506 | 15,633,374 | 21,770,986 | 17,943,289 | 39,423,839 | (17,652,853) |
| Hydro | 11,795,877 | 20,436,592 | 8,417,303 | 13,549,924 | 27,886,892 | (19,469,589) |
| Transmission | 4,704,304 | 5,530,025 | 12,193,220 | 7,475,850 | 36,610,746 | (24,417,526) |
| Steam Prod. | 1,824,630 | 744,379 | 404,507 | 991,172 | 378,233 | 26,274 |
| *Total* | 238,709,446 | 282,830,021 | 355,652,449 | 292,397,305 | 401,421,016 | (45,768,567) |

As can be seen, PGE's forecast for non-discrete capital increases dramatically in 2018 relative to historical levels. The rate of capital expenditures on non-discrete capital has been accelerating, and between 2015 and 2018 (just a few short years), PGE's forecast would result in nearly doubling the rate of capital expenditures for non-discrete capital projects.

**Q. WHAT DO YOU RECOMMEND?**

A. I recommend using the 2017 rate of expenditures to establish the budgeted level of rate base in this matter. Under this approach, PGE would slow its rate of capital spending to be consistent with the rate experienced in 2017, which is still higher than the 2015-2017 average. While I believe there is merit in using the three-year average to determine the capital expenditure rate, use of the 2017 rate is as an approach is reasonable given the overall circumstances in this case. This adjustment is further prorated to reflect only ten months of non-discrete capital additions, since the non-discrete capital additions beyond October 31, 2018 were removed in my adjustment related to the rate base measurement date above.

**Q WHAT IS THE IMPACT OF YOUR ADJUSTMENT?**

A. After prorating, the impact is a reduction of $38,140,472 in capital additions forecast over the period January 1, 2018 through October 31, 2018.

**Q. DOES THIS ADJUSTMENT OVERLAP WITH DR. HELMAN'S ADJUSTMENT WITH RESPECT TO LABOR?**

A. I assume that the capital portion of Dr. Hellman's adjustment is offsetting to this capital adjustment, and thus offsets this rate base reduction by $11,814,081. It is also necessary to exclude incremental depreciation, depreciation reserves, and deferred taxes. I expect those impacts to be relatively small, and have not considered those for this round of testimony. After adjusting for Dr. Hellman's recommendations, the result is a $26,326,392 reduction to rate base and a corresponding $2,720,956 reduction to revenue requirement.

## IV. ACCUMULATED DEFERRED INCOME TAXES

**Q. WHAT ARE ACCUMULATED DEFERRED INCOME TAXES?**

A. Deferred tax assets and liabilities are, where appropriate, reflected in rate base valuation as Accumulated Deferred Income Taxes ("ADIT"). In revenue requirement, ADIT is considered a source—or use—of "no-cost capital." If a utility recognizes a deduction for tax accounting purposes earlier than the expense would otherwise be recognized for ratemaking purpose, the utility is allowed to retain the cash benefits of the early deduction, treating it as a source of financing. Depreciation expense is the most common example. For tax purposes, a utility is often provided with the ability to depreciate property using *liberalized*, accelerated depreciation methodologies. For regulatory purposes, however, depreciation expense is calculated based largely on straight-line methodologies—albeit calculated in complex depreciations studies—which typically assume longer lives. Thus, a utility may claim tax benefits associated with the cost of utility property that is, in most instances, earlier than reflected in the tax expenses uses for ratemaking. A well-known example of this timing difference is bonus depreciation, which a utility may claim for tax purposes, but must depreciate the eligible facility for regulatory purposes on a straight-line basis. To account for this timing difference, the cash benefit received by the utility as a result of the different depreciable lives is treated as a source of no-cost capital, and deducted from rate base through ADIT.

**Q. PLEASE PROVIDE AN OVERVIEW OF YOUR ADJUSTMENTS RELATED TO ADIT.**

A. The Exhibit PGE/200 workpaper titled "2019 Deferred Tax Detail" details all of the deferred tax amounts PGE proposes to include in revenue requirement in this matter, although in response to AWEC Data Request 10, Attachment A, PGE updated the information in that workpaper.[15/] I contest several ADIT items.

[15/] Exhibit AWEC/205 at 4-7 (PGE Resp. to ICNU DR 010).

### a. Production Tax Credit Carryforwards

**Q. WHAT ARE PRODUCTION TAX CREDITS CARRYFORWARDS?**

A. Internal Revenue Code ("IRC") § 45, establishes the availability of production tax credits for generation from certain renewable sources of power supply.[16] Production tax credits are considered to be a general business credit, the utilization of which are governed by IRC § 38. Under that section, a general business credit may not reduce a business's tax liability below 25% of its regular tax liability.[17] In addition, a general business credit may not reduce a business's tentative minimum tax below its tentative minimum tax, the tax computed for purposes of the alternative minimum tax.[18] To the extent that a credit is not utilized in any particular tax year, however, it may be carried forward to offset tax liability in future tax years for a period of twenty years.[19]

**Q. WHAT AMOUNT OF PRODUCTION TAX CREDIT CARRYFORWARDS DOES THE COMPANY PROPOSE IN RATE BASE IN THIS MATTER?**

A. According to the workpaper titled "2018 Deferred Tax Detail.xlsx" provided along with Exhibit No. PGE/200, the Company proposes to include $69,489,835 in ADIT for production tax credit carryforwards. In UE 319, PGE forecast a production tax credit carryforward balance of $60,019,000. That is in contrast to the balance of $49,582,793 included in PGE's tax provision for December 31, 2017.

16/ IRC § 45
17/ IRC § 38
18/ Id.
19/ Id.

**Q. WHY DO YOU PROPOSE TO REMOVE PRODUCTION TAX CREDITS FROM ADIT IN THIS MATTER?**

A. I discuss three general reasons why it is not appropriate to include production tax credit carryforwards in ADIT in this matter. First, as detailed above, PGE has historically overstated the production tax credit carry forward balances in prior rate cases, relative to the amounts that have actually been included on its tax provision. Second, these carryforwards represent significant balances that were not considered in the request for proposal processes where the underlying renewable resources were selected. Third, a production tax credit carryforward is created by the Company's inability to generate sufficient taxable income in any given tax year, not a timing difference in the recognition of costs and revenues between tax and regulatory accounting methodologies.

**Q. WHAT COMPANY RESOURCES GENERATE PRODUCTION TAX CREDITS?**

A. Production tax credits are primarily produced by the Biglow and Tucannon River wind facilities, although the Company generates a small amount of production tax credits from the Oak Grove solar project. In addition, the production tax credits generated from Phase 1 of the Biglow wind facility begin to phase out later this year, followed by the phasing out of credits for Biglow Phases 2 and 3 in 2019 and 2020, respectively. As that happens, these large deferred tax asset balances will decline. Although if PGE proceeds with building a new renewable resource, we will likely see the carryforward balances growing to even higher levels.

**Q. WERE THESE RESOURCES SELECTED BASED ON PGE'S REPRESENTATION THAT THE PRODUCTION TAX CREDITS WOULD BE FULLY UTILIZED?**

A. Yes. For instance, in justifying the prudence for Tucannon, PGE noted that the top three factors it analyzed in the request for proposals that ultimately led to the selection of Tucannon were "capacity, transmission costs and risks, and the ability to use production tax credits."[20/] To my knowledge, PGE did not consider that it would be unable to utilize the credits generated from these facilities, when considering whether to make the investments.

**Q. ARE THE TAX CREDIT CARRYFORWARDS TIED TO TIMING DIFFERENCES BETWEEN TAX AND REGULATORY ACCOUNTING?**

A. No. A production tax credit carryforward is not created as a result of any difference between tax and regulatory accounting. It is driven by the ability of the Company to generate sufficient taxable income in a particular tax year to utilize the credits. If the Company's revenues were lower than expected due to unfavorable market conditions, for example, such a scenario could reduce the taxable income of the Company, resulting in the creation of production tax credit carryforwards. Plus, production tax credits are not covered under the IRS normalization rules, and for that reason there is no statutory requirement to include those balances in rate base.

**Q. DOES THE COMPANY HAVE AN INCENTIVE TO UTILIZE PRODUCTION TAX CREDIT CARRYFORWARDS ON ITS TAX RETURN?**

A. No. If production tax credit carryforwards continue to be reflected in rate base, the Company has little incentive to utilize those assets because it earns a return on these tax assets.

**Q. WHAT IS THE REVENUE REQUIREMENT IMPACT OF REMOVING PRODUCTION TAX CREDIT CARRYFORWARDS FROM ADIT?**

A. Removing production tax credit carryforwards from ADIT results in a revenue requirement reduction of $7,182,100 reduction to revenue requirement.

**Q. DO YOU HAVE AN ALTERNATIVE RECOMMENDATION?**

A. Yes. If the Commission disagrees with my recommendation above, then at a minimum, it should reduce PGE's assumed carryforward balance to recognize the Company's tendency to

[20/] Docket No. UE 283, PGE/400 at 7:17-19.

over-forecast that amount in rates. I recommend that PGE's production tax credit carryforward balance be assumed to equal the $49,582,793 it included in its tax provision for December 31, 2017. Reducing PGE's assumed carryforward balance will also recognize the anticipated reduction to this balance in the near term as production tax credits from Biglow 1 begin rolling off.

### b. Accrued Vacation

**Q. WHAT AMOUNT OF ADIT HAS PGE INCLUDED IN REVENUE REQUIREMENT RELATED TO ACCRUED VACATION?**

A. PGE included ADIT associated with accrued vacation in the amount of $4,842,278.

**Q. IS THE ADIT ASSOCIATED WITH ACCRUED VACATION APPROPRIATELY INCLUDED IN RATE BASE?**

A. No. ADIT related to accrued vacation arises due to a timing difference of when those costs are incurred for GAAP purposes and when they are deductible for tax purposes. For GAAP purposes, an amount is deduced against operating revenues when an employee earns the vacation days. For tax purposes, those amounts are only deducted when paid, i.e., when the employee actually uses the accrued vacation days. Since ratepayers do not receive a financing benefit as a result of this timing difference through a reduction in rate base, it is not appropriate for ratepayers to incur the deferred tax consequences resulting from such timing difference.

**Q. WHAT IS THE IMPACT OF THIS ADJUSTMENT RELATED TO ACCRUED VACATION?**

A. Removing the $4,842,278 ADIT amount from rate base results in a reduction of $500,472 reduction to revenue requirement.

### c. Management Stock Incentive Plan

**Q. WHAT AMOUNT OF ADIT HAS PGE PROPOSED TO INCLUDE RELATED TO ITS MANAGEMENT STOCK INCENTIVE PLAN?**

A. PGE has proposed to include ADIT of $3,502,315 related to its management stock incentive plan.

**Q. WHAT DO THESE ADIT AMOUNTS REPRESENT?**

A. PGE provided an overview of these amounts in response to AWEC Data Request 100.[21/] According to PGE these amounts "represent[] the timing difference of when the costs of stock incentive plans are recorded for book versus tax. For book purposes these costs are expensed, straight line, over the vesting period. For tax purposes, the costs are deducted on the vesting date. The difference in timing between when the expense is recognized for book and tax purposes, creates a temporary difference that results in a deferred tax asset or liability."

**Q. ARE THESE AMOUNTS APPROPRIATELY CONSIDERED FOR RATEMAKING?**

A. No. Management stock incentive plans are typically not considered for ratemaking, since they are often directly tied to earnings, which benefit shareholders.

**Q. WHAT IS THE IMPACT OF REMOVING THOSE AMOUNTS?**

A. Removing the ADIT associated with the management stock incentive plan results in a $361,981 reduction to revenue requirement.

### d. Boardman Severance

**Q. WHAT AMOUNT OF ADIT HAS PGE INCLUDED RELATED TO BOARDMAN SEVERANCE PAYMENTS?**

A. PGE includes $2,774,733 of ADIT associated with Boardman Severance payments.

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21/ Exhibit AWEC/205 at 16 (PGE Resp. to AWEC DR 100).

**Q. WHAT DOES THIS AMOUNT REPRESENT?**

A. This amount is tied to the tax timing of the Boardman severance payments, which are currently being collected through Schedule 145. In response to AWEC Data Request 99, PGE confirmed that the forecasted severance payments related to the cessation of coal-fired operations at Boardman are being collected through PGE Schedule 145 and are not included in the UE 335 revenue requirement.

**Q. IS THIS AMOUNT APPROPRIATELY CONSIDERED IN REVENUE REQUIREMENT?**

A. No. Since the severance payments are not being considered in revenue requirement, the amounts should also be excluded from ADIT. In addition, the way that the severance expense is being booked in PGE's financial statements, which gives rise to the ADIT, has no bearing on the way PGE considers those costs in rates.

**Q. WHAT IS THE IMPACT OF THIS ADJUSTMENT?**

A. Removing the Boardman Severance ADIT amount results in a $286,782 reduction to revenue requirement.

**e. <u>Provision for Injury and Damages</u>**

**Q. WHAT AMOUNT OF ADIT HAS PGE CONSIDERED WITH RESPECT TO ITS PROVISION FOR INJURIES AND DAMAGES?**

A. PGE's rate base includes an ADIT item in the amount of $2,438,685 related to its provision for injuries and damages. For tax purposes, the injury and damages amounts are recorded when it becomes probable that actual liability will result. For tax purposes the injuries and damages amounts are deductible when paid.

**Q. IS ADIT RELATED TO INJURIES AND DAMAGES APPROPRIATELY CONSIDERED IN REVENUE REQUIREMENT?**

A. No. In the case of injuries and damages, the regulatory treatment follows the tax treatment, in that the cost is recognized based on the timing of when PGE actually makes the liability payment and does not correspond to the timing used for book purposes.

**Q. WHAT IS THE IMPACT OF REMOVING THIS ADIT ITEM?**

A. Eliminating this ADIT item results in a $252,050 reduction to revenue requirement.

## V. MISCELLANEOUS REVENUE REQUIREMENT ISSUES

### a. Depreciation Reserves

**Q. WHAT HAVE YOU DISCOVERED WITH RESPECT TO DEPRECIATION RESERVES?**

A. In response to AWEC Data Request No. 002, PGE confirmed that its depreciation reserves were understated by $19,800,000 due to a calculation error. Applying this correction reduces revenue requirement by $2,046,423.

### b. Trojan Decommissioning Trust

**Q. WHAT AMOUNT OF AMORTIZATION DOES PGE REPORT FOR THE TROJAN NUCLEAR DECOMMISSIONING TRUST BALANCES.**

A. In PGE's initial filing it assumed $2,500,000 of amortization associated with Trojan Nuclear Decommissioning Trust ("NDT") balances.

**Q. HOW DID PGE CALCULATE THAT AMOUNT OF NDT AMORTIZATION?**

A. In response to AWEC Data Request 120, PGE described the methodology that it used to calculate that level of amortization. PGE states that balances, expected rate of return on trust assets, cost estimates, and other parameters were established in a model designed to bring the balance of the trust down to zero by 2034.

**Q. DOES THE $2,500,000 OF AMORTIZATION BRING THE BALANCE DOWN TO ZERO BY 2034?**

A. Based on the level of amortization PGE proposes, the balance will decline to well below zero by 2034. In its response to AWEC Data Request 120, PGE confirmed this fact, and noted that the actual amount of amortization necessary to bring the balance down to zero is $1,800,000.[22/]

**Q. WHY DOES PGE PROPOSE A HIGHER AMOUNT OF AMORTIZATION?**

A. PGE's justification for the higher amount of amortization is that it is "currently in the process of renewing our Nuclear Regulatory Commission license at Trojan for an additional 40 years, which will add considerable uncertainty associated with the spent nuclear fuel at the Trojan site"[23/]

**Q. DO YOU AGREE WITH PGE'S PROPOSAL?**

A. No. If the life is extended for an additional 40 years, that would spread the decommissioning cost over a longer period, which would justify a lower level of amortization. In addition, the current balances will be subject to interest over a longer period, reducing the ratepayer expense associated with the decommissioning expense.

**Q. WHAT IS YOUR RECOMMENDATION?**

A. I recommend that the Trojan NDT amortization of $1,800,000 be used in establishing revenue requirement, resulting in a $725,069 reduction to revenue requirement.

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22/ Exhibit AWEC/205 at 29 (PGE Resp. to AWEC DR 120)
23 Id.

c. **Customer Touchpoints R&D Tax Credit**

**Q. WHAT ISSUE HAVE YOU IDENTIFIED WITH RESPECT TO PGES ABILITY TO CLAIM AN R&D TAX CREDIT FOR THE TOUCHPOINTS SYSTEM.**

A. Under IRC § 41(d)(4)(E), internal use software of a utility may generally not be claimed toward an R&D tax credit. The cost of developing software for an accounting system, for example, has traditionally not been considered a qualified research expenditure and thus eligible towards the credit.

On October 4, 2016, however, the IRS published new regulations that clarify and provide exceptions to the general rules surrounding internal use software. Under the new regulations, software developed to enable a taxpayer to interact with third parties or allow third parties to initiate functions or review data on the taxpayer's system are eligible and may be claimed as a qualified research expenditure.

For utilities, this means that a fairly broad range of utility applications, which were formerly considered to be internal use software, may now be eligible qualified research expenditures. Costs associated with building EIM-related applications, which interface with the California Independent System Operator, for example, would likely be eligible under this regulation. Further, applications such as the Touchpoints projects, which allow third-party ratepayers to review billing data on the utility's system, and provide functions that allow the utility to interact with ratepayer load will also partially qualify for the credit. In Exhibit AWEC/204, I have attached the Federal Register notice which provides an outline the new internal use software regulation.

For applications that contain elements that are considered internal use software and other elements which are outwardly facing, only the portion of the software which are outwardly facing may be claimed toward the credit. The regulations, however, provide a safe harbor applicable to dual use software, where 25% of the expenditures may be considered toward the credit, provided that at least 10% of the project was related to outward facing functionality.

**Q. DID PGE INCLUDE ANY R&D TAX CREDITS IN ITS FILING?**

A. No. Based on my understanding of the complexity involved in the Touchpoints project and the nature of the interaction with ratepayers, however, I believe a portion of the project costs will qualify for the R&D tax credit under the safe harbor provision. Thus, I believe PGE will be able to claim 25% of the cost of the Touchpoints project as contract research expenditures when calculating its R&D tax credit. Given that the project costs $130,571,018, it must contain elements which are highly technical, requiring innovative solutions to address the specific needs of PGE's system and its customers.

**Q. WHAT DO YOU RECOMMEND?**

A. I recommend that PGE engage its tax provider to conduct an R&D tax credit study to review all of the software projects that PGE has placed into service since the new regulations were issued to determine if those projects are eligible to be claimed towards the 25% Safe Harbor.

In this proceeding I propose including a R&D tax credit amount for the Touchpoints project, based on the calculation provided in Exhibit AWEC/201, Page 5. Based on that workpaper I calculate a credit equal to $2,346,688, which equates to a revenue requirement reduction of $3,322,482. The revenue requirement adjustment is larger than the credit amount because it is stated on a post-tax basis, and similar to production tax credits, must be grossed up using the conversion factor to determine the pre-tax revenue requirement value.

**d. UE 283 Incentives Adjustment**

**Q. PLEASE DESCRIBE THE INCENTIVES ADJUSTMENT TO RATE BASE THAT WAS STIPULATED IN DOCKET UE 283.**

A. In Docket UE 283, it was determined that PGE had improperly capitalized past incentives expenditures, which are traditionally not considered for ratemaking in Oregon. To resolve that issue, PGE agreed to a $10,000,000 reduction to rate base, which was to be amortized, as a benefit, to results over a 20-year period.

**Q. DID PGE CONSIDER THAT AMORTIZATION IN THIS CASE?**

A. No. PGE reduced rate base for this settlement adjustment, but did not consider the corresponding $500,000 of annual amortization. PGE confirmed this error in response to AWEC Data Request 121.

**Q. WHAT IS THE IMPACT OF THIS CORRECTION?**

A. Incorporating the amortization of the incentives adjustment into revenue requirement results in a $507,906 reduction to revenue requirement, after considering revenue sensitive costs.

**e. Dispatchable Generation Regulatory Asset**

**Q. WHAT REGULATORY ASSET HAS PGE INCLUDED WITH RESPECT TO DISPATCHABLE GENERATION?**

A. PGE included a regulatory asset in rate base in the amount of $11,818,000 associated with dispatchable generation. In AWEC Data Request 122, PGE was requested to provide further clarification of what this amount represents. PGE responded that PGE's Dispatchable Standby Generation ("DSG") program pays participating customers owning large, diesel-powered generators for fuel and routine maintenance costs in exchange for access to generator output during times when the PGE grid needs extra power.[24/]

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[24/] Exhibit AWEC/205 at 31 (PGE Resp. to AWEC DR 122).

**Q. DID YOU REQUEST THAT PGE IDENTIFY THE ORDER WHERE THIS PURPORTED REGULATORY ASSET WAS APPROVED?**

A. Yes. In AWEC Data Request 122, PGE suggested that this regulatory asset was approved in Docket No UE 115, PGE's 2001 GRC, on page 11 of Order 01-777.

**Q. DID YOU REVIEW THAT ORDER?**

A. Yes. However, I have not identified anywhere in that order where a regulatory asset associated with dispatchable generation as described by PGE was approved.

**Q. DID YOU REVIEW PGE'S CALCULATION UNDERLYING THE REGULATORY ASSET BALANCE?**

A. Yes. PGE provided Confidential Attachment A to AWEC Data Request 122.[25/] That workpaper, however, contained only hard coded outputs from the System Planner model and did not provide any meaningful information that could be used to determine how the regulatory asset balance was calculated.

**Q. WHAT IS YOUR RECOMMENDATION?**

A. I have identified no evidence that a regulatory asset associated with dispatchable standby generation is appropriately in rate base. Further, PGE has been unable to identify what historical costs have been included in this asset. Accordingly, I recommend that the dispatchable generation regulatory asset be removed from rate base.

**Q. WHAT IS THE IMPACT OF YOUR RECOMMENDATION?**

A. Removing the dispatchable generation regulatory asset results in a $11,818,000 reduction to rate base, and a corresponding, $1,221,446 reduction to revenue requirement.

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25/ Id.

**f. Boardman Severance Payments**

**Q. WHAT ISSUE HAVE YOU IDENTIFIED WITH RESPECT TO BOARDMAN SEVERANCE PAYMENTS?**

A. In response to AWEC Data Request 01, PGE's workpaper showed that it is increasing the depreciation reserves for the amount of amortization through the Schedule 145 that is attributable to Boardman severance payments. PGE has been undertaking this practice since the severance amount of $2,266,836 per year was included in annual adjustments to the reserve balance in July 2015. By October 31, 2018, the accumulated balance of these funds is $5,289,276.

**Q. WHY IS PGE MAKING THIS ADJUSTMENT?**

A. If I understand correctly, PGE includes the amortization of Schedule 145 revenues attributable to decommissioning costs in its accumulated reserve balance. Unlike the decommissioning expense, however, PGE is not allowed to include the severance accrual in the plant balance for accounting purposes, and thus, is removing those balances from the reserve balance.

**Q. WHERE ARE THE BALANCES RELATED TO SEVERANCE PAYMENTS BEING TRACKED?**

A. Order 11-242 in Docket No. UE 230 did not describe whether a carrying charge should accrue on the revenues collected to cover incremental decommissioning expenses through Schedule 145, or whether those balances should be tracked as an offset to rate base. By including the incremental reserve accumulation associated with the decommissioning revenues in the net plant balance, it was my understanding that the funds collected under Schedule 145 were being considered in rate base. Since PGE is applying an adjustment to remove the amounts collected for severance payments, however, the portion of the Schedule 145 revenues attributable to the severance payments are not being considered in net plant and ratepayers are not receiving any carrying charge on those balances.

**Q. WHAT DO YOU RECOMMEND?**

A. I recommend that PGE establish a separate reserve sub-account to house the accumulated Boardman severance revenues, and apply that account as an offset to rate base.

**Q. WHAT IS THE REVENUE REQUIREMENT IMPACT OF THIS RECOMMENDATION?**

A. Reclassifying the accumulated severance payment reserves into rate base results in a $546,671 reduction to revenue requirement.

## VI. PERMANENT DIRECT ACCESS PROGRAM

**Q. PLEASE SUMMARIZE YOUR TESTIMONY ON PGE'S DIRECT ACCESS PROGRAM.**

A. Beginning on Exhibit PGE/1300, Page 36, Line 7, PGE describes a number of changes to its Permanent Direct Access program (also known as its long-term opt-out program). Just like Oregon's Renewable Portfolio Standard ("RPS") and energy efficiency policies, direct access plays an important role in Oregon's state energy policy. The specific changes PGE has proposed, however, would have the effect of invalidating the permanent direct access program, and therefore, should not be adopted. Unlike the program of other electric utilities in the state, PGE's permanent direct access program has been successful, and for that reason, it is not necessary to make sweeping changes at this time. In terms of an overall ratemaking policy, my view is that a primary focus should be to provide departing ratepayers with an appropriate price signal, while protecting non-participating customers. If a customer can depart from the utility's system to free-up capacity on the growing utility's system, that should be viewed as a positive, particularly when the departing customer may procure power with preferred environmental attributes.

**Q. PLEASE SUMMARIZE YOUR RECOMMENDATION.**

A. My recommendation has three elements. First, I recommend that the existing cap on PGE's permanent direct access program be eliminated. Second, I recommend that the Commission decline to approve the 10-year transition adjustment period proposed by PGE. Third, I recommend that the calculation of the transition adjustment be modified to consider the value of freed-up capacity when PGE is in a capacity-short position.

### a. <u>Permanent Direct Access Program and PGE's Proposed Changes</u>

**Q. PLEASE PROVIDE SOME BACKGROUND ON PGE'S PERMANENT DIRECT ACCESS PROGRAM.**

A. PGE's permanent direct access program has been in place since 2002.[26/] While it has undergone some modifications since then, its basic structure remains the same. Customers with loads of at least one average MW ("aMW") have the option to leave the Company's cost of service rates permanently by paying five years of transition charges, which represent the fixed generation costs stranded by the customer's departure, minus the value of energy freed-up also by that departure. Customers may also return to cost-of-service rates by providing at least three years' notice. Prior to development of PGE's long-term opt-out program, direct access, and the Legislature's goal expressed in statute to develop a working competitive electricity market, was entirely unsuccessful.

PGE's long-term opt-out program has benefitted customers and Oregon's energy policy in a number of ways. It has provided an additional option to the Company's largest customers

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[26/] <u>See</u> PGE Adv. 02-17.

who are the most sophisticated about their energy use and, therefore, have the means to operate successfully on the open market, all while protecting non-participating customers from undue cost-shifts. It has furthered state energy policy, as many direct access customers pursue corporate sustainability goals and purchase renewable energy above and beyond what they would be required to purchase under Oregon's RPS. It has also benefitted the state economically by providing a low-cost alternative to Oregon's energy-intensive industries that operate in competitive global markets.

**Q. HOW DOES PGE PROPOSE TO MODIFY ITS PERMANENT DIRECT ACCESS PROGRAM IN THIS CASE?**

A. PGE proposes one major change to this program and another that targets energy service suppliers ("ESSs"). Specifically, it proposes to extend the period over which it collects transition charges (or credits) from customers from five years to ten.[27/] It also proposes that ESSs be decertified with the Commission to operate in Oregon if they fail to schedule with a certain degree of accuracy.[28/] While my testimony focuses primarily on the transition period, I would note here that PGE has failed to provide any evidence that an ESSs' failure to schedule accurately, even if it does occur, impacts its ability to reliably serve its load or harms its customers in any way. Like anyone, ESSs are subject to imbalance charges if they inaccurately schedule to ensure PGE is made whole.

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27/ PGE/1300 at 40.
28/ Id.

### b. Transition Period

**Q. WHAT IS THE BASIS FOR PGE'S PROPOSAL TO CALCULATE TRANSITION CHARGES OVER TEN YEARS?**

A. The sole basis for this change appears to be PGE's desire to align its program with that of PacifiCorp's, which includes ten years' worth of transition payments over a five-year period.[29/]

PGE does present a one-page exhibit (PGE/1308) that purports to show the impact of a departing direct access customer on its system over a ten-year period, but this can hardly be said to provide evidence that a ten-year transition period is reasonable. This exhibit fails to account for load growth that offsets load lost from a departing customer; fails to consider the value PGE receives from freed-up energy <u>and</u> freed-up capacity as a consequence of the departing customer; and fails to provide any support for a finding that ten years' worth of transition charges is any more or less reasonable than any other number of years. In fact, one could simply extend the period PGE's exhibit covers out forever and it would be just as valid as the ten-year view it has chosen to provide.

**Q. IS PGE RIGHT TO RELY ON PACIFICORP FOR A TEN-YEAR TRANSITION CHARGE?**

A. No. PacifiCorp is a multi-state utility and its circumstances are unique from PGE's. One of the reasons why the Commission adopted a ten-year transition period for PacifiCorp had to do with the multi-state protocol ("MSP"), which governs cost allocations between five of PacifiCorp's regulatory jurisdictions, including Oregon. Under Section X of the 2010 Protocol, direct access loads were required to be included when allocating costs to Oregon. Thus, much of the cost-shifting at issue in PacifiCorp's case was unavoidable due to the structure of the MSP agreement that was in effect at the time. The same is not true for PGE.

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[29/] <u>Id.</u>

**Q. WHAT DO YOU RECOMMEND WITH RESPECT TO THE TRANSITION PERIOD?**

A. Absent a compelling reason to change the transition period, the status quo should be maintained as it has proven to be the only workable and successful direct access program the Commission has adopted. As noted above, while PGE seems to imply that its current long-term opt-out program with five years of transition charges results in undue cost-shifting to non-participating customers, it has failed to produce any credible evidence to support this claim. The Commission should not fix what is not broken without an evidentiary basis demonstrating harm from this program, particularly considering the clear benefits this program provides to participating customers and to the state.

### c. <u>Program Cap</u>

**Q. WHAT DOES PGE PROPOSE WITH RESPECT TO A CAP ON DIRECT ACCESS PARTICIPATION?**

A. The current program contains a 300 aMW cap on the amount of load that may participate in the permanent direct access program. PGE's filing does not address this cap, indicating that it proposes no change to it. With approximately 240 aMW of capacity enrolled in the program, however, only about 60 aMW of additional load is eligible to participate.

**Q. HAS THE CAP BEEN PROBLEMATIC FOR SCHEDULE 90 CUSTOMERS?**

A. Yes. Based on the way that the cap was designed, customers on Schedule 90 have been ineligible to participate in the direct access program because the customers' load exceeds the total remaining cap level.

**Q. WHAT DO YOU PROPOSE?**

A. I propose eliminating the cap altogether. As the new load direct access program the Commission is currently considering in AR 614 demonstrates, a cap can be useful to ensure that unanticipated impacts do not occur from a new and untested program. PGE's long-term opt-out program, however, is not new and untested – it has been in place for nearly 16 years. In that time, no party has ever offered evidence demonstrating negative impacts from this program, either to participating customers, non-participating customers, or state policies the Commission is charged with promoting. Indeed, as noted above, this program furthers such policies by helping to implement a competitive market and driving additional renewables development.

**Q. DO YOU EXPECT THAT LARGE NUMBERS OF CUSTOMERS WILL LEAVE FOR DIRECT ACCESS WITHOUT A CAP IN PLACE?**

A. There is no reason to believe so. The same 300 aMW cap has been in place since the inception of PGE's permanent direct access program and it has not been reached yet. Eliminating the cap will simply provide all large non-residential customers with equal access to this program.

**d. <u>Cost of Freed-up Capacity</u>**

**Q. HOW DOES PGE CALCULATE THE TRANSITION ADJUSTMENT PAYMENTS CURRENTLY?**

A. PGE uses a market-minus approach to calculate transition adjustments. Using this approach the transition adjustment payments are calculated based on the difference between the total amount of embedded production costs allocable to the departing customer, less the value of the energy freed-up by the departing customer. The value of the freed-up energy is assumed to equal the market prices input into PGE's MONET model. Under PGE's current approach, the non-power cost portion of the transition adjustment is updated on a year-to-year basis through the transition period, while the value of the freed-up energy is held static.

**Q. DO DEPARTING DIRECT ACCESS CUSTOMERS PROVIDE BENEFITS BEYOND THE VALUE OF FREED-UP ENERGY?**

A. Yes. In addition to freeing up energy, which can be sold into the market, or used to serve other customers, departing customers free up capacity and enable the utility to avoid constructing new generation resources.

**Q. DOSE PGE'S CALCULATION CONSIDER THE VALUE OF FREED-UP CAPACITY?**

A. No.

**Q. DO OTHER UTILITIES CONSIDER THE VALUE OF FREED-UP CAPACITY WHEN CALCULATING TRANSITION ADJUSTMENTS?**

A. Yes. In the case of Microsoft's decision to permanently opt-out of the cost of service rates for Puget Sound Energy ("Puget"), freed-up capacity costs were considered in the transition adjustment calculation.[30/] In fact, in all years after the fourth year of the analysis used to calculate the impact of Microsoft's departure, that departure provided a net benefit to remaining customers as a result of this freed-up capacity. The reason was because, after this fourth year, Puget was projected to be in a capacity-short position due to the retirement of Colstrip Units 1 and 2.

**Q. WILL A CREDIT FOR FREED-UP CAPACITY SEND AN APPROPRIATE PRICE SIGNAL TO DEPARTING CUSTOMERS?**

A. Yes. Similar to the justification for the marginal generation cost study, which is designed to provide a long-term price signal associated with the energy and capacity that customers acquire, it is appropriate to include the value of freed-up capacity in the calculation of the transition adjustment. If generation costs were allocated between demand and energy based on short-term fixed and variable costs—as done in the market minus calculation—much fewer

[30/] WUTC Docket UE-161123, Exh. JAP-1T at 4:1-6:13 (Oct. 7, 2016).

costs would be allocated to high load factor rate classes. The marginal cost study, however, focuses on the long-term cost of demand and energy, recognizing that many costs which are fixed in the short term can be considered variable when viewed in the long term.

**Q. HOW SHOULD THE VALUE OF FREED-UP CAPACITY BE CALCULATED?**

A. The value of freed up capacity should be calculated based on the marginal cost of capacity assumed in PGE's generation marginal cost study. In PGE's initial filing, the marginal cost of capacity was $106.42/kW-yr, which should be applied as a credit, based on the demand of the departing customer, in the transition adjustment calculation.

**Q. HOW SHOULD PGE IDENTIFY WHEN CUSTOMERS RECEIVE A CREDIT FOR FREED-UP CAPACITY?**

A. I recommend that PGE modify Schedule 129 to include a demarcation similar to its resource sufficiency/deficiency date in Schedule 201 for qualifying facilities. This demarcation would identify the date on which the Company is anticipated to be capacity short, which would be based on its most recent Integrated Resource Plan ("IRP"). Also like Schedule 201, PGE would be able to update its capacity short demarcation date immediately following acknowledgement of its most recent IRP. Customers who elect PGE's long-term opt-out program within five years of the demarcation date would receive capacity credits in the years that PGE is capacity short. Notably, this method also ensures that PGE will include direct access as a capacity resource in its long-term planning, thereby reducing costs for all customers (and potentially providing incremental environmental benefits) as future capacity additions are avoided.

## VII. OTHER RATE CASE ISSUES

### a. Major Storm Balancing Account

**Q. WHAT HAS PGE PROPOSED WITH RESPECT TO LEVEL III STORM COSTS.**

A. As described at PGE/800 beginning on Page 13, PGE discusses its proposal to convert the level III storm accrual into a balancing account.

**Q. DO YOU AGREE WITH PGE'S PROPOSAL?**

A. No. PGE has not established the need for a balancing account. I recommend that the current method for Level III storm costs be retained.

**Q. WHAT IS THE CURRENT RATEMAKING MECHANISM USED FOR LEVEL III STORMS?**

A. The current mechanism was established through Order 10-478 in Docket No. UE 215. That method provides PGE with recovery of Level III storm costs using a 10-year rolling average, adjusted for the time value of money. The use of this method has the effect of smoothing the utility's recovery for major storms over time, rather than subjecting ratepayers to rate increases in years with a large magnitude of storm costs.

**Q. DOES THE CURRENT METHOD PROVIDE PGE WITH THE OPPORTUNITY TO RECOVER LEVEL III STORM COSTS?**

A. Yes. The use of a 10-year rolling average is a long-term method of deferred accounting. If the utility incurs relatively high Level III storm costs in any particular year, it is provided with the opportunity to recover those costs through an increase in the rolling average. As time progresses, the year with relatively high Level III storm costs will remain in the average calculation and provide the utility with full recovery for the costs incurred in that year. Additionally, PGE receives the benefit of years in which its Level III storm costs are lower than the ten-year average.

**Q. IS IT APPROPRIATE TO INCLUDE A ROLLING ACCRUAL AND A BALANCING ACCOUNT?**

A. No. If it was decided to change the methodology and begin using a balancing account, it would not be appropriate to continue to use the 10-year rolling average to establish base rates.

**Q. DO YOU HAVE AN EXAMPLE TO DEMONSTRATE WHY IT IS NOT APPROPRIATE TO USE BOTH METHODOLOGIES?**

A. In 2017, PGE incurred Level III storm costs of $11,351,424. Using the rolling 10-year method, PGE accrues $2,600,000 per year. Thus, PGE would collect an additional $8,751,424 through the balancing account. Notwithstanding, the accrual rate also increased by $1,214,696 in 2018 to $3,814,696. Thus, under PGE's approach, the balancing account would provide PGE with the ability to collect the cost of the 2017 storms twice, once through the balancing account and again through the 10-year average calculation. If a balancing account is to be used, it is necessary to reset the initial collections to zero.

**Q. IS PGE COMPARABLE TO THE OTHER UTILITIES IT CITES AS HAVING STORM TRACKERS?**

A. No. I have experience working on cases with Entergy Arkansas, and PGE's need for a storm tracker is not the same as Entergy's. Entergy provides services in an area of the country that has experienced major hurricanes and tornado outbreaks. The risks and costs involved with Hurricane Katrina, for example, are not the same type of weather risk we experience in the Northwest.

**Q. DO YOU AGREE WITH PGE'S CALCULATION OF THE 10-YEAR AVERAGE LEVEL III STORM COSTS?**

A. I've noted one minor correction to the calculation. As noted in Exhibit PGE/801, PGE escalates the Level III storm cost through the end of 2019 when calculating the average. I recommend applying the inflation factor through the end of 2018 and eliminating the 2019 escalation. Removing the 2019 escalation results in a $89,771 reduction to the accrual. Other than this minor correction, I do not oppose PGE's calculation.

### b. Customer Touchpoints Deferral

**Q. PLEASE SUMMARIZE THE DEFERRALS THAT PGE HAS REQUESTED WITH RESPECT TO ITS O&M ON THE CUSTOMER TOUCHPOINTS PROJECT.**

A. In Exhibit PGE/900, Page 15, lines 3 through 10, PGE identifies incremental O&M expenses associated with the Customer Touchpoints project between the "go-live" date and January 1, 2019, and requests that those costs be subject to deferral. Further, in its application filed in Docket No. UM 1948 on May 11, 2018, PGE requested the ability to defer the incremental capital and O&M costs associated with the Customer Touchpoints project between the go-live date and January 1, 2019.

**Q. ARE THOSE AMOUNTS APPROPRIATELY DEFERRED?**

A. No. PGE recently concluded a rate case to establish rates for 2018, and its information technology costs for 2018 were reviewed in that proceeding. In addition, it is questionable whether it is permissible for the return on a capital expenditure to be subject to deferred accounting. PGE is seeking to be relieved of any regulatory lag associated with this project, which as AWEC and CUB's briefing in UM 1909 has shown, improperly alters the balance inherent in ratemaking against customers, particularly with respect to depreciable capital assets like the Touchpoints project.[31/]

[31/] Docket No. UM 1909, Joint Opening Brief of CUB, ICNU and NWIGU at 6-9 (Mar. 16, 2018).

### c. Renewable Adjustment Clause

**Q. WHAT CHANGE DOES PGE PROPOSE TO MAKE TO SCHEDULE 122, ITS RAC?**

A. PGE proposes to add energy storage to the RAC. The RAC is an automatic adjustment clause ("AAC") authorized pursuant to ORS 469A.120(2) that allows for "timely recovery" of prudently incurred costs to meet the RPS. Senate Bill ("SB") 1547, passed in 2016, amended this section to allow recovery of "associated energy storage" with renewable energy facilities through the RAC.[32/]

**Q. IS PGE'S PROPOSAL TO RECOVER ENERGY STORAGE COSTS THROUGH THE RAC CONSISTENT WITH THE LANGUAGE IN SB 1547?**

A. While I am not a lawyer, I do not believe so. PGE's proposed revisions to Schedule 122 simply add the words "energy storage" to the category of items recoverable under that AAC, meaning that any energy storage project would be eligible for the RAC, regardless of whether it was "associated" with a renewable energy project.

**Q. DOES PGE EXPLAIN ITS PROPOSAL TO RECOVER ALL ENERGY STORAGE COSTS THROUGH THE RAC?**

A. Yes. PGE states that "[a]ny energy storage facility on the system controlled by PGE provides integrating renewable energy resources as a primary system benefit."[33/] Thus, PGE's position appears to be that all energy storage is "associated" with renewable energy because it all helps to integrate that renewable energy in some manner.

**Q. IS THIS A DEFENSIBLE POSITION?**

A. No. PGE's apparent definition of the word "associated" in SB 1547 is far too overbroad. Its response to AWEC Data Request 039 demonstrates this. In that request, PGE was asked

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32/ SB 1547 § 11(2)(a).
33/ PGE/1300 at 33:12-14.

whether its various generating resources – Port Westward 1 and 2, Carty, Beaver, Coyote Springs, and its hydro generation – also provide "integrating renewable energy resources as a primary system benefit." And PGE agreed that they do: "PGE considers load balancing to be a primary system benefit of its resource portfolio as a whole, which includes the generating facilities identified above."[34/] Thus, for PGE, every resource on its system is "associated" with renewable energy, which is the same thing as saying that the word "associated" is superfluous in the statute. I do not believe the Legislature intended this result.

**Q. WHAT DO YOU RECOMMEND?**

A. SB 1547 clearly allows for recovery of "associated energy storage" through the RAC. I therefore recommend that PGE be allowed to revise Schedule 122 to include this exact phrase, and not simply "energy storage" as it has proposed. What qualifies as "associated" energy storage should be resolved at a later date – either when PGE seeks to include an energy storage project in the RAC or in the Commission's ongoing RPS rulemaking, AR 610 – where a better record for decision-making can be developed.

**Q. DOES THIS CONCLUDE YOUR OPENING TESTIMONY?**

A. Yes.

34/ Exhibit AWEC/205 at 10 (PGE Resp. to AWEC DR 039).

**BEFORE THE PUBLIC UTILITY COMMISSION**

**OF OREGON**

**UE 335**

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

**EXHIBIT NO. AWEC/201**

**REVENUE REQUIREMENT CALCULATIONS**

**Portland General Electric Corporation**

*Electric Revenue Requirement Summary ($000)*

*In Thousands*

| | | | Cumulative Results | | | 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 | 294,550 | 4,856,160 | 85,812 | | | | |
| 2 | A1 | Cost of Capital | 294,550 | 4,856,160 | 85,015 | - | - | - | (797) |
| *Tax Cuts And Jobs Act* | | | | | | | | | |
| 3 | A2 | Composite Tax Rate Correction | 295,334 | 4,856,160 | 83,768 | | *784* | - | (1,247) |
| 4 | A3 | EDFIT Correction | 296,439 | 4,856,160 | 82,204 | | *1,105* | - | (1,564) |
| 5 | A4 | EDFIT Alternative Method | 296,994 | 4,864,830 | 82,314 | | *555* | *8,670* | 111 |
| 6 | A5 | Interim Period Deferral Amortization | 330,834 | 4,864,830 | 34,403 | *46,255* | *33,840* | - | (47,912) |
| *Capital Expenditures* | | | | | | | | | |
| 7 | A6 | Rate Base Measurement Date | 330,834 | 4,752,752 | 22,819 | - | - | *(112,078)* | (11,584) |
| 8 | A7 | Field Voice Communications / Spectrum | 330,834 | 4,716,803 | 19,103 | - | - | *(35,949)* | (3,715) |
| 9 | A8 | Project Specific Adjustments | 330,834 | 4,715,069 | 18,924 | - | - | *(1,733.90)* | (179) |
| 10 | A9 | Non-Discrete Capital Additions | 330,834 | 4,688,743 | 16,203 | - | - | *(26,326)* | (2,721) |
| *Accumulated Deferred Taxes* | | | | | | | | | |
| 11 | A10 | PTC Carry Forwards | 330,834 | 4,619,253 | 9,021 | - | - | *(69,490)* | (7,182) |
| 12 | A11 | Accrued Vacation | 330,834 | 4,614,411 | 8,521 | - | - | *(4,842)* | (500) |
| 13 | A12 | Stock Incentive Plan | 330,834 | 4,610,908 | 8,159 | - | - | *(3,502)* | (362) |
| 14 | A13 | Boardman Severance | 330,834 | 4,608,134 | 7,872 | - | - | *(2,775)* | (287) |
| 15 | A14 | Injuries and Damages | 330,834 | 4,605,695 | 7,620 | - | - | *(2,439)* | (252) |
| *Other Revenue Requirement Issues* | | | | | | | | | |
| 16 | A15 | Depreciation Reserve | 330,834 | 4,585,895 | 5,573 | - | - | *(19,800)* | (2,046) |
| 17 | A16 | Trojan NDT Amortization | 331,346 | 4,585,895 | 4,848 | *700* | *512* | - | (725) |
| 18 | A17 | Touchpoints R&D Tax Credit | 333,693 | 4,585,895 | 1,526 | | *2,347* | - | (3,322) |
| 19 | A18 | UE 283 Incentives Adjustment | 334,058 | 4,585,895 | 1,008 | *500* | *366* | - | (518) |
| 20 | A19 | Dispatchable Generation Regulatory Asset | 334,058 | 4,574,077 | (214) | - | - | *(11,818)* | (1,221) |
| 21 | A20 | Boardman Severance | 334,058 | 4,568,788 | (760) | - | - | *(5,289)* | (547) |
| 22 | A21 | Level III Storm Escalation | 334,124 | 4,568,788 | (853) | *90* | *66* | - | (93) |
| *Impact of adjustments Sponsored by Dr. Helman* | | | | | | | | | |
| 23 | A22 | Employee Costs | 352,747 | 4,556,974 | **(28,440)** | *25,454* | *18,622* | *(11,814)* | (27,587) |
| | | | | | ***Total Adjustments:*** | ***72,999*** | ***58,196*** | ***(299,186)*** | ***(114,252)*** |

# Portland General Electric Company
## Blended Statutory Income Tax Rate
## Tax Return Data Through 2016

| | Tax Rate | nt % (4-Year Average) | Apportioned Tax Rate |
|---|---|---|---|
| **Federal Income Tax Rate** | 21.00% | 100.0000% | 21.0000% |
| | | | |
| **State\Local** | | | |
| Local | | | |
| Multnomah County Income Tax | 1.45% | 31.9268% | 0.4629% |
| Portland City Income Tax | 2.20% | 0.7411% | 0.0163% |
| Local Total | 3.65% | 32.6679% | 0.4792% |
| Local Federal Offset | | | -0.1006% |
| Local Oregon Offset | | | -0.0345% |
| Local Offset | | | -0.1351% |
| Local net of federal and Oregon benefit | | | 0.3441% |
| | | | |
| Oregon | 7.60% | 94.7394% | 7.2002% |
| Oregon Offset | | | -1.5048% |
| Oregon net of federal benefit | | | 5.6954% |
| Montana Income Tax | 6.75% | 2.7846% | 0.1880% |
| Montana Offset | | | -0.0395% |
| Montana net of federal benefit | | | 0.1485% |
| California Income Tax | 8.84% | 2.0006% | 0.1769% |
| California Offset | | | -0.0371% |
| California net of federal benefit | | | 0.1397% |
| Total State | | | 5.9836% |
| Total State & Local | | | 6.3277% |
| | | | |
| **Blended Statutory Rate** | | | 27.3277% |
| **Less Multnomah** | | | -0.4629% |
| **Composite Rate** | | | 26.8648% |

| State Tax Rate Calculation- Apportionment Factors | 2013 | 2014 | 2015 | 2016 | 4-Year Average |
|---|---|---|---|---|---|
| Multnomah County | 34.1897% | 33.9376% | 31.9390% | 27.6407% | **31.9268%** |
| Portland | 0.7128% | 0.9737% | 0.7882% | 0.4897% | **0.7411%** |
| Oregon | 95.3421% | 94.3375% | 94.6150% | 94.6630% | **94.7394%** |
| Montana | 3.0341% | 2.8727% | 2.6566% | 2.5749% | **2.7846%** |
| California | 1.4437% | 1.9993% | 1.9200% | 2.6393% | **2.0006%** |

**Portland General Electric Corporation**
*EDFIT Calculation using Alternative Method*

| Line | Description | Source | Value |
|---|---|---|---|
| 1 | Property Related ADFIT | AWEC DR 10 | 754,070,950 |
| 2 | Old Composite Tax Rate | Exhibit AWEC 202 | 39.81% |
| 3 | Book Tax Difference Amount | Line 1 / Line 2 | 1,894,409,624 |
| 4 | New Composite Tax Rate | Page 2 | 26.84% |
| 5 | ADFIT After Remeasurement | Line 3 * Line 4 | 508,459,543 |
| 6 | EDFIT Gain | Line 1 - Line 5 | 245,611,407 |
| 7 | Composite Depreciation Rate | Depreciation Study | 3.53% |
| 8 | EDFIT Amortization | Line 6 * Line 7 | 8,670,083 |
| 9 | PGE EDFIT Amortization | AWEC DR 17 | 8,115,311 |
| 10 | Delta (Post-Tax) | Line 8 - Line 9 | 554,772 |

**Portland General Electric Company**

*Deferral Amortization for Excess Taxes Collected in Rates Over the Period January 1, 2018 through December 31, 2018*

*Dollars*

| Month | Beg Balance | Amortization | Interest Rate | Interest | Ending Balance | |
|---|---|---|---|---|---|---|
| 1/1/2019 | 83,066,256 | **(3,854,600)** | 0.75% | 684,040 | 79,895,696 | |
| 2/1/2019 | 79,895,696 | *(3,854,600)* | 0.75% | 660,148 | 76,701,244 | |
| 3/1/2019 | 76,701,244 | *(3,854,600)* | 0.75% | 636,076 | 73,482,720 | |
| 4/1/2019 | 73,482,720 | *(3,854,600)* | 0.75% | 611,823 | 70,239,943 | |
| 5/1/2019 | 70,239,943 | *(3,854,600)* | 0.75% | 587,387 | 66,972,730 | |
| 6/1/2019 | 66,972,730 | *(3,854,600)* | 0.75% | 562,767 | 63,680,897 | |
| 7/1/2019 | 63,680,897 | *(3,854,600)* | 0.75% | 537,961 | 60,364,259 | |
| 8/1/2019 | 60,364,259 | *(3,854,600)* | 0.75% | 512,969 | 57,022,627 | |
| 9/1/2019 | 57,022,627 | *(3,854,600)* | 0.75% | 487,788 | 53,655,815 | |
| 10/1/2019 | 53,655,815 | *(3,854,600)* | 0.75% | 462,417 | 50,263,632 | |
| 11/1/2019 | 50,263,632 | *(3,854,600)* | 0.75% | 436,855 | 46,845,887 | |
| 12/1/2019 | 46,845,887 | *(3,854,600)* | 0.75% | 411,101 | 43,402,388 | |
| 1/1/2020 | 43,402,388 | *(3,854,600)* | 0.75% | 385,152 | 39,932,940 | |
| 2/1/2020 | 39,932,940 | *(3,854,600)* | 0.75% | 359,008 | 36,437,348 | |
| 3/1/2020 | 36,437,348 | *(3,854,600)* | 0.75% | 332,667 | 32,915,415 | |
| 4/1/2020 | 32,915,415 | *(3,854,600)* | 0.75% | 306,127 | 29,366,943 | |
| 5/1/2020 | 29,366,943 | *(3,854,600)* | 0.75% | 279,388 | 25,791,730 | |
| 6/1/2020 | 25,791,730 | *(3,854,600)* | 0.75% | 252,447 | 22,189,577 | |
| 7/1/2020 | 22,189,577 | *(3,854,600)* | 0.75% | 225,303 | 18,560,280 | |
| 8/1/2020 | 18,560,280 | *(3,854,600)* | 0.75% | 197,954 | 14,903,634 | |
| 9/1/2020 | 14,903,634 | *(3,854,600)* | 0.75% | 170,399 | 11,219,433 | |
| 10/1/2020 | 11,219,433 | *(3,854,600)* | 0.75% | 142,637 | 7,507,470 | |
| 11/1/2020 | 7,507,470 | *(3,854,600)* | 0.75% | 114,665 | 3,767,536 | |
| 12/1/2020 | 3,767,536 | *(3,854,600)* | 0.75% | 86,483 | (581) | <-Goal Seek to Zero |
| **Annual Amortization (Pre-tax):** | | **(46,255,200)** | | | | |

**Portland General Electric Company**

*Deferral Amortization for Excess Taxes Collected in Rates Over the Period January 1, 2018 through December 31, 2018*

*Using the Alternative Simplified Credit Calculation*

| Line | Description | Source | Value |
|---|---|---|---|
| 1 | Total Touchpoints Project Cost | AWEC DR 17 | 130,571,018 |
| 2 | 25% Internal Use Safe Harbor | Line 1 * 25% | 32,642,755 |
| 3 | Contract Labor QREs @65% | Line 2 * 65% | 21,217,790 |
| 4 | Historical Qualified Research Expenditures (QREs): | | |
| 5 | 2015 | Note | - |
| 6 | 2016 | \| | - |
| 7 | 2017 | \ | - |
| 8 | 3-year avg | (∑ Lines 5:7 ) / 3 | - |
| 9 | 50% of three year Avg | Line 8 * 50% | - |
| 10 | Excess QREs | Line 3 - Line 9 | 21,217,790 |
| 11 | Apply Credit Rate of 14% | Line 10 * 14% | 2,970,491 |
| 12 | Credit After 280 C | Line 11 * (1-21%) | 2,346,688 |

Note: For purposes of this analysis I have assumed no base period QREs, as I expect those amounts not to be material in the overall calculation

**BEFORE THE PUBLIC UTILITY COMMISSION**

**OF OREGON**

**UE 335**

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

**EXHIBIT NO. AWEC/202**

**IMPACT OF TAX CUTS AND JOBS ACT ON FILING**

**2019 Results of Operations**
**Increase in Base Rates Needed for Reasonable Return**
**Dollars in (000s)**

| | PGE Initial Filing, without TCJA | | | PGE Initial Filing | | | |
|---|---|---|---|---|---|---|---|
| | Base Business | | 9.65% | Base Business | | 4.78% | |
| | 2019 Results at 2018 Base Rates | Change for Reasonable Return | 2019 Results After Change for Reasonable Return | 2019 Results at 2018 Base Rates | Change for Reasonable Return | 2019 Results After Change for Reasonable Return | Revenue Delta |
| | (1) | (2) | (3) | (1) | (2) | (3) | |
| Operating Revenues | | | | | | | |
| Sales to Consumers (Rev. Req.) | 1,798,713 | 173,614 | 1,972,327 | 1,798,713 | 85,908 | 1,884,622 | (87,705) |
| Sales for Resale | - | - | - | - | - | - | |
| Other Operating Revenues | 25,327 | - | 25,327 | 25,327 | - | 25,327 | |
| Total Operating Revenues | 1,824,041 | 173,614 | 1,997,654 | 1,824,041 | 85,908 | 1,909,949 | |
| Operation & Maintenance | | | | | | | |
| Net Variable Power Cost | 375,309 | - | 375,309 | 375,309 | - | 375,309 | |
| Operations O&M | 317,758 | - | 317,758 | 317,758 | - | 317,758 | |
| Support O&M | 265,341 | 1,153 | 266,494 | 265,341 | 571 | 265,911 | |
| Total Operation & Maintenance | 958,407 | 1,153 | 959,561 | 958,407 | 571 | 958,978 | |
| Depreciation & Amortization | 372,496 | - | 372,496 | 372,496 | - | 372,496 | |
| Other Taxes / Franchise Fee | 136,361 | 4,406 | 140,766 | 136,361 | 2,180 | 138,541 | |
| Income Taxes | 102,140 | 67,294 | 169,435 | 62,226 | 22,571 | 84,797 | |
| Total Oper. Expenses & Taxes | 1,569,405 | 72,853 | 1,642,258 | 1,529,491 | 25,322 | 1,554,812 | |
| Utility Operating Income | 254,636 | 100,760 | 355,396 | 294,550 | 60,586 | 355,137 | |
| Rate of Return | 5.242% | | 7.312% | 6.065% | | 7.312% | |
| Return on Equity | 5.361% | | 9.500% | 7.008% | | 9.500% | |

* 2016 Rates per approved UE 294

| | | | | | | |
|---|---|---|---|---|---|---|
| Rate Base | | | | | | |
| Plant in Service | 10,221,818 | - | 10,221,818 | 10,221,818 | - | 10,221,818 |
| Accumulated Depreciation | (4,761,822) | - | (4,761,822) | (4,761,822) | - | (4,761,822) |
| Accumulated Def. Income Taxes | (679,665) | - | (679,665) | (679,665) | - | (679,665) |
| Accumulated Def. Inv. Tax Credit | - | - | - | - | - | - |
| Net Utility Plant | 4,780,331 | - | 4,780,331 | 4,780,331 | - | 4,780,331 |
| Misc Deferred Debits | 9,294 | - | 9,294 | 9,294 | - | 9,294 |
| Operating Materials & Fuel | 78,945 | - | 78,945 | 78,945 | - | 78,945 |
| Misc. Deferred Credits | (74,554) | - | (74,554) | (74,554) | - | (74,554) |
| Working Cash | 63,765 | 2,960 | 66,725 | 62,143 | 1,029 | 63,172 |
| Total Rate Base | 4,857,781 | 2,960 | 4,860,741 | 4,856,160 | 1,029 | 4,857,189 |
| Income Tax Calculations | | | | | | |
| Book Revenues | 1,824,041 | 173,614 | 1,997,654 | 1,824,041 | 85,908 | 1,909,949 |
| Book Expenses | 1,467,265 | 5,559 | 1,472,823 | 1,467,265 | 2,751 | 1,470,015 |
| Interest Rate Base @ Weighted Cost of Debt | 124,435 | 76 | 124,511 | 124,394 | 26 | 124,420 |
| Production Deduction | - | - | - | - | - | - |
| Permanent Sch M Differences | (22,619) | - | (22,619) | (22,619) | - | (22,619) |
| Temporary Sch M Differences | 63,378 | - | 63,378 | 63,378 | - | 63,378 |
| State Taxable Income | 191,582 | 167,979 | 359,561 | 191,623 | 83,131 | 274,755 |
| State Income Tax | 14,917 | 13,080 | 27,997 | 14,921 | 6,473 | 21,394 |
| Federal Taxable Income | 176,664 | 154,899 | 331,564 | 176,703 | 76,658 | 253,361 |
| Fed Income Tax | 61,832 | 54,215 | 116,047 | 37,108 | 16,098 | 53,206 |
| Deferred Taxes | 25,390 | - | 25,390 | 17,208 | - | 17,208 |
| Excess ADIT Reversal (ARAM) | - | - | - | (7,010) | - | (7,010) |
| Federal Tax Credits | - | - | - | - | - | - |
| Total Income Tax | 102,140 | 67,294 | 169,435 | 62,226 | 22,571 | 84,797 |

**General Rate Case - 2019 Test Year**
**Capital Structure / Revenue Sensitive Costs**
**(000s)**

| **Capital Structure:** | **Amount** | **Share** | **Cost** | **Weighted** |
|---|---|---|---|---|
| Common Equity | N/A | 50.00% | 9.500% | 4.750% |
| Preferred | N/A | 0.00% | 0.00% | 0.000% |
| Long-Term Debt | N/A | 50.00% | 5.123% | 2.562% |
| Total | N/A | 100.00% | | **7.312%** |

| **Revenue Sensitive Costs:** | |
|---|---|
| Revenues | 100.0000% |
| OPUC Fees | 0.3211% |
| Franchise Fees | 2.5376% |
| O&M Uncollectibles | 0.3431% |
| State Taxable Income | 96.7982% |
| State and Local Tax @ 7.7865% | 7.5372% |
| Federal Taxable Inc. | 89.2610% |
| Federal Tax @ 21.000% | 31.241354949394500% |
| Total Income Taxes | **38.7785%** |
| Total Rev. Sensitive Costs | **41.9803%** |
| Utility Operating Income | 58.0197% |
| Net To Gross Factor | **1.723554** |

RSC Gross-Up Factor 1.0331

State and Local Income Tax:

| | Appor | Rate | Weighted |
|---|---|---|---|
| Portland | 0.76% | 2.20% | 0.015% |
| Montana | 2.86% | 6.75% | 0.193% |
| California | 2.06% | 8.84% | 0.182% |
| Oregon | 97.32% | 7.60% | 7.396% |
| State and Local Tax Rate | | | 7.786% |

| Less Local Benefit to Oregon: | |
|---|---|
| Oregon Rate | 7.6000% |
| Local Rate | -0.0167% |
| Oregon Benefit of Local Tax deduction | -0.0013% |

Composite Tax Rate: **40.0612%**

| Check: | | |
|---|---|---|
| | Fed Tax | 35.0000% |
| | State Tax | 7.7865% |
| | Tax Shield | -2.7253% |
| | Composite | 40.0612% |

**Income Tax Summary**
**(000s)**

| Income Tax Expense | UE 319 2018 Test Year | 2019 Test Year |
|---|---|---|
| Book Revenues | 1,840,038 | 1,997,654 |
| Book Expenses (including Depreciation) | 1,355,693 | 1,472,823 |
| Interest Deduction | 117,207 | 124,511 |
| Book Taxable Income | 367,138 | 400,320 |
| Production Deduction | 9,000 | - |
| Permanent Sch. M | (24,268) | (22,619) |
| Temporary Sch. M | 45,835 | 63,378 |
| Taxable Income | 336,571 | 359,561 |
| | | |
| Current State Taxes | 26,202 | 27,997 |
| State Tax Credits | - | - |
| Net State Income Tax | 26,202 | 27,997 |
| | | |
| Federal Taxable Income | 310,369 | 331,564 |
| | | |
| Current Federal Taxes | 108,629 | 116,047 |
| | | |
| Federal Tax Credits | - | - |
| ITC Amortization | - | - |
| Deferred Taxes | 18,301 | 25,390 |
| | | |
| Total Income Tax | 153,133 | 169,435 |
| Effective Tax Rate | 41.71% | 42.32% |
| | | |
| Change in Taxes | | 16,302 |
| | | |
| Analysis of Tax Change: | | |
| | | |
| Effective Tax Rate Change | | 0.61% |
| Book Taxable Income (UE 294) | | 367,138 |
| Decrease in Taxes Due to Lower Effective Rate | | 2,258 |
| | | |
| Change in Book Taxable Income (2019 vs UE 319) | | 33,182 |
| 2019 Effective Tax Rate | | 42.32% |
| Decrease in Taxes Due to Lower Book Taxable Income | | 14,044 |
| | | |
| Sum of Tax Impacts | | 16,302 |

**BEFORE THE PUBLIC UTILITY COMMISSION**

**OF OREGON**

**UE 335**

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

**EXHIBIT NO. AWEC/203**

**INTERIM PERIOD DEFERRAL**

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

**FINAL, WITH TAX CUTS AND JOBS ACT (EXCLUDES EDFIT)**

| | Rev Req | Percent |
|---|---|---|
| Total Increase: | (54,931) | -3.08% |

| | At Current Rates | Nov. Load Forecast Delta | GRC Change for RROE | Proposed 2018 | Non-NVPC Adjustments | NVPC Adjustments | Total Results |
|---|---|---|---|---|---|---|---|
| | (1) | (2) | (3) | (4) | (5) | (6) | (7) |
| 1 Sales to Consumers | 1,783,435 | 13,902 | 12,049 | 1,809,386 | (48,747) | (18,233) | 1,742,406 |
| 2 Sales for Resale | - | | | - | - | - | - |
| 3 Other Revenues | 25,841 | | | 25,841 | 1,000 | - | 26,841 |
| 4 Total Operating Revenues | 1,809,276 | | 12,049 | 1,835,227 | (47,747) | (18,233) | 1,769,247 |
| 5 Net Variable Power Costs | 353,586 | | | 353,586 | - | (17,587) | 335,999 |
| 6 Production O&M (excludes Trojan) | 159,768 | | | 159,768 | 154 | - | 159,922 |
| 7 Trojan O&M | 84 | | | 84 | - | - | 84 |
| 8 Transmission O&M | 14,306 | | | 14,306 | - | - | 14,306 |
| 9 Distribution O&M | 120,162 | | | 120,162 | 4 | - | 120,165 |
| 10 Customer & MBC O&M | 75,298 | | | 75,298 | (803) | - | 74,495 |
| 11 Uncollectibles Expense | 6,599 | | 96 | 6,695 | (167) | (63) | 5,978 |
| 12 OPUC Fees | 6,688 | | 97 | 6,785 | (157) | (59) | 5,595 |
| 13 A&G, Ins/Bene., & Gen. Plant | 164,970 | | | 164,970 | (11,805) | - | 153,165 |
| 14 Total Operating & Maintenance | 901,459 | | 193 | 901,652 | (12,774) | (17,709) | 869,708 |
| 15 Depreciation | 317,424 | | | 317,424 | (15,760) | - | 301,665 |
| 16 Amortization | 59,854 | | | 59,854 | (1,399) | - | 58,455 |
| 17 Property Tax | 60,743 | | | 60,743 | - | - | 60,743 |
| 18 Payroll Tax | 16,109 | | | 16,109 | (31) | - | 16,078 |
| 19 Other Taxes | 2,434 | | | 2,434 | - | - | 2,434 |
| 20 Franchise Fees | 45,397 | | 661 | 46,057 | (1,241) | (464) | 44,352 |
| 21 Utility Income Tax | 81,702 | | 6,734 | 88,436 | (3,827) | (11) | 84,787 |
| 22 Total Operating Expenses & Taxes | 1,485,122 | | 7,588 | 1,492,710 | (35,031) | (18,184) | 1,438,223 |
| 23 **Utility Operating Income** | 324,154 | | 18,363 | 342,517 | (12,716) | (49) | 331,024 |
| | | | | 342,517 | | | 331,024 |

**FINAL, WITH TAX CUTS AND JOBS ACT (EXCLUDES EDFIT)**

| | Rev Req | Percent |
|---|---|---|
| Total Increase: | (54,931) | -3.08% |

| | At Current Rates | Nov. Load Forecast Delta | GRC Change for RROE | Proposed 2018 | Non-NVPC Adjustments | NVPC Adjustments | Total Results |
|---|---|---|---|---|---|---|---|
| 24 **Average Rate Base** | | | | | | | |
| 25 Avg. Gross Plant | 9,879,272 | | | 9,879,272 | (62,746) | - | 9,816,526 |
| 26 Avg. Accum. Deprec. / Amort | (4,735,925) | | | (4,735,925) | 7,943 | - | (4,727,981) |
| 27 Avg. Accum. Def Tax | (634,410) | | | (634,410) | (27,861) | - | (662,272) |
| 28 Avg. Accum. Def ITC | - | | | - | - | - | - |
| 29 **Avg. Net Utility Plant** | 4,508,938 | | - | 4,508,938 | (82,664) | - | 4,426,274 |
| | | | | | | | |
| 30 Misc. Deferred Debits | 20,863 | | | 20,863 | (3,923) | - | 16,940 |
| 31 Operating Materials & Fuel | 80,737 | | | 80,737 | - | - | 80,737 |
| 32 Misc. Deferred Credits | (73,318) | | | (73,318) | - | - | (73,318) |
| 33 Working Cash | 53,882 | | 275 | 54,157 | (1,271) | (660) | 52,180 |
| 34 **Average Rate Base** | 4,591,101 | | 275 | 4,591,377 | (87,858) | (660) | 4,502,813 |
| | | | | | | | |
| 35 **Rate of Return** | 7.060% | | | 7.460% | | 7.352% | 7.352% |
| 36 **Implied Return on Equity** | 8.951% | | | 9.750% | | 9.500% | 9.500% |
| | | | | | | | |
| 37 Effective Cost of Debt | 5.170% | | 5.170% | 5.170% | 5.203% | 5.203% | 5.203% |
| 38 Effective Cost of Preferred | 0.000% | | 0.000% | 0.000% | 0.000% | 0.000% | 0.000% |
| 39 Debt Share of Cap Structure | 50.000% | | 50.000% | 50.000% | 50.000% | 50.000% | 50.000% |
| 40 Preferred Share of Cap Structure | 0.000% | | 0.000% | 0.000% | 0.000% | 0.000% | 0.000% |
| 41 Weighted Cost of Debt | 2.585% | | 2.585% | 2.585% | 2.602% | 2.602% | 2.602% |
| 42 Weighted Cost of Preferred | 0.000% | | 0.000% | 0.000% | 0.000% | 0.000% | 0.000% |
| 43 Equity Share of Cap Structure | 50.000% | | 50.000% | 50.000% | 50.000% | 50.000% | 50.000% |
| 44 State Tax Rate | 7.392% | | 7.392% | 7.392% | 7.392% | 7.392% | 7.392% |
| 45 Federal Tax Rate | 21.000% | | 21.000% | 21.000% | 21.000% | 21.000% | 21.000% |
| 46 Composite Tax Rate | 26.840% | | 26.840% | 26.840% | 26.840% | 26.840% | 26.840% |
| 47 Bad Debt Rate | 0.370% | | 0.370% | 0.370% | 0.343% | 0.343% | 0.343% |
| 48 Franchise Fee Rate | 2.545% | | 2.545% | 2.545% | 2.545% | 2.545% | 2.545% |
| 49 Working Cash Factor | 3.628% | | 3.628% | 3.628% | 3.628% | 3.628% | 3.628% |
| 50 Gross-Up Factor | 1.367 | | 1.367 | 1.367 | 1.367 | 1.367 | 1.367 |
| 51 ROE Target | 9.750% | | 9.750% | 9.750% | 9.500% | 9.500% | 9.500% |
| 52 Grossed-Up COC | 9.248% | | 9.248% | 9.248% | 9.094% | 9.094% | 9.094% |
| 53 OPUC Fee Rate | 0.3750% | | 0.375% | 0.375% | 0.321% | 0.321% | 0.321% |

**FINAL, WITH TAX CUTS AND JOBS ACT (EXCLUDES EDFIT)**

| | Rev Req | Percent |
|---|---|---|
| Total Increase: | (54,931) | -3.08% |

| | | At Current Rates | Nov. Load Forecast Delta | GRC Change for RROE | Proposed 2018 | Non-NVPC Adjustments | NVPC Adjustments | Total Results |
|---|---|---|---|---|---|---|---|---|
| | Utility Income Taxes | | | | | | | |
| 54 | Book Revenues | 1,809,276 | | 25,951 | 1,835,227 | (47,747) | (18,233) | 1,769,247 |
| 55 | Book Expenses | 1,403,420 | | 854 | 1,404,274 | (31,204) | (18,173) | 1,353,436 |
| 56 | Interest Deduction | 118,680 | | 7 | 118,687 | (2,286) | (17) | 117,141 |
| 57 | Production Deduction | 9,000 | | | 9,000 | - | | 9,000 |
| 58 | Permanent Ms | (24,268) | | | (24,268) | - | | (24,268) |
| 59 | Deferred Ms | 45,835 | | | 45,835 | - | | 45,835 |
| 60 | Taxable Income | 256,609 | | 25,090 | 281,699 | (14,258) | (43) | 268,104 |
| | | | | | | | | |
| 61 | Current State Tax | 19,635 | | 1,855 | 21,490 | (1,054) | (3) | 20,485 |
| 62 | State Tax Credits | - | | | - | - | | - |
| 63 | Net State Taxes | 19,635 | | 1,855 | 21,490 | (1,054) | (3) | 20,485 |
| | | | | | | | | |
| 64 | Federal Taxable Income | 236,974 | | 23,235 | 260,209 | (13,204) | (40) | 247,619 |
| | | | | | | | | |
| 65 | Current Federal Tax | 49,765 | | 4,879 | 54,644 | (2,773) | (8) | 52,000 |
| 66 | Federal Tax Credits | - | | | - | - | | - |
| 67 | ITC Amort | - | | - | - | - | | - |
| 68 | Deferred Taxes | 12,302 | | 0 | 12,302 | - | - | 12,302 |
| 69 | Total Income Tax Expense | 81,702 | | 6,734 | 88,436 | (3,827) | (11) | 84,787 |
| 70 | Regulated Net Income | 205,474 | | | 223,830 | | | 213,884 |

**FINAL, WITHOUT TAX CUTS AND JOBS ACT**

| | Rev Req | Percent |
|---|---|---|
| Total Increase: | 15,860 | 0.89% |

| | At Current Rates | Nov. Load Forecast Delta | GRC Change for RROE | Proposed 2018 | Non-NVPC Adjustments | NVPC Adjustments | Total Results | **Revenue Delta** |
|---|---|---|---|---|---|---|---|---|
| | (1) | (2) | (3) | (4) | (5) | (6) | (7) | |
| 1 Sales to Consumers | 1,783,435 | 13,902 | 85,995 | 1,883,332 | (51,893) | (18,242) | 1,813,197 | **(70,791)** |
| 2 Sales for Resale | - | | | - | - | - | - | |
| 3 Other Revenues | 25,841 | | | 25,841 | 1,000 | - | 26,841 | |
| 4 Total Operating Revenues | 1,809,276 | | 85,995 | 1,909,173 | (50,893) | (18,242) | 1,840,038 | |
| | | | | | | | | |
| 5 Net Variable Power Costs | 353,586 | | | 353,586 | - | (17,587) | 335,999 | |
| 6 Production O&M (excludes Trojan) | 159,768 | | | 159,768 | 154 | - | 159,922 | |
| 7 Trojan O&M | 84 | | | 84 | - | - | 84 | |
| 8 Transmission O&M | 14,306 | | | 14,306 | - | - | 14,306 | |
| 9 Distribution O&M | 120,162 | | | 120,162 | 4 | - | 120,165 | |
| 10 Customer & MBC O&M | 75,298 | | | 75,298 | (803) | - | 74,495 | |
| 11 Uncollectibles Expense | 6,599 | | 370 | 6,968 | (178) | (63) | 6,221 | |
| 12 OPUC Fees | 6,688 | | 375 | 7,062 | (167) | (59) | 5,822 | |
| 13 A&G, Ins/Bene., & Gen. Plant | 164,970 | | | 164,970 | (11,820) | - | 153,150 | |
| 14 Total Operating & Maintenance | 901,459 | | 744 | 902,203 | (12,810) | (17,709) | 870,163 | |
| | | | | | | | | |
| 15 Depreciation | 317,424 | | | 317,424 | (15,760) | - | 301,665 | |
| 16 Amortization | 59,854 | | | 59,854 | (1,399) | - | 58,455 | |
| 17 Property Tax | 60,743 | | | 60,743 | - | - | 60,743 | |
| 18 Payroll Tax | 16,109 | | | 16,109 | (31) | - | 16,078 | |
| 19 Other Taxes | 2,434 | | | 2,434 | - | - | 2,434 | |
| 20 Franchise Fees | 45,397 | | 2,543 | 47,939 | (1,321) | (464) | 46,154 | |
| 21 Utility Income Tax | 121,190 | | 38,559 | 159,749 | (6,901) | (21) | 153,133 | |
| 22 Total Operating Expenses & Taxes | 1,524,610 | | 41,846 | 1,566,457 | (38,221) | (18,194) | 1,508,826 | |
| 23 **Utility Operating Income** | 284,665 | | 58,051 | 342,716 | (12,672) | (49) | 331,212 | |
| | | | | 342,716 | | | 331,212 | |

**FINAL, WITHOUT TAX CUTS AND JOBS ACT**

| | Rev Req | Percent |
|---|---|---|
| Total Increase: | 15,860 | 0.89% |

| | At Current Rates | Nov. Load Forecast Delta | GRC Change for RROE | Proposed 2018 | Non-NVPC Adjustments | NVPC Adjustments | Total Results | Revenue Delta |
|---|---|---|---|---|---|---|---|---|
| 24 **Average Rate Base** | | | | | | | | |
| 25 Avg. Gross Plant | 9,879,272 | | | 9,879,272 | (62,746) | - | 9,816,526 | |
| 26 Avg. Accum. Deprec. / Amort | (4,735,925) | | | (4,735,925) | 7,943 | - | (4,727,981) | |
| 27 Avg. Accum. Def Tax | (634,410) | | | (634,410) | (27,861) | - | (662,272) | |
| 28 Avg. Accum. Def ITC | - | | | - | - | - | - | |
| 29 **Avg. Net Utility Plant** | 4,508,938 | | - | 4,508,938 | (82,664) | - | 4,426,274 | |
| 30 Misc. Deferred Debits | 20,863 | | | 20,863 | (3,923) | - | 16,940 | |
| 31 Operating Materials & Fuel | 80,737 | | | 80,737 | - | - | 80,737 | |
| 32 Misc. Deferred Credits | (73,318) | | | (73,318) | - | - | (73,318) | |
| 33 Working Cash | 55,314 | | 1,518 | 56,833 | (1,387) | (660) | 54,742 | |
| 34 **Average Rate Base** | 4,592,534 | | 1,518 | 4,594,052 | (87,974) | (660) | 4,505,374 | |
| 35 **Rate of Return** | 6.198% | | | 7.460% | | 7.351% | 7.351% | |
| 36 **Implied Return on Equity** | 7.227% | | | 9.750% | | 9.500% | 9.500% | |
| 37 Effective Cost of Debt | 5.170% | | 5.170% | 5.170% | 5.203% | 5.203% | 5.203% | |
| 38 Effective Cost of Preferred | 0.000% | | 0.000% | 0.000% | 0.000% | 0.000% | 0.000% | |
| 39 Debt Share of Cap Structure | 50.000% | | 50.000% | 50.000% | 50.000% | 50.000% | 50.000% | |
| 40 Preferred Share of Cap Structure | 0.000% | | 0.000% | 0.000% | 0.000% | 0.000% | 0.000% | |
| 41 Weighted Cost of Debt | 2.585% | | 2.585% | 2.585% | 2.602% | 2.602% | 2.602% | |
| 42 Weighted Cost of Preferred | 0.000% | | 0.000% | 0.000% | 0.000% | 0.000% | 0.000% | |
| 43 Equity Share of Cap Structure | 50.000% | | 50.000% | 50.000% | 50.000% | 50.000% | 50.000% | |
| 44 State Tax Rate | 7.582% | | 7.582% | 7.582% | 7.582% | 7.582% | 7.582% | |
| 45 Federal Tax Rate | 35.000% | | 35.000% | 35.000% | 35.000% | 35.000% | 35.000% | |
| 46 Composite Tax Rate | 39.928% | | 39.928% | 39.928% | 39.928% | 39.928% | 39.928% | |
| 47 Bad Debt Rate | 0.370% | | 0.370% | 0.370% | 0.343% | 0.343% | 0.343% | |
| 48 Franchise Fee Rate | 2.545% | | 2.545% | 2.545% | 2.545% | 2.545% | 2.545% | |
| 49 Working Cash Factor | 3.628% | | 3.628% | 3.628% | 3.628% | 3.628% | 3.628% | |
| 50 Gross-Up Factor | 1.665 | | 1.665 | 1.665 | 1.665 | 1.665 | 1.665 | |
| 51 ROE Target | 9.750% | | 9.750% | 9.750% | 9.500% | 9.500% | 9.500% | |
| 52 Grossed-Up COC | 10.700% | | 10.700% | 10.700% | 10.509% | 10.509% | 10.509% | |
| 53 OPUC Fee Rate | 0.3750% | | 0.375% | 0.375% | 0.321% | 0.321% | 0.321% | |

**FINAL, WITHOUT TAX CUTS AND JOBS ACT**

| | Rev Req | Percent |
|---|---|---|
| Total Increase: | 15,860 | 0.89% |

| | | At Current Rates | Nov. Load Forecast Delta | GRC Change for RROE | Proposed 2018 | Non-NVPC Adjustments | NVPC Adjustments | Total Results | **Revenue Delta** |
|---|---|---|---|---|---|---|---|---|---|
| | Utility Income Taxes | | | | | | | | |
| 54 | Book Revenues | 1,809,276 | | 99,897 | 1,909,173 | (50,893) | (18,242) | 1,840,038 | |
| 55 | Book Expenses | 1,403,420 | | 3,287 | 1,406,707 | (31,320) | (18,173) | 1,355,693 | |
| 56 | Interest Deduction | 118,717 | | 39 | 118,756 | (2,289) | (17) | 117,207 | |
| 57 | Production Deduction | 9,000 | | | 9,000 | - | | 9,000 | |
| 58 | Permanent Ms | (24,268) | | | (24,268) | - | | (24,268) | |
| 59 | Deferred Ms | 45,835 | | | 45,835 | - | | 45,835 | |
| 60 | Taxable Income | 256,572 | | 96,571 | 353,143 | (17,284) | (52) | 336,571 | |
| 61 | Current State Tax | 20,136 | | 7,322 | 27,459 | (1,311) | (4) | 26,202 | |
| 62 | State Tax Credits | - | | | - | - | | - | |
| 63 | Net State Taxes | 20,136 | | 7,322 | 27,459 | (1,311) | (4) | 26,202 | |
| 64 | Federal Taxable Income | 236,436 | | 89,249 | 325,684 | (15,974) | (48) | 310,369 | |
| 65 | Current Federal Tax | 82,752 | | 31,237 | 113,989 | (5,591) | (17) | 108,629 | |
| 66 | Federal Tax Credits | - | | | - | - | | - | |
| 67 | ITC Amort | - | | - | - | - | | - | |
| 68 | Deferred Taxes | 18,301 | | 0 | 18,301 | - | - | 18,301 | |
| 69 | Total Income Tax Expense | 121,190 | | 38,559 | 159,749 | (6,901) | (21) | 153,133 | |
| 70 | Regulated Net Income | 165,948 | | | 223,960 | | | 214,005 | |

**BEFORE THE PUBLIC UTILITY COMMISSION**

**OF OREGON**

**UE 335**

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

**EXHIBIT NO. AWEC/204**

**NOTICE OF INTERNAL USE SOFTWARE REGULATIONS**

Dated: September 28, 2016.

**Harriet Tregoning,**

*Principal Deputy Assistant, Secretary for Community Planning and Development.*

[FR Doc. 2016–23986 Filed 10–3–16; 8:45 am]

**BILLING CODE 4210–67–P**

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## DEPARTMENT OF THE TREASURY

### Internal Revenue Service

### 26 CFR Part 1

**[TD 9786]**

**RIN 1545–BC70**

## Credit for Increasing Research Activities

**AGENCY:** Internal Revenue Service (IRS), Treasury.

**ACTION:** Final regulations.

**SUMMARY:** This document contains final regulations concerning the application of the credit for increasing research activities. These final regulations provide guidance on software that is developed by (or for the benefit of) the taxpayer primarily for internal use by the taxpayer (internal use software). These final regulations also include examples to illustrate the application of the process of experimentation requirement to software. These final regulations will affect taxpayers engaged in research activities involving software.

**DATES:** *Effective date:* These regulations are effective on October 4, 2016.

*Applicability date:* For date of applicability see § 1.41–4(e).

**FOR FURTHER INFORMATION CONTACT:** Martha Garcia or Jennifer Records of the IRS Office of the Associate Chief Counsel (Passthroughs and Special Industries) at (202) 317–6853 (not a toll-free number).

**SUPPLEMENTARY INFORMATION:**

### Background

This document contains final regulations that amend the Income Tax Regulations (26 CFR part 1) relating to the credit for increasing research activities (research credit) under section 41 of the Internal Revenue Code (Code). Section 41(d)(4)(E) provides that, except to the extent provided by regulations, research with respect to software that is developed by (or for the benefit of) the taxpayer primarily for internal use by the taxpayer is excluded from the definition of qualified research under section 41(d). Software that is developed for use in an activity that constitutes qualified research for purposes of section 41(d) and software that is developed for use in a production process with respect to which the general credit eligibility requirements under section 41 are satisfied are internal use software, but are not excluded under section 41(d)(4)(E) from the definition of qualified research and are not subject to these regulations.

On January 20, 2015, the Treasury Department and the IRS published in the **Federal Register** (80 FR 2624, January 20, 2015) a notice of proposed rulemaking (REG–153656–03, 2015–5 IRB 566) under section 41 (the proposed regulations) relating to the research credit. Comments responding to the proposed regulations were received and a public hearing was held on April 17, 2015. After consideration of all of the comments received, these final regulations adopt the proposed regulations as revised by this Treasury decision.

### Summary of Comments and Explanation of Provisions

#### I. Definition of Internal Use Software

The proposed regulations provided that software is developed by (or for the benefit of) the taxpayer primarily for internal use if the software is developed by the taxpayer for use in general and administrative functions that facilitate or support the conduct of the taxpayer's trade or business. General and administrative functions, as defined in the proposed regulations, are limited to (1) financial management functions, (2) human resource management functions, and (3) support services functions. Financial management functions are functions that involve the financial management of the taxpayer and the supporting recordkeeping. Human resource management functions are functions that manage the taxpayer's workforce. Support services functions are functions that support the day-to-day operations of the taxpayer, such as data processing or facilities services.

Commenters expressed concern that the list of general and administrative functions in the proposed regulations was overly broad and included functions that do not represent "back-office" functions. In particular, the commenters noted that inventory management, marketing, legal services, and government compliance services can provide significant benefits to third parties and may be developed to enable a taxpayer to interact with third parties or to allow third parties to initiate functions or review data on the taxpayer's system. Specifically, one commenter noted that many inventory management software applications are an integral part of a taxpayer's supply chain management system and can be readily seen as part of the modern "front office." This commenter noted that modern inventory management software usually requires interaction with a number of third party vendors to ensure the correct flow of raw materials and a corresponding flow of finished goods. Additionally, the commenter added that inventory management is inherently customer facing because it provides the proper amount of inventory to customers at the point of sale at the right time. Another commenter added that marketing is an external-facing function by nature, and software that supports marketing is necessarily intended to interact with third parties.

The Treasury Department and the IRS understand that many modern software systems perform more than back-office functions. These software systems commonly provide benefits to vendors and include functions that are customer facing. Additionally, software with functions such as marketing or inventory management may not provide solely back-office functions, but may also contain functions that enable a taxpayer to interact with third parties or to allow third parties to initiate functions or review data on the taxpayer's system. Recognizing such situations, the proposed regulations provided rules under § 1.41–4(c)(6)(iv)(C) (dual function rules) to evaluate whether software that has both back-office and front-office functions is developed primarily for internal use. The Treasury Department and the IRS continue to believe that functions such as inventory management, marketing, legal services, and government compliance services provide support to day-to-day operations of a taxpayer in carrying on business regardless of the taxpayer's industry and that the benefits that such functions may provide to third parties are collateral and secondary. In addition, the Treasury Department and the IRS believe the dual function rules in these final regulations sufficiently address these comments by allowing taxpayers to identify subsets of elements of dual function software that only enable a taxpayer to interact with third parties or allow third parties to initiate functions or review data. Accordingly, the list of general and administrative functions provided in the proposed regulations remains unchanged in the final regulations.

Another commenter referred to the tax software example in the preamble to the proposed regulations which notes that tax software developed by a company engaged in providing tax services to its customers is not used by the taxpayer in general and administrative functions even though tax is listed under § 1.41–4(c)(6)(iii)(B)(*1*) of the proposed regulations, as a general and administrative function. The commenter requested that we make this concept more explicit by revising § 1.41–4(c)(6)(iii)(A) of the proposed regulations and providing additional examples. As discussed in the preamble to the proposed regulations, the list of general and administrative functions is intended to target the back-office functions that most taxpayers would have regardless of the taxpayer's industry, although the characterization of a function as back office will vary depending on the facts and circumstances of the taxpayer. Because § 1.41–4(c)(6)(v) of these final regulations makes clear that the determination of whether software is developed primarily for internal use depends on the intent of the taxpayer and the facts and circumstances at the beginning of software development, the Treasury Department and the IRS believe that additional clarifying language and examples are unnecessary.

**II. Definition of Software Not Developed Primarily for Internal Use**

The proposed regulations provided that software is not developed primarily for internal use only if it is developed to be commercially sold, leased, licensed, or otherwise marketed to third parties, or if it is developed to enable a taxpayer to interact with third parties or to allow third parties to initiate functions or review data on the taxpayer's system. After consideration of the comments described herein, these final regulations clarify that (1) software is not developed primarily for the taxpayer's internal use if it is not developed for use in general and administrative functions that facilitate or support the conduct of the taxpayer's trade or business; and (2) software that is developed to be commercially sold, leased, licensed, or otherwise marketed to third parties and software that is developed to enable a taxpayer to interact with third parties or to allow third parties to initiate functions or review data on the taxpayer's system are examples of software that is not developed primarily for the taxpayer's internal use.

*A. Software Developed To Be Commercially Sold, Leased, Licensed or Otherwise Marketed to Third Parties*

A commenter requested that § 1.41–4(c)(6)(iv)(A)(*1*) of the proposed regulations be revised to state that software is not developed primarily for the taxpayer's internal use if the software is developed to be commercially sold, leased, licensed, *hosted,* or otherwise marketed to third parties. (Emphasis added.) The commenter also recommended additional language to further define "otherwise marketed" to include transactions where the taxpayer effectively provides the functionality of the software to a third party even if there is no transfer of a copy of the software itself to such third party. The Treasury Department and the IRS understand that a taxpayer may develop software where the full functionality of that software is provided to a third party even though there is no transfer of a copy of the software. The Treasury Department and the IRS believe the phrase "software that is developed to be commercially sold, leased, licensed or otherwise marketed to third parties" is sufficiently broad to encompass hosted software and other software where there is no transfer of a copy of the software. An example has been added to further illustrate this point (Example 9 of these final regulations).

*B. Software Developed To Enable a Taxpayer To Interact With Third Parties or Allow Third Parties To Initiate Functions or Review Data on the Taxpayer's System*

Several commenters requested clarification on the terms "interact," "initiate," or "review," and recommended additional examples illustrating the terms. One commenter noted that a common example that should be clarified is whether a third party reviewing a Web site constitutes "interaction," "initiate functions," or "review data." In response to these comments, the final regulations clarify that software that is developed to enable a taxpayer to interact with third parties or to allow third parties to initiate functions or review data on the taxpayer's system are examples of software that is not developed primarily for the taxpayer's internal use. In addition, these final regulations provide that the determination of whether software is internal use or developed to enable a taxpayer to interact with third parties or to allow third parties to initiate functions or review data on the taxpayer's system depends on the intent of the taxpayer and the facts and circumstances at the beginning of the software development. Accordingly, Example 3 of the proposed regulations, now designated as Example 4 in these final regulations, is revised to show that software developed with the intent of marketing via a Web site and not to allow third parties to review data on the taxpayer's system is developed for internal use because it was developed for use in a general and administrative function.

**III. Connectivity Software**

In the proposed regulations, the Treasury Department and the IRS requested comments on the appropriate definition and treatment of connectivity software that allows multiple processes running on one or more machines to interact across a network, sometimes referred to as bridging software, integration software, or middleware. The Treasury Department and the IRS received very few responses to this request for comments. One of the commenters noted that the treatment of such software is challenging because of its multi-faceted purposes; it could fall within a category in which it is not sold, does not interact with a third party, and does not perform a general and administrative function. The other commenter recommended that the regulations provide a general rule for connectivity software that is tied to the intent of the taxpayer and the facts and circumstances at the beginning of the software development and that the regulations provide examples demonstrating the rule. In addition, with respect to this category of software, the Treasury Department and the IRS understand that with wide use and availability of enterprise resource planning (ERP) software, few companies actually engage in developing connectivity software. Connectivity software is often purchased or the need for it has diminished due to the use of ERP software.

After further consideration of business practices and the limited comments received, the Treasury Department and the IRS believe that a special rule for connectivity software is not needed. The final regulations clarify that software is not developed by (or for the benefit of) the taxpayer primarily for the taxpayer's internal use if the software is not developed for use in general and administrative functions. Accordingly, any software that is not developed to be used in a general and administrative function will not be considered to be developed for internal use. This is the case even if the software is not developed to be commercially sold, leased, licensed, or otherwise marketed to third parties, or is not developed to enable a taxpayer to interact with third parties or to allow third parties to initiate functions or review data on the taxpayer's system.

Furthermore, connectivity software should not be specifically identified or categorized differently from other types of software. Whether certain software is developed to be used primarily for internal use should be based on the function the software provides, rather than the type of software. For example, connectivity software that is developed to connect a taxpayer's existing payroll software with financial budgeting software to allow an exchange of data between the two software modules would be considered to be developed for the taxpayer's internal use because the connectivity software's function is to be used in human resources and financial management functions. Accordingly, the Treasury Department and the IRS believe that the general rule in the final regulations to determine whether or not software is developed primarily for internal use already provides sufficient guidance for connectivity software. Whether software, including connectivity software, is developed for use in general and administrative functions depends upon the intent of the taxpayer and the facts and circumstances at the beginning of the software development.

**IV. Intent of the Taxpayer and the Facts and Circumstances at the Beginning of the Software Development**

The proposed regulations provided that whether software is or is not developed primarily for internal use depends upon the intent of the taxpayer and the facts and circumstances at the beginning of the software development. If a taxpayer originally develops software primarily for internal use but later makes improvements to the software with the intent to hold the improved software for commercial sale, lease, or license or to allow third parties to initiate functions or review data on the taxpayer's system, the improvements will be considered separate from the existing software and will not be considered developed primarily for internal use. Likewise, if a taxpayer originally develops software for commercial sale, lease, or license or to interact with third parties or to allow third parties to initiate functions or review data on the taxpayer's system, but later makes improvements to the software with the intent to use the software in general and administrative functions, the improvements will be considered separate from the existing software and will be considered developed primarily for internal use. After consideration of the comments described below, these final regulations retain these rules without modification.

A commenter explained that it is common for a taxpayer to initiate a software development project with one purpose in mind and to later discover that other purposes should be considered and pursued. Commenters also explained that it is common for a taxpayer to abandon its original intentions of how the software might be used. Commenters made several different recommendations, among them that the final regulations adopt a standard that allows facts at any point during the software development to be considered. Another suggested looking to the intended use of the software, and not just the improvements, as of the tax return filing date for the taxable year or the beginning of the taxable year in which the software development expenditures were incurred. One commenter further suggested that if the regulations require a determination at the beginning of the software development, the regulations should allow that determination to be rebutted with evidence about how the software is actually used when it is placed in service. Commenters also noted that taxpayers will likely have difficulty substantiating their intended use of the software at the beginning of the development process.

The Treasury Department and the IRS conclude that only a rule that generally requires that a determination be made at the beginning of software development is consistent with the intent and the purpose of section 41. Congress intended that the credit for increasing research activities would provide an incentive for greater private activity in research. That incentive nature of section 41 is promoted by taking into account a taxpayer's intent at the beginning of the software development; allowing any change in a taxpayer's intent throughout the development to support treatment as qualifying research of expenses incurred prior to that change would frustrate the purpose of the credit. Furthermore, allowing a taxpayer to redetermine the overall project's credit eligibility throughout the development which could span multiple years would provide uncertain and inconsistent treatment and impose an undue burden on both taxpayers and the IRS. Finally, the final regulations continue to provide a special rule for improvements to software that can be separately identified. This special rule would apply, for example, when a taxpayer completes a software development and then decides to improve that software by undertaking further development to the same software.

**V. Dual Function Software and Safe Harbor**

*A. Presumption and Third Party Subset*

The proposed regulations provided that software developed by (or for the benefit of) the taxpayer both for use in general and administrative functions that facilitate or support the conduct of the taxpayer's trade or business and to enable a taxpayer to interact with third parties or to allow third parties to initiate functions or review data (dual function software) is presumed to be developed primarily for a taxpayer's internal use. However, this presumption is inapplicable to the extent that a taxpayer can identify a subset of elements of dual function software that only enables a taxpayer to interact with third parties or allows third parties to initiate functions or review data on the taxpayer's system (third party subset). The proposed regulations provided that if the taxpayer can identify a third party subset, the portion of qualified research expenditures allocable to such third party subset of the dual function software may be eligible for the research credit, provided all the other applicable requirements are met.

The Treasury Department and the IRS received several comments on dual function software rules. One commenter recommended changes to clarify that the dual function software rules do not apply to software developed to be commercially sold, leased, licensed, or otherwise marketed to third parties, even if such software was also developed to enable a taxpayer to interact with third parties or to allow third parties to initiate functions or review data on the taxpayer's system.

The Treasury Department and the IRS believe such clarification is unnecessary as § 1.41–4(c)(6)(iv)(C)(*1*) of the proposed regulations clearly defines dual function software as software that is developed by the taxpayer both for use in general and administrative functions and to enable a taxpayer to interact with third parties or to allow third parties to initiate functions or review data. Software that is developed to be commercially sold, leased, licensed, or otherwise marketed to third parties is not dual function software, even if such software was also developed to enable a taxpayer to interact with third parties or to allow third parties to initiate functions or review data on the taxpayer's system.

One commenter suggested that the "substantially all" and "shrink back" rules found in § 1.41–4(b)(2) can be easily applied to evaluate dual function software. If substantially all of the software is non-internal use, then all of the software should be considered non-internal use under the substantially all rule. Similarly, if substantially all of the software is internal use, then the software should be considered internal use. In the case where the software as a whole does not meet the substantially all rule, then the taxpayer would apply the shrink back rule and the software would be divided into subcomponents based on functionality until the non-internal use portion and the internal use portion were appropriately separated. That commenter noted that these two rules have worked for many years with little difficulty in other areas of the research credit rules and could be used equally well to address the issue of dual function software. Another commenter encouraged the addition of a rule to cover cases in which a taxpayer's dual function subset's third party use or interaction exceeds 80 percent. The commenter stated that in this circumstance, the remaining internal use is de minimis and should be disregarded and the entire development should be treated as not developed for internal use.

The shrink back rule provides that the requirements of section 41(d) and § 1.41–4(a) are to be applied first at the level of the discrete business component, that is, the product, process, computer software, technique, formula, or invention to be held for sale, lease, or license, or used by the taxpayer in a trade or business of the taxpayer. If these requirements are not met at that level, then they apply at the most significant subset of elements of the product, process, computer software, technique, formula, or invention to be held for sale, lease, or license. This shrinking back of the product is to continue until either a subset of elements of the product that satisfies the requirements is reached, or the most basic element of the product is reached and such element fails to satisfy the test.

The Treasury Department and the IRS believe that the proposed rules already apply principles similar to the shrink back rule to allow taxpayers to identify a subset of elements of dual function software that only enables a taxpayer to interact with third parties or allows third parties to initiate functions or review data on the taxpayer's system. The substantially all test referenced by the commenter is similar to the general credit eligibility requirement in section 41(d)(1)(C), which provides that in order for activities to constitute qualified research, substantially all of the activities must constitute elements of a process of experimentation that relates to a qualified purpose. Under § 1.41–4(a)(6), this substantially all requirement is satisfied only if 80 percent or more of a taxpayer's research activities, for the development or improvement of a business component, measured on a cost or other consistently applied reasonable basis, constitute elements of a process of experimentation. In contrast to the general requirement of section 41(d)(1) pertaining to qualifying research, section 41(d)(4)(E) does not apply the substantially all test when it excludes activities related to internal use software from qualifying research. Accordingly, the Treasury Department and the IRS believe the use of the substantially all test in these regulations is inappropriate, and the final regulations do not adopt the commenter's suggested approach.

Another commenter requested that the dual function rules be eliminated because the provisions are confusing and unnecessary and that trying to delineate elements of dual function software raises significant administrative issues. Similarly, another commenter noted that the concepts in the dual function rules can be confusing to taxpayers and will require additional recordkeeping by taxpayers. According to this commenter, most taxpayers do not differentiate their software applications by "third party interactions" or generally track such interactions. One commenter similarly stated that § 1.41–4(c)(6)(iv)(C) of the proposed regulations fails to take into account that software systems cannot always be broken into mutually exclusive subsets enabling only internal use or third party functionality.

Regarding the presumption that dual function software is developed for internal use, a commenter stated that such presumption is contrary to the intent of the statute. One commenter recommended that the presumption should be replaced with a primary purpose test, consistent with the statutory language that looks to whether software is developed "primarily" for internal use.

The Treasury Department and the IRS believe it is necessary to implement rules for dual function software as this type of software development is increasingly common in business practice. Rather than simply reiterating the "primarily" language in the statute, these regulations specifically identify the types of software functions that are considered to be primarily for internal use. A definition that specifically identifies the types of software functions that are considered to be primarily for internal use provides a clearer objective test that will provide consistency in application. The nature of software and its development has rapidly evolved over time, and the statute did not expressly address the treatment of dual function software. In conjunction with crafting a narrow definition of internal use, the Treasury Department and the IRS believe that the dual function software rules in the proposed regulations strike an appropriate balance between the administrative burdens and compliance concerns relating to claiming the research credit for activities relating to software. Thus, these final regulations retain the dual function rules. These final regulations are applicable to taxable years beginning on or after the date of their publication in the **Federal Register**. Taxpayers have been aware of the proposed rules and have had the opportunity to begin maintaining the necessary documentation to establish their entitlement to research credits under these rules.

### *B. Safe Harbor*

The proposed regulations provided taxpayers with a safe harbor to apply to dual function software if there remains a subset of elements of dual function software (dual function subset) after the third party subset has been identified. The safe harbor allows a taxpayer to include 25 percent of the qualified research expenditures of the dual function subset in computing the amount of the taxpayer's credit, provided that the taxpayer's research activities related to the dual function subset constitute qualified research and the use of the dual function subset by third parties or by the taxpayer to interact with third parties is reasonably anticipated to constitute at least 10 percent of the dual function subset's use.

Some commenters requested that the safe harbor be removed from the regulations. Specifically, one commenter stated that the burdens associated with the safe harbor may be greater than its benefits and noted the multiple steps that a taxpayer must take to determine if it meets the safe harbor. Another commenter noted that the safe harbor complicates the administration of the credit for both taxpayers and the IRS.

Another commenter noted that the safe harbor potentially penalizes the taxpayer with the inequitable result of allowing only 25 percent of the qualified research expenditures. According to the commenter, given that a taxpayer must document anticipated use, it should then follow that the portion of software treated as third party facing should mirror this analysis. In other words, the proportion anticipated to be third party facing should be the proportion of software that is not developed primarily for internal use.

After careful consideration, the final regulations do not adopt these comments. However, the safe harbor has been modified to clarify that the safe harbor can be applied to the dual function software or the dual function subset after the application of § 1.41–4(c)(6)(vi)(B) of the final regulations. The safe harbor is not a requirement but an option available for taxpayers who cannot identify a third party subset, or after identification of a third party subset, still have a dual function subset. Without the safe harbor, dual function software or a dual function subset would be presumed to be internal use and the taxpayer would have to demonstrate that the research with respect to the dual function software or dual function subset meets the high threshold of innovation test in addition to the general eligibility requirements under section 41(d)(1). The safe harbor provides a benefit, not a detriment, to taxpayers, provided the dual function software or dual function subset's use by third parties is anticipated to be at least 10 percent of the total use. Taxpayers who consider it too burdensome to comply with the requirements of the safe harbor can choose not to rely upon it.

*C. Time of Determination*

Several commenters noted concerns with the time of determination for the application of the safe harbor. A commenter noted that determining the percentage of third party use based upon an estimate made at the beginning of software development imposes an undue administrative burden and may not be an accurate reflection of the actual use once the software is released. This commenter requested that the rule be eliminated or amended to provide that a taxpayer must estimate third party use once the software is deployed. Similarly, another commenter noted that it has not been their experience that taxpayers plot out the future expected use of their software at the time the development begins with such specificity, especially given that software development is an iterative development process where functionality and expected uses rapidly evolve. Lastly, another commenter requested that, similar to the provisions for improvements to existing software, there should be a mechanism to recharacterize software over time.

While the Treasury Department and the IRS understand commenters' concerns, the final regulations do not change the requirement that the time of determination occur at the beginning of the software development. As discussed herein, the Treasury Department and the IRS continue to believe that the rule requiring that a determination be made at the beginning of the software development is most accurate and appropriate given Congress' intent that the research credit serve as an incentive to conduct qualifying research rather than an unanticipated reward for doing so.

*D. Objective Reasonable Method*

In the proposed regulations, the Treasury Department and the IRS invited comments on the administrability of measuring the reasonably anticipated use of software by taxpayers to interact with third parties and by third parties to initiate functions or review data based on reasonable methods (such as processing time, amount of data transfer, number of software user interface screens, number of third party initiated functions, and other objective, reasonable methods) and whether the regulations should include specific reasonable methods and examples.

A commenter recommended that due to the wide range of taxpayers that will be subject to these regulations, the final regulations should not provide overly detailed examples of "reasonable methods." This commenter noted that it should be clear that any examples of reasonable methods are for illustrative purposes only and any reasonable method may be acceptable. Another commenter recommended the adoption of the phrase "within each industry" to ensure that the application of the objective, reasonable method takes into account unique aspects of all taxpayers within given industries.

The Treasury Department and the IRS agree that it is unrealistic to impose one specific method that will be used to measure reasonably anticipated use due to the variety of industries that are subject to the final regulations. Therefore, the final regulations provide that any objective, reasonable method within the taxpayer's industry may be used for purposes of the safe harbor.

**VI. Third Party Definition**

The proposed regulations provided that the term "third party" means any corporation, trade or business, or other person that is not treated as a single taxpayer with the taxpayer pursuant to section 41(f). A commenter raised concerns and requested that the Treasury Department and the IRS reconsider whether it is appropriate to apply the controlled group standard under section 41(f). The commenter contended that this third party definition would potentially deny a research credit to some software for artificial reasons. The commenter further noted that if the regulations do not modify the third party definition, taxpayers should at least have an opportunity to demonstrate that software provided to a member of the controlled group is not internal use software based on the facts and circumstances.

The Treasury Department and the IRS continue to believe that the use of the controlled group standard under section 41(f) is appropriate. A well established, objective standard is essential and using the standard in section 41(f) is consistent with the reference to section 41(f) in section 41(b)(2) relating to in-house research expenditures and in § 1.41–6(a)(3)(ii) relating to the definition of controlled group for purposes of aggregating expenditures.

The proposed regulations also provided that third parties do not include any persons that use the software to support the taxpayer's general and administrative functions that facilitate or support the conduct of the taxpayer's trade or business, *e.g.*, the taxpayer's own vendors. A commenter contended that excluding any person that uses a taxpayer's software to support a general and administrative function from the definition of third party creates confusion and blurs a well-conceived, objective measurement. This commenter believes the term third party suggests a person who is external to the organization or a person who is not an employee. The Treasury Department and the IRS note that the statute provides a higher standard for internal use software, in part, because the benefits of such software are intended primarily for the taxpayer developing it. Where a taxpayer develops software for internal use, any benefit to others, such as vendors or those who provide support services to the taxpayer, is collateral and secondary. Accordingly, the final regulations do not adopt these comments requesting a change to the definition of third party.

**VII. High Threshold of Innovation—Significant Economic Risk**

The proposed regulations provided that certain internal use software is eligible for the research credit if the software satisfies the high threshold of innovation test, the three parts of which are (1) software is innovative in that the software would result in a reduction in cost or improvement in speed or other measurable improvement, that is substantial and economically significant, if the development is or would have been successful; (2) software development involves significant economic risk in that the taxpayer commits substantial resources to the development and there is a substantial uncertainty, because of technical risk, that such resources would be recovered within a reasonable period; and (3) software is not commercially available for use by the taxpayer in that the software cannot be purchased, leased, or licensed and used for the intended purpose without modifications that would satisfy the innovation and significant economic risk requirements. The proposed regulations further provided that substantial uncertainty exists if, at the beginning of the taxpayer's activities, the information available to the taxpayer does not establish the capability or method for developing or improving the software.

*A. Design Uncertainty*

Several commenters requested that the final regulations include design uncertainty in the definition of technical risk for purposes of meeting the significant economic risk test. Commenters noted that both sections 174 and 41 have long included the concept of design uncertainty. Commenters also raised concerns that the statute and regulations do not define the concepts of capability, methodology, and design uncertainty. Commenters further explained that these three types of uncertainties are inherently related to each other, and it is often difficult for taxpayers to clearly state or describe which type of uncertainty they face.

The use of the word "substantial" before "uncertainty" in the significant economic risk test for internal use software indicates a higher threshold of uncertainty than that required for business components that are not internal use software. While there may be design uncertainty in the development of internal use software, substantial uncertainty generally exists only when there is also uncertainty in regard to the capability or method of achieving the intended result. However, the Treasury Department and the IRS understand that it is difficult to delineate the types of technical uncertainties and attempting to do so may lead to unnecessary burdens on both taxpayers and the IRS. Furthermore, the appropriate design uncertainty of internal use software may be inextricably linked to substantial uncertainty regarding capability or method. The focus of the significant economic risk test should be on the level of uncertainty that exists and not the types of uncertainty. For these reasons, the final regulations remove the reference to capability and method uncertainty. However, the Treasury Department and the IRS believe that internal use software research activities that involve only uncertainty related to appropriate design, and not capability or methodology, would rarely qualify as having substantial uncertainty for purposes of the high threshold of innovation test.

*B. Substantial Resources/Reasonable Time Period*

A commenter requested that the final regulations provide further explanation or examples on what constitutes "substantial resources" or a "reasonable time period" for purposes of meeting the significant economic risk test. The Treasury Department and the IRS believe that whether the amount of resources committed is substantial or whether substantial resources would be recovered within a reasonable time period are factual determinations to be resolved based on the taxpayer's facts and circumstances and, therefore, further explanation or examples would be too specific and not helpful. Accordingly, the final regulations do not adopt these comments.

*C. Application of High Threshold of Innovation Test*

Another commenter requested deletion of the statement, "[i]t is not always necessary to have a revolutionary discovery or creation of new technologies such as a new programming language, operating system, architecture, or algorithm to satisfy the high threshold of innovation test." The commenter is concerned that the sentence can be read to imply that in some situations it will be necessary to have a revolutionary discovery to qualify internal use software for the research credit. The Treasury Department and the IRS did not intend the inclusion of this statement to have the interpretation suggested or taken by the commenter. Accordingly, the Treasury Department and the IRS agree that this statement should be removed from the final regulations because a revolutionary discovery is not required to meet the high threshold of innovation test.

Furthermore, the Treasury Department and the IRS are revising §§ 1.41–4(c)(6)(i) and (ii) of the proposed regulations to clarify that the internal use software rules under § 1.41–4(c)(6) do not apply to (1) software developed for use in an activity that constitutes qualified research, (2) software developed for use in a production process to which the requirements of section 41(d)(1) are met, and (3) a new or improved package of software and hardware developed together by the taxpayer as a single product. Accordingly, under the final regulations, the high threshold of innovation test applies only to the software developed for use in general and administrative functions that facilitate or support the conduct of the taxpayer's trade or business and to dual function software.

**VIII. Examples**

*A. Process of Experimentation*

Section 1.41–4(a)(8) of the proposed regulations provided six new examples illustrating the application of the process of experimentation requirement to software under section 41(d)(1)(C).

One commenter noted that the examples appear to suggest a presumption that activities related to developing web design or ERP software do not meet the process of experimentation requirement. This commenter requested that the final regulations clearly state the reasons for such presumption. The proposed regulations and these final regulations do not establish a presumption against a particular type of software; rather these examples focus on the facts and circumstances surrounding activities to determine whether they involve a process of experimentation.

Another commenter requested that the final regulations include additional examples demonstrating fact patterns that do not initially qualify as a process of experimentation but where a change in facts introduces technical uncertainty that requires a process of experimentation. The final regulations could provide examples describing a particular change in facts that would introduce technical uncertainty and require a process of experimentation; however, because the examples are very factual and would differ based on a taxpayer's business, we do not think more examples would provide the clarification that the commenter is seeking. Accordingly, the final regulations do not include additional examples to address this comment.

i. Example 6

Section 1.41–4(a)(8), Example 6, of the proposed regulations analyzed whether activities related to selecting a commercial software vendor with object-oriented functions and selecting and incorporating the specific functions into new software developed by X involved conducting a process of experimentation.

One commenter noted that the use of certain terms in Example 6, such as "develop," "evaluate," and "determine" suggest that the process of experimentation criteria may be met and recommended changes to clearly show that a purchase, installation, and selection from pre-determined categories do not meet a process of experimentation. We disagree with the commenter because the use or nonuse of certain terms is not an implication that the process of experimentation criteria has or has not been met. This example is intended to show that the process of experimentation requirement is not met regardless of the terms used. Accordingly, the final regulations do not adopt this comment.

ii. Example 7

Section 1.41–4(a)(8), Example 7, of the proposed regulations analyzed whether when developing software, activities relating to X's decision to use a separate server to distribute the workload across each of the web servers and X's decision that a round robin workload distribution algorithm is appropriate for its needs involved conducting a process of experimentation.

Two commenters recommended removing Example 7. One commenter believed that the example did not provide any clarification. The other commenter stated that the example shows a failure to meet the technical uncertainty requirement under section 174, rather than a process of experimentation. While the Treasury Department and the IRS agree with the commenter that activities under section 174 must be for the purpose of discovering information that would eliminate uncertainties, Example 7 is intended to demonstrate the process of experimentation requirement under section 41(d). The example shows a taxpayer's failure to meet the process of experimentation requirement under section 41(d)(1) because the use of a technique or design, such as a round robin workload distribution algorithm, does not qualify where the taxpayer did not conduct a process of evaluating alternatives intended to eliminate uncertainty regarding the development of software. Accordingly, the final regulations do not adopt these comments.

iii. Example 8

Section 1.41–4(a)(8), Example 8, of the proposed regulations analyzed whether X's activities relating to design and systematic testing and evaluation of several different algorithms in the development of load balancing software involved conducting a process of experimentation.

One commenter recommended that all references to the terms "dynamic" and "highly volatile" be removed because the commenter believes the terms provide no additional value and that they suggest that the nature of X's business environment has some bearing on the performance of qualified research. The Treasury Department and the IRS disagree and the final regulations do not adopt the commenter's recommendation because we believe the nature of a taxpayer's business environment can be a valuable indicator of circumstances that may result in the necessary uncertainty required for a process of experimentation.

Another commenter requested that for both Example 8 and Example 10, the Treasury Department and the IRS provide clarification by applying the high threshold of innovation test once the software is determined to be internal use software. Additionally, this commenter requested that the final regulations provide an additional example addressing this process. The Treasury Department and the IRS note that the examples are added to illustrate only the application of a process of experimentation to software research. They are not meant to address the high threshold of innovation test; those examples were provided under § 1.41–4(c)(6)(vi) of the proposed regulations. Furthermore, a comprehensive example that applies the rules contained in § 1.41–4(c)(6) would require more developed facts and layers of analysis and would be better suited for a different type of published guidance than these final regulations. Accordingly, the final regulations do not adopt these comments.

iv. Example 9

Section 1.41–4(a)(8), Example 9, of the proposed regulations analyzed whether X's activities relating to the installation of an ERP system involved a process of experimentation.

Two commenters requested deletion of the phrase "routine programming" in Example 9 because the term is subjective, immeasurable, and inconsistent with *Suder* v. *Commissioner*, T.C. Memo 2014–201. One commenter also stated that taxpayers may confront uncertainty about the appropriate design of the configuration of an ERP system, and the example does not address this technical uncertainty. The Treasury Department and the IRS did not intend to illustrate in this example the types of uncertainty that must be eliminated to satisfy the process of experimentation requirement under section 41(d)(1). Rather, this example demonstrates a taxpayer's failure to meet the process of experimentation requirement under section 41(d)(1) because X did not conduct a process of evaluating alternatives in order to eliminate uncertainty regarding the development of the ERP software. Accordingly, the Treasury Department and the IRS believe further clarification of these examples is unnecessary. Furthermore, the Tax Court's decision in *Suder* is not inconsistent with Example 9 because in *Suder* the court did not address whether "routine programming" could meet the process of experimentation requirement.

*B. Internal Use Software*

The proposed regulations provided examples illustrating the provisions contained in § 1.41–4(c)(6) of the proposed regulations.

i. Example 3

Section 1.41–4(c)(6)(vi), Example 3, of the proposed regulations analyzed whether software that is developed for a Web site that provides general information about the taxpayer's business, and which does not enable a taxpayer to interact with third parties or allow third parties to initiate functions or review data, is internal use software.

One commenter disagreed with the characterization of the facts in Example 3 which illustrates a support services function. The commenter believes that the software is dual function software that is developed to allow a third party to review data and to be used in marketing. The Treasury Department and the IRS disagree with the commenter's characterization of Example 3. The example demonstrates that the software is intended to serve marketing purposes and thus is developed to be used in general and administrative functions. Changes were made to clarify this example which is designated as Example 4 of the final regulations.

ii. Example 6

Section 1.41–4(c)(6)(vi), Example 6, of the proposed regulations analyzed the definition of third parties, specifically whether software that is developed to allow its users to upload and modify photographs at no charge allows third parties to initiate functions on the taxpayer's system.

A commenter believed the example is an important example that comes to the correct conclusion, but the commenter believed it is not a particularly good fact pattern to illustrate the third party interaction exclusion. Specifically, the commenter requested changes to the conclusion of the example to show that the advertising software is developed for use in a marketing function to an unrelated third party.

The purpose of the example is to illustrate the third party definition and to demonstrate whether the software is developed to allow third parties to initiate functions or review data. The example is not meant to address which, if any, general and administrative function applies to the software. Accordingly, the final regulations do not adopt this comment. However, other changes were made to clarify Example 6 of the proposed regulations, which is designated as Example 8 of the final regulations.

### IX. Effective/Applicability Date

Some commenters requested that the final regulations apply retroactively back to 1986, while one commenter requested that the final regulations apply retroactively back to 2004 to give software development equal treatment with all other types of qualified research as defined under TD 9104 (69 FR 22). After further consideration, the effective date in the proposed regulations is generally retained with slight modifications. These final regulations are prospective and apply to taxable years beginning on or after the date of publication of this Treasury decision in the **Federal Register**.

Retroactive application of these final regulations may provide an unfair advantage to taxpayers whose prior taxable years are not closed by the statute of limitations. Furthermore, retroactively determining whether taxpayers engaged in research activities does not further the purpose of section 41 which is to encourage taxpayers to engage in qualifying research activities within the United States and would impose a significant administrative burden on the IRS.

Section 41(d)(4)(E) provides that, except to the extent provided by regulations, research with respect to computer software that is developed by (or for the benefit of) the taxpayer primarily for internal use by the taxpayer is excluded from the definition of qualified research under section 41(d). The nature of software and its development has rapidly evolved over time. Recognizing the evolving nature of software technology and its role in business practices, these final regulations more narrowly define internal use software than the rules that apply for prior periods. These final regulations are not, and should not be viewed as, an interpretation of prior regulatory guidance. Software not developed for internal use under these final regulations, such as software developed to enable a taxpayer to interact with third parties, may or may not have been internal use software under prior law.

The proposed regulations provided that the 2004 ANPRM (published in the **Federal Register** (69 FR 43)) is withdrawn effective for taxable years beginning on or after January 20, 2015, the date the proposed regulations were published in the **Federal Register** (80 FR 2624). For taxable years ending before January 20, 2015, taxpayers may choose to follow either all of the internal use software provisions of § 1.41–4(c)(6) in the final regulations published on January 3, 2001 in the **Federal Register** (TD 8930; 66 FR 280) or all of the internal use software provisions of § 1.41–4(c)(6) contained in the proposed regulations (REG–112991–01) published on December 26, 2001 in the **Federal Register** (66 FR 66362). In addition, the IRS will not challenge return positions consistent with all of paragraph (c)(6) of these final regulations or all of paragraph (c)(6) of the proposed regulations for any taxable year that both ends on or after January 20, 2015, the date the proposed regulations were published in the **Federal Register** (80 FR 2624), and begins before October 4, 2016.

### X. Duty of Consistency

Some commenters noted the administrative difficulties of applying the duty of consistency rule under section 41(c)(6)(A) and requested guidance on how to comply with the consistency rule.

The duty of consistency is a statutory requirement and existing regulations under §§ 1.41–3(d) and 1.41–9(c) provide sufficient guidance for taxpayers to follow. In computing the research credit, qualified research expenses and gross receipts must be determined on a basis consistent with the definition of qualified research expenses and gross receipts for the credit year. These final regulations do not modify this existing law. Section 1.41–3(d) provides that in computing the credit for increasing research activities, qualified research expenses and gross receipts taken into account in computing a taxpayer's fixed-base percentage and a taxpayer's base amount must be determined on a basis consistent with the definition of qualified research expenses and gross receipts for the credit year, without regard to the law in effect for the taxable years taken into account in computing the fixed-base percentage or the base amount. Section 1.41–3(d) also provides examples illustrating the requirement. Current section 1.41–9(c) contains similar rules. Accordingly, the final regulations do not adopt the commenters' suggestions concerning the duty of consistency.

### Special Analyses

Certain IRS regulations, including this one, are exempt from the requirements of Executive Order 12866, as supplemented and reaffirmed by Executive Order 13563. Therefore, a regulatory impact assessment is not required. It also has been determined that section 553(b) of the Administrative Procedure Act (5 U.S.C. chapter 5) does not apply to these regulations, and because the regulations do not impose a collection of information on small entities, the Regulatory Flexibility Act (5 U.S.C. chapter 6) does not apply. Pursuant to section 7805(f) of the Code, the notice of proposed rulemaking was submitted to the Chief Counsel for Advocacy of the Small Business Administration for comment on its impact on small business, and no comments were received.

### Drafting Information

The principal author of these regulations is Martha M. Garcia, Office of the Associate Chief Counsel (Passthroughs and Special Industries), IRS. However, other personnel from the Treasury Department and the IRS participated in their development.

### List of Subjects in 26 CFR Part 1

Income taxes, Reporting and recordkeeping requirements.

### Adoption of Amendments to the Regulations

Accordingly, 26 CFR part 1 is amended as follows:

## PART 1—INCOME TAXES

■ **Paragraph 1.** The authority citation for part 1 is amended by adding an entry in numerical order to read in part as follows:

**Authority:** 26 U.S.C. 7805 * * *

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Section 1.41–4 also issued under 26 U.S.C. 41(d)(4)(E).

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■ **Par. 2.** Section 1.41–0 is amended by:
■ 1. Revising the entry in the table of contents for § 1.41–4(c)(6).
■ 2. Adding entries in the table of contents for § 1.41–4(c)(6)(i) through (viii).

The revision and additions read as follows:

**§ 1.41–0. Table of contents.**

* * * * *

**§ 1.41–4. Qualified research for expenditures paid or incurred in taxable years ending on or after December 31, 2003.**

* * * * *

(c) * * *

(6) Internal use software.
(i) General rule.
(ii) Inapplicability of the high threshold of innovation test.
(iii) Software developed primarily for internal use.
(iv) Software not developed primarily for internal use.
(v) Time and manner of determination.
(vi) Software developed for both internal use and to enable interaction with third parties (dual function software).
(vii) High threshold of innovation test.
(viii) Illustrations.

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■ **Par. 3.** Section 1.41–4 is amended by:
■ 1. Adding *Example 5* through *Example 10* at the end of paragraph (a)(8).
■ 2. Revising paragraphs (c)(6) and (e).

The additions and revisions read as follows:

**§ 1.41–4 Qualified research for expenditures paid or incurred in taxable years ending on or after December 31, 2003.**

(a) * * *

(8) * * *

*Example 5.* (i) *Facts.* X, a retail and distribution company, wants to upgrade its warehouse management software. X evaluates several of the alternative warehouse management software products available from vendors in the marketplace to determine which product will best serve X's technical requirements. X selects vendor V's software.

(ii) *Conclusion.* X's activities to select the software are not qualified research under section 41(d)(1) and paragraph (a)(5) of this section. X did not conduct a process of evaluating alternatives in order to eliminate uncertainty regarding the development of a business component. X's evaluation of products available from vendors is not a process of experimentation.

*Example 6.* (i) *Facts.* X wants to develop a new web application to allow customers to purchase its products online. X, after reviewing commercial software offered by various vendors, purchases a commercial software package of object-oriented functions from vendor Z that X can use in its web application (for example, a shopping cart). X evaluates the various object-oriented functions included in vendor Z's software package to determine which functions it can use. X then incorporates the selected software functions in its new web application software.

(ii) *Conclusion.* X's activities related to selecting the commercial software vendor with the object-oriented functions it wanted, and then selecting which functions to use, are not qualified research under section 41(d)(1) and paragraph (a)(5) of this section. In addition, incorporating the selected object-oriented functions into the new web application software being developed by X did not involve conducting a process of evaluating alternatives in order to eliminate uncertainty regarding the development of software. X's evaluation of products available from vendors and selection of software functions are not a process of experimentation.

*Example 7.* (i) *Facts.* In order to be more responsive to user online requests, X wants to develop software to balance the incoming processing requests across multiple web servers that run the same set of software applications. Without evaluating or testing any alternatives, X decides that a separate server will be used to distribute the workload across each of the web servers and that a round robin workload distribution algorithm is appropriate for its needs.

(ii) *Conclusion.* X's activities to develop the software are activities relating to the development of a separate business component under section 41(d)(2)(A). X's activities to develop the load distribution function are not qualified research under section 41(d)(1) and paragraph (a)(5) of this section. X did not conduct a process of evaluating different load distribution alternatives in order to eliminate uncertainty regarding the development of software. X's selection of a separate server and a round robin distribution algorithm is not a process of experimentation.

*Example 8.* (i) *Facts.* X must develop load balancing software across a server cluster supporting multiple web applications. X's web applications have high concurrency demands because of a dynamic, highly volatile environment. X is uncertain of the appropriate design of the load balancing algorithm, given that the existing evolutionary algorithms did not meet the demands of their highly volatile web environment. Therefore, X designs and systematically tests and evaluates several different algorithms that perform the load distribution functions.

(ii) *Conclusion.* X's activities to develop software are activities to develop a separate business component under section 41(d)(2)(A). X's activities involving the design, evaluation, and systematic testing of several new load balancing algorithms meet the requirements as set forth in paragraph (a)(5) of this section. X's activities constitute elements of a process of experimentation because X identified uncertainties related to the development of a business component, identified alternatives intended to eliminate those uncertainties, and evaluated one or more alternatives to achieve a result where the appropriate design was uncertain at the beginning of X's research activities.

*Example 9.* (i) *Facts.* X, a multinational manufacturer, wants to install an enterprise resource planning (ERP) system that runs off a single database so that X can track orders more easily, and coordinate manufacturing, inventory, and shipping among many different locations at the same time. In order to successfully install and implement ERP software, X evaluates its business needs and the technical requirements of the software, such as processing power, memory, storage, and network resources. X devotes the majority of its resources in implementing the ERP system to evaluating the available templates, reports, and other standard programs and choosing among these alternatives in configuring the system to match its business process and reengineering its business process to match the available alternatives in the ERP system. X also performs some data transfer from its old system, involving routine programming and one-to-one mapping of data to be exchanged between each system.

(ii) *Conclusion.* X's activities related to the ERP software including the data transfer are not qualified research under section 41(d)(1) and paragraph (a)(5) of this section. X did not conduct a process of evaluating alternatives in order to eliminate uncertainty regarding the development of software. X's activities in choosing between available templates, reports, and other standard programs and conducting data transfer are not elements of a process of experimentation.

*Example 10.* (i) *Facts.* Same facts as *Example 9* except that X determines that it must interface part of its legacy software with the new ERP software because the ERP software does not provide a particular function that X requires for its business. As a result, X must develop an interface between its legacy software and the ERP software, and X evaluates several data exchange software applications and chooses one of the available alternatives. X is uncertain as to how to keep the data synchronized between the legacy and ERP systems. Thus, X engages in systematic trial and error testing of several newly designed data caching algorithms to eliminate synchronization problems.

(ii) *Conclusion.* Substantially all of X's activities with respect to this ERP project do not satisfy the requirements for a process of experimentation. However, when the shrinking-back rule is applied, a subset of X's activities do satisfy the requirements for a process of experimentation. X's activities to develop the data caching software and keeping the data on the legacy and ERP systems synchronized meet the requirements of qualified research as set forth in paragraph (a)(2) of this section. Substantially all of X's activities to develop the specialized data caching and synchronization software constitute elements of a process of experimentation because X identified uncertainties related to the development of a business component, identified alternatives intended to eliminate those uncertainties, and evaluated alternatives to achieve a result where the appropriate design of that result was uncertain as of the beginning of the taxpayer's research activities.

* * * * *

(c) * * *

(6) *Internal use software*—(i) *General rule.* Research with respect to software that is developed by (or for the benefit of) the taxpayer primarily for the taxpayer's internal use is eligible for the research credit only if—

(A) The research with respect to the software satisfies the requirements of section 41(d)(1);

(B) The research with respect to the software is not otherwise excluded under section 41(d)(4) (other than section 41(d)(4)(E)); and

(C) The software satisfies the high threshold of innovation test of paragraph (c)(6)(vii) of this section.

(ii) *Inapplicability of the high threshold of innovation test.* This paragraph (c)(6) does not apply to the following:

(A) Software developed by (or for the benefit of) the taxpayer primarily for internal use by the taxpayer for use in an activity that constitutes qualified research (other than the development of the internal use software itself);

(B) Software developed by (or for the benefit of) the taxpayer primarily for internal use by the taxpayer for use in a production process to which the requirements of section 41(d)(1) are met; and

(C) A new or improved package of software and hardware developed together by the taxpayer as a single product (or to the costs to modify an acquired software and hardware package), of which the software is an integral part, that is used directly by the taxpayer in providing services in its trade or business. In these cases, eligibility for the research credit is to be determined by examining the combined hardware-software product as a single product.

(iii) *Software developed primarily for internal use*—(A) *In general.* Except as otherwise provided in paragraph (c)(6)(vi) of this section, software is developed by (or for the benefit of) the taxpayer primarily for the taxpayer's internal use if the software is developed for use in general and administrative functions that facilitate or support the conduct of the taxpayer's trade or business. Software that the taxpayer develops primarily for a related party's internal use will be considered internal use software. A related party is any corporation, trade or business, or other person that is treated as a single taxpayer with the taxpayer pursuant to section 41(f).

(B) *General and administrative functions.* General and administrative functions are:

(*1*) *Financial management.* Financial management functions are functions that involve the financial management of the taxpayer and the supporting recordkeeping. Financial management functions include, but are not limited to, functions such as accounts payable, accounts receivable, inventory management, budgeting, cash management, cost accounting, disbursements, economic analysis and forecasting, financial reporting, finance, fixed asset accounting, general ledger bookkeeping, internal audit, management accounting, risk management, strategic business planning, and tax.

(*2*) *Human resources management.* Human resources management functions are functions that manage the taxpayer's workforce. Human resources management functions include, but are not limited to, functions such as recruiting, hiring, training, assigning personnel, and maintaining personnel records, payroll, and benefits.

(*3*) *Support services.* Support services are other functions that support the day-to-day operations of the taxpayer. Support services include, but are not limited to, functions such as data processing, facility services (for example, grounds keeping, housekeeping, janitorial, and logistics), graphic services, marketing, legal services, government compliance services, printing and publication services, and security services (for example, video surveillance and physical asset protection from fire and theft).

(iv) *Software not developed primarily for internal use.* Software is not developed primarily for the taxpayer's internal use if it is not developed for use in general and administrative functions that facilitate or support the conduct of the taxpayer's trade or business, such as—

(A) Software developed to be commercially sold, leased, licensed, or otherwise marketed to third parties; or

(B) Software developed to enable a taxpayer to interact with third parties or to allow third parties to initiate functions or review data on the taxpayer's system.

(v) *Time and manner of determination.* For purposes of paragraphs (c)(6)(iii) and (iv) of this section, whether software is developed primarily for internal use or not developed primarily for internal use depends on the intent of the taxpayer and the facts and circumstances at the beginning of the software development. For example, software will not be considered internal use software solely because it is used internally for purposes of testing prior to commercial sale, lease, or license. If a taxpayer originally develops software primarily for internal use, but later makes improvements to the software with the intent to hold the improved software to be sold, leased, licensed, or otherwise marketed to third parties, or to interact with third parties or to allow third parties to initiate functions or review data on the taxpayer's system using the improved software, the improvements will be considered separate from the existing software and will not be considered developed primarily for internal use. Alternatively, if a taxpayer originally develops software to be sold, leased, licensed, or otherwise marketed to third parties, or to interact with third parties or to allow third parties to initiate functions or review data on the taxpayer's system, but later makes improvements to the software with the intent to use the software in general and administrative functions, the improvements will be considered separate from the existing software and will be considered developed primarily for internal use.

(vi) *Software developed for both internal use and to enable interaction with third parties (dual function software)*—(A) *Presumption of development primarily for internal use.* Unless paragraph (c)(6)(vi)(B) or (C) of this section applies, software developed by (or for the benefit of) the taxpayer both for use in general and administrative functions that facilitate or support the conduct of the taxpayer's trade or business and to enable a taxpayer to interact with third parties or to allow third parties to initiate functions or review data on the taxpayer's system (dual function software) is presumed to be developed primarily for a taxpayer's internal use.

(B) *Identification of a subset of elements of software that only enables interaction with third parties.* To the extent that a taxpayer can identify a subset of elements of dual function software that only enables a taxpayer to interact with third parties or allows third parties to initiate functions or review data (third party subset), the presumption under paragraph (c)(6)(vi)(A) of this section does not apply to such third party subset, and such third party subset is not developed primarily for internal use as described under paragraph (c)(6)(iv)(B) of this section.

(C) *Safe harbor for expenditures related to software developed for both internal use and to enable interaction with third parties.* If, after the application of paragraph (c)(6)(vi)(B) of this section, there remains dual function software or a subset of elements of dual function software (dual function subset), a taxpayer may include 25 percent of the qualified research expenditures of such dual function software or dual function subset in computing the amount of the taxpayer's credit. This paragraph (c)(6)(vi)(C) applies only if the taxpayer's research activities related to the development or improvement of the dual function software or dual function subset constitute qualified research under section 41(d), without regard to section 41(d)(4)(E), and the dual function software or dual function subset's use by third parties or by the taxpayer to interact with third parties is reasonably anticipated to constitute at least 10 percent of the dual function software or the dual function subset's use. An objective, reasonable method within the taxpayer's industry must be used to estimate the dual function software or dual function subset's use by third parties or by the taxpayer to interact with third parties. An objective, reasonable method may include, but is not limited to, processing time, amount of data transfer, and number of software user interface screens.

(D) *Time and manner of determination.* A taxpayer must apply this paragraph (c)(6)(vi) based on the intent of the taxpayer and the facts and circumstances at the beginning of the software development.

(E) *Third party.* For purposes of paragraphs (c)(6)(iv), (v), and (vi) of this section, the term *third party* means any corporation, trade or business, or other person that is not treated as a single taxpayer with the taxpayer pursuant to section 41(f). Additionally, for purposes of paragraph (c)(6)(iv)(B) of this section, third parties do not include any persons that use the software to support the general and administrative functions of the taxpayer.

(vii) *High threshold of innovation test*—(A) *In general.* Software satisfies this paragraph (c)(6)(vii) only if the taxpayer can establish that—

(*1*) The software is innovative;

(*2*) The software development involves significant economic risk; and

(*3*) The software is not commercially available for use by the taxpayer in that the software cannot be purchased, leased, or licensed and used for the intended purpose without modifications that would satisfy the requirements of paragraphs (c)(6)(vii)(A)(*1*) and (*2*) of this section.

(B) *Innovative.* Software is innovative if the software would result in a reduction in cost or improvement in speed or other measurable improvement, that is substantial and economically significant, if the development is or would have been successful. This is a measurable objective standard, not a determination of the unique or novel nature of the software or the software development process.

(C) *Significant economic risk.* The software development involves significant economic risk if the taxpayer commits substantial resources to the development and if there is substantial uncertainty, because of technical risk, that such resources would be recovered within a reasonable period. The term "substantial uncertainty" requires a higher level of uncertainty and technical risk than that required for business components that are not internal use software. This standard does not require technical uncertainty regarding whether the final result can ever be achieved, but rather whether the final result can be achieved within a timeframe that will allow the substantial resources committed to the development to be recovered within a reasonable period. Technical risk arises from uncertainty that is technological in nature, as defined in paragraph (a)(4) of this section, and substantial uncertainty must exist at the beginning of the taxpayer's activities.

(D) *Application of high threshold of innovation test.* The high threshold of innovation test of paragraph (c)(6)(vii) of this section takes into account only the results anticipated to be attributable to the development of new or improved software at the beginning of the software development independent of the effect of any modifications to related hardware or other software. The implementation of existing technology by itself is not evidence of innovation, but the use of existing technology in new ways could be evidence of a high threshold of innovation if it resolves substantial uncertainty as defined in paragraph (c)(6)(vii)(C) of this section.

(viii) *Illustrations.* The following examples illustrate provisions contained in this paragraph (c)(6). No inference should be drawn from these examples concerning the application of section 41(d)(1) and paragraph (a) of this section to these facts.

*Example 1. Computer hardware and software developed as a single product*—(i) *Facts.* X is a telecommunications company that developed high technology telephone switching hardware. In addition, X developed software that interfaces directly with the hardware to initiate and terminate a call, along with other functions. X designed and developed the hardware and software together.

(ii) *Conclusion.* The telecommunications software that interfaces directly with the hardware is part of a package of software and hardware developed together by the taxpayer that is used by the taxpayer in providing services in its trade or business. Accordingly, this paragraph (c)(6) does not apply to the software that interfaces directly with the hardware as described in paragraph (c)(6)(ii)(C) of this section, and eligibility for the research credit is determined by examining the combined software-hardware product as a single product.

*Example 2. Internal use software; financial management*—(i) *Facts.* X, a manufacturer, self-insures its liabilities for employee health benefits. X develops its own software to administer its self-insurance reserves related to employee health benefits. At the beginning of the development, X does not intend to develop the software for commercial sale, lease, license, or to be otherwise marketed to third parties or to enable X to interact with third parties or to allow third parties to initiate functions or review data on X's system.

(ii) *Conclusion.* The software is developed for use in a general and administrative function because reserve valuation is a financial management function under paragraph (c)(6)(iii)(B)(*1*) of this section. Accordingly, the software is internal use software because it is developed for use in a general and administrative function.

*Example 3. Internal use software; human resources management*—(i) *Facts.* X, a manufacturer, develops a software module that interacts with X's existing payroll software to allow X's employees to print pay stubs and make certain changes related to payroll deductions over the internet. At the beginning of the development, X does not intend to develop the software module for commercial sale, lease, license, or to be otherwise marketed to third parties or to enable X to interact with third parties or to allow third parties to initiate functions or review data on X's system.

(ii) *Conclusion.* The employee access software module is developed for use in a general and administrative function because employee access software is a human resources management function under paragraph (c)(6)(iii)(B)(*2*) of this section. Accordingly, the software module is internal use software because it is developed for use in a general and administrative function.

*Example 4. Internal use software; support services*—(i) *Facts.* X, a restaurant, develops software for a Web site that provides information, such as items served, price, location, phone number, and hours of operation for purposes of advertising. At the beginning of the development, X does not intend to develop the Web site software for commercial sale, lease, license, or to be otherwise marketed to third parties or to enable X to interact with third parties or to allow third parties to initiate functions or review data on X's system. X intends to use the software for marketing by allowing third parties to review general information on X's Web site.

(ii) *Conclusion.* The software is developed for use in a general and administrative function because the software was developed to be used by X for marketing which is a support services function under paragraph (c)(6)(iii)(B)(*3*) of this section. Accordingly, the software is internal use software because it is developed for use in a general and administrative function.

*Example 5. Internal use software*—(i) *Facts.* X, a multinational manufacturer with different business and financial systems in each of its divisions, undertakes a software development project aimed at integrating the majority of the functional areas of its major software systems (Existing Software) into a single enterprise resource management system supporting centralized financial systems, human resources, inventory, and sales. X purchases software (New Software) upon which to base its enterprise-wide system. X has to develop software (Developed Software) that transfers data from

X's legacy financial, human resources, inventory, and sales systems to the New Software. At the beginning of the development, X does not intend to develop the software for commercial sale, lease, license, or to be otherwise marketed to third parties or to enable X to interact with third parties or to allow third parties to initiate functions or review data on X's system.

(ii) *Conclusion.* The financial systems, human resource systems, inventory and sales systems are general and administrative functions under paragraph (c)(6)(iii)(B) of this section. Accordingly, the Developed Software is internal use software because it is developed for use in general and administrative functions.

*Example 6. Internal use software; definition of third party*—(i) *Facts.* X develops software to interact electronically with its vendors to improve X's inventory management. X develops the software to enable X to interact with vendors and to allow vendors to initiate functions or review data on the taxpayer's system. X defines the electronic messages that will be exchanged between X and the vendors. X's software allows a vendor to request X's current inventory of the vendor's product, and allows a vendor to send a message to X which informs X that the vendor has just made a new shipment of the vendor's product to replenish X's inventory. At the beginning of development, X does not intend to develop the software for commercial sale, lease, license, or to be otherwise marketed to third parties.

(ii) *Conclusion.* Under paragraph (c)(6)(vi)(E) of this section, X's vendors are not third parties for purposes of paragraph (c)(6)(iv) of this section. While X's software was developed to allow vendors to initiate functions or review data on the taxpayer's system, the software is not excluded from internal use software as set forth in paragraph (c)(6)(iv)(B) of this section because the software was developed to allow vendors to use the software to support X's inventory management, which is a general and administrative function of X.

*Example 7. Not internal use software; third party interaction*—(i) *Facts.* X, a manufacturer of various products, develops software for a Web site with the intent to allow third parties to access data on X's database, to order X's products and track the status of their orders online. At the beginning of the development, X does not intend to develop the Web site software for commercial sale, lease, license, or to be otherwise marketed to third parties.

(ii) *Conclusion.* The software is not developed primarily for internal use because it is not developed for use in a general and administrative function. X developed the software to allow third parties to initiate functions or review data on the taxpayer's system as provided under paragraph (c)(6)(iv)(B) of this section.

*Example 8. Not internal use software; third party interaction*—(i) *Facts.* X developed software that allows its users to upload and modify photographs at no charge. X earns revenue by selling advertisements that are displayed while users enjoy the software that X offers for free. X also developed software that has interfaces through which advertisers can bid for the best position in placing their ads, set prices for the ads, or develop advertisement campaign budgets. At the beginning of the development, X intended to develop the software to enable X to interact with third parties or to allow third parties to initiate functions on X's system.

(ii) *Conclusion.* The software for uploading and modifying photographs is not developed primarily for internal use because it is not developed for use in X's general and administrative functions under paragraph (c)(6)(iii)(A) of this section. The users and the advertisers are third parties for purposes of paragraph (c)(6)(iv) of this section. Furthermore, both the software for uploading and modifying photographs and the advertising software are not internal use software under paragraph (c)(6)(iv)(B) of this section because at the beginning of the development X developed the software with the intention of enabling X to interact with third parties or to allow third parties to initiate functions on X's system.

*Example 9. Not internal use software; commercially sold, leased, licensed, or otherwise marketed*—(i) *Facts.* X is a provider of cloud-based software. X develops enterprise application software (including customer relationship management, sales automation, and accounting software) to be accessed online and used by X's customers. At the beginning of development, X intended to develop the software for commercial sale, lease, license, or to be otherwise marketed to third parties.

(ii) *Conclusion.* The software is not developed primarily for internal use because it is not developed for use in a general and administrative function. X developed the software to be commercially sold, leased, licensed, or otherwise marketed to third parties under paragraph (c)(6)(iv)(A) of this section.

*Example 10. Improvements to existing internal use software*—(i) *Facts.* X has branches throughout the country and develops its own facilities services software to coordinate moves and to track maintenance requests for all locations. At the beginning of the development, X does not intend to develop the software for commercial sale, lease, license, or to be otherwise marketed to third parties or to enable X to interact with third parties or to allow third parties to initiate functions or review data on X's system. Several years after completing the development and using the software, X consults its business development department, which assesses the market for the software. X determines that the software could be sold at a profit if certain technical and functional enhancements are made. X develops the improvements to the software, and sells the improved software to third parties.

(ii) *Conclusion.* Support services, which include facility services, are general and administrative functions under paragraph (c)(6)(iii)(B) of this section. Accordingly, the original software is developed for use in general and administrative functions and is, therefore, developed primarily for internal use. However, the improvements to the software are not developed primarily for internal use because the improved software was not developed for use in a general and administrative function. X developed the improved software to be commercially sold, leased, licensed, or otherwise marketed to third parties under paragraphs (c)(6)(iv)(A) and (c)(6)(v) of this section.

*Example 11. Dual function software; identification of a third party subset*—(i) *Facts.* X develops software for use in general and administrative functions that facilitate or support the conduct of X's trade or business and to allow third parties to initiate functions. X is able to identify a third party subset. X incurs $50,000 of research expenditures for the software, 50% of which is allocable to the third party subset.

(ii) *Conclusion.* The software developed by X is dual function software. Because X is able to identify a third party subset, the third party subset is not presumed to be internal use software under paragraph (c)(6)(vi)(A) of this section. If X's research activities related to the third party subset constitute qualified research under section 41(d), and the allocable expenditures are qualified research expenditures under section 41(b), $25,000 of the software research expenditures allocable to the third party subset may be included in computing the amount of X's credit, pursuant to paragraph (c)(6)(vi)(B) of this section. If, after the application of paragraph (c)(6)(vi)(B) of this section, there remains a dual function subset, X may determine whether paragraph (c)(6)(vi)(C) of this section applies.

*Example 12. Dual function software; application of the safe harbor*—(i) *Facts.* The facts are the same as in *Example 11,* except that X is unable to identify a third party subset. X uses an objective, reasonable method at the beginning of the software development to determine that the dual function software's use by third parties to initiate functions is reasonably anticipated to constitute 15% of the dual function software's use.

(ii) *Conclusion.* The software developed by X is dual function software. The software is presumed to be developed primarily for internal use under paragraph (c)(6)(vi)(A) of this section. Although X is unable to identify a third party subset, X reasonably anticipates that the dual function software's use by third parties will be at least 10% of the dual function software's use. If X's research activities related to the development or improvement of the dual function software constitute qualified research under section 41(d), without regard to section 41(d)(4)(E), and the allocable expenditures are qualified research expenditures under section 41(b), X may include $12,500 (25% of $50,000) of the software research expenditures of the dual function software in computing the amount of X's credit pursuant to paragraph (c)(6)(vi)(C) of this section.

*Example 13. Dual function software; safe harbor inapplicable*—(i) *Facts.* The facts are the same as in *Example 11,* except X is unable to identify a third party subset. X uses an objective, reasonable method at the beginning of the software development to determine that the dual function software's use by third parties to initiate functions is reasonably anticipated to constitute 5% of the dual function software's use.

(ii) *Conclusion.* The software developed by X is dual function software. The software is presumed to be developed primarily for X's internal use under paragraph (c)(6)(vi)(A) of this section. X is unable to identify a third party subset, and X reasonably anticipates that the dual function software's use by third parties will be less than 10% of the dual function software's use. X may only include the software research expenditures of the dual function software in computing the amount of X's credit if the software satisfies the high threshold of innovation test of paragraph (c)(6)(vii) of this section and X's research activities related to the development or improvement of the dual function software constitute qualified research under section 41(d), without regard to section 41(d)(4)(E), and the allocable expenditures are qualified research expenditures under section 41(b).

*Example 14. Dual function software; identification of a third party subset and the safe harbor*—(i) *Facts.* X develops software for use in general and administrative functions that facilitate or support the conduct of X's trade or business and to allow third parties to initiate functions and review data. X is able to identify a third party subset (Subset A). The remaining dual function subset of the software (Subset B) allows third parties to review data and provides X with data used in its general and administrative functions. X is unable to identify a third party subset of Subset B. X incurs $50,000 of research expenditures for the software, 50% of which is allocable to Subset A and 50% of which is allocable to Subset B. X determines, at the beginning of the software development, that the processing time of the third party use of Subset B is reasonably anticipated to account for 15% of the total processing time of Subset B.

(ii) *Conclusion.* The software developed by X is dual function software. Because X is able to identify a third party subset, such third party subset (Subset A) is not presumed to be internal use software under paragraph (c)(6)(vi)(A) of this section. If X's research activities related to the development or improvement of Subset A constitute qualified research under section 41(d), and the allocable expenditures are qualified research expenditures under section 41(b), the $25,000 of the software research expenditures allocable to Subset A may be included in computing the amount of X's credit pursuant to paragraph (c)(6)(vi)(B) of this section. Although X is unable to identify a third party subset of Subset B, 15% of Subset B's use is reasonably anticipated to be attributable to the use of Subset B by third parties. If X's research activities related to the development or improvement of Subset B constitute qualified research under section 41(d), without regard to section 41(d)(4)(E), and the allocable expenditures are qualified research expenditures under 41(b), X may include $6,250 (25% x $25,000) of the software research expenditures of Subset B in computing the amount of X's credit, pursuant to paragraph (c)(6)(vi)(C) of this section.

*Example 15. Internal use software; application of the high threshold of innovation test*—(i) *Facts.* X maintained separate software applications for tracking a variety of human resource (HR) functions, including employee reviews, salary information, location within the hierarchy and physical location of employees, 401(k) plans, and insurance coverage information. X determined that improved HR efficiency could be achieved by redesigning its disparate software applications into one employee-centric system, and worked to develop that system. X also determined that commercially available database management systems did not meet all of the requirements of the proposed system. Rather than waiting several years for vendor offerings to mature and become viable for its purpose, X embarked upon the project utilizing older technology that was severely challenged with respect to data modeling capabilities. The improvements, if successful, would provide a reduction in cost and improvement in speed that is substantial and economically significant. For example, having one employee-centric system would remove the duplicative time and cost of manually entering basic employee information separately in each application because the information would only have to be entered once to be available across all applications. The limitations of the technology X was attempting to utilize required that X attempt to develop a new database architecture. X committed substantial resources to the project, but could not predict, because of technical risk, whether it could develop the database software in the timeframe necessary so that X could recover its resources in a reasonable period. Specifically, X was uncertain regarding the capability of developing, within a reasonable period, a new database architecture using the old technology that would resolve its technological issues regarding the data modeling capabilities and the integration of the disparate systems into one system. At the beginning of the development, X did not intend to develop the software for commercial sale, lease, license, or to be otherwise marketed to third parties or to enable X to interact with third parties or to allow third parties to initiate functions or review data on X's system.

(ii) *Conclusion.* The software is internal use software because it is developed for use in a general and administrative function. However, the software satisfies the high threshold of innovation test set forth in paragraph (c)(6)(vii) of this section. The software was intended to be innovative in that it would provide a reduction in cost or improvement in speed that is substantial and economically significant. In addition, X's development activities involved significant economic risk in that X committed substantial resources to the development and there was substantial uncertainty, because of technical risk, that the resources would be recovered within a reasonable period. Finally, at the time X undertook the development of the system, software meeting X's requirements was not commercially available for use by X.

*Example 16. Internal use software; application of the high threshold of innovation test*—(i) *Facts.* X undertook a software project to rewrite a legacy mainframe application using an object-oriented programming language, and to move the new application off the mainframe to a client/server environment. Both the object-oriented language and client/server technologies were new to X. This project was undertaken to develop a more maintainable application, which X expected would significantly reduce the cost of maintenance, and implement new features more quickly, which X expected would provide both significant improvements in speed and reduction in cost. Thus, the improvements, if successful, would provide a reduction in cost and improvement in speed that is substantial and economically significant. X also determined that commercially available systems did not meet the requirements of the proposed system. X was certain that it would be able to overcome any technological uncertainties and implement the improvements within a reasonable period. However, X was unsure of the appropriate methodology to achieve the improvements. At the beginning of the development, X does not intend to develop the software for commercial sale, lease, license, or to be otherwise marketed to third parties or to enable X to interact with third parties or to allow third parties to initiate functions or review data on X's system.

(ii) *Conclusion.* The software is internal use software because it is developed for use in a general and administrative function. X's activities do not satisfy the high threshold of innovation test of paragraph (c)(6)(vii) of this section. Although the software meets the requirements of paragraphs (c)(6)(vii)(A)(*1*) and (*3*) of this section, X's development activities did not involve significant economic risk under paragraph (c)(6)(vii)(A)(*2*) of this section. X did not have substantial uncertainty, because of technical risk, that the resources committed to the project would be recovered within a reasonable period.

*Example 17. Internal use software; application of the high threshold of innovation test*—(i) *Facts.* X wants to expand its internal computing power, and is aware that its PCs and workstations are idle at night, on the weekends, and for a significant part of any business day. Because the general and administrative computations that X needs to make could be done on workstations as well as PCs, X develops a screen-saver-like application that runs on employee computers. When employees' computers have been idle for an amount of time set by each employee, X's application goes back to a central server to get a new job to execute. This job will execute on the idle employee's computer until it has either finished, or the employee resumes working on his computer. The ability to use the idle employee's computers would save X significant costs because X would not have to buy new hardware to expand the computing power. The improvements, if successful, would provide a reduction in cost that is substantial and economically significant. At the time X undertook the software development project, there was no commercial application available with such a capability. In addition, at the time X undertook the software development project, X was uncertain regarding the capability of developing a server application that could schedule and distribute the jobs across thousands of PCs and workstations, as well as handle all the error conditions that occur on a user's machine. X commits substantial resources to the project. X undertakes a process of experimentation to attempt to eliminate its uncertainty. At the beginning of the development, X does not intend to develop the software for commercial sale, lease, license, or to be otherwise marketed to third parties or to enable X to interact with third parties or to allow third parties to initiate functions or review data on X's system.

(ii) *Conclusion.* The software is internal use software because it is developed for use in a general and administrative function. However, the software satisfies the high threshold of innovation test as set forth in paragraph (c)(6)(vii) of this section. The software was intended to be innovative because it would provide a reduction in cost or improvement in speed that is substantial and economically significant. In addition, X's development activities involved significant economic risk in that X committed substantial resources to the development and there was substantial uncertainty that because of technical risk, such resources would be recovered within a reasonable period. Finally, at the time X undertook the development of the system, software meeting X's requirements was not commercially available for use by X.

*Example 18. Internal use software; application of the high threshold of innovation test*—(i) *Facts.* X, a multinational manufacturer, wants to install an enterprise resource planning (ERP) system that runs off a single database. However, to implement the ERP system, X determines that it must integrate part of its old system with the new because the ERP system does not have a particular function that X requires for its business. The two systems are general and administrative software systems. The systems have mutual incompatibilities. The integration, if successful, would provide a reduction in cost and improvement in speed that is substantial and economically significant. At the time X undertook this project, there was no commercial application available with such a capability. X is uncertain regarding the appropriate design of the interface software. However, X knows that given a reasonable period of time to experiment with various designs, X would be able to determine the appropriate design necessary to meet X's technical requirements and would recover the substantial resources that X commits to the development of the system within a reasonable period. At the beginning of the development, X does not intend to develop the software for commercial sale, lease, license, or to be otherwise marketed to third parties or to enable X to interact with third parties or to allow third parties to initiate functions or review data on X's system.

(ii) *Conclusion.* The software is internal use software because it is developed for use in a general and administrative function. X's activities do not satisfy the high threshold of innovation test of paragraph (c)(6)(vii) of this section. Although the software meets the requirements of paragraphs (c)(6)(vii)(A)(*1*) and (*3*) of this section, X's development activities did not involve significant economic risk under paragraph (c)(6)(vii)(A)(*2*) of this section. X did not have substantial uncertainty, because of technical risk, that the resources committed to the project would be recovered within a reasonable period.

* * * * *

(e) *Effective/applicability dates.* Other than paragraph (c)(6) of this section, this section is applicable for taxable years ending on or after December 31, 2003. Paragraph (c)(6) of this section is applicable for taxable years beginning on or after October 4, 2016. For any taxable year that both ends on or after January 20, 2015 and begins before October 4, 2016, the IRS will not challenge return positions consistent with all of paragraph (c)(6) of this section or all of paragraph (c)(6) of this section as contained in the Internal Revenue Bulletin (IRB) 2015–5 (see *www.irs.gov/pub/irs-irbs/irb15-05.pdf*). For taxable years ending before January 20, 2015, taxpayers may choose to follow either all of § 1.41–4(c)(6) as contained in 26 CFR part 1 (revised as of April 1, 2003) and IRB 2001–5 (see *www.irs.gov/pub/irs-irbs/irb01-05.pdf*) or all of § 1.41–4(c)(6) as contained in IRB 2002–4 (see *www.irs.gov/pub/irs-irbs/irb02-04.pdf*).

**John Dalrymple,**

*Deputy Commissioner for Services and Enforcement.*

Approved: August 22, 2016.

**Mark J. Mazur**

*Assistant Secretary of the Treasury (Tax Policy).*

[FR Doc. 2016–23174 Filed 10–3–16; 8:45 am]

BILLING CODE 4830–01–P

## DEPARTMENT OF DEFENSE

### Office of the Secretary

### 32 CFR Part 236

**[DOD–2014–OS–0097/RIN 0790–AJ29]**

### Department of Defense (DoD)'s Defense Industrial Base (DIB) Cybersecurity (CS) Activities

**AGENCY:** Office of the DoD Chief Information Officer, DoD.

**ACTION:** Final rule.

**SUMMARY:** This final rule responds to public comments and updates DoD's Defense Industrial Base (DIB) Cybersecurity (CS) Activities. This rule implements mandatory cyber incident reporting requirements for DoD contractors and subcontractors who have agreements with DoD. In addition, the rule modifies eligibility criteria to permit greater participation in the voluntary DIB CS information sharing program.

**DATES:** *Effective Date:* This rule is effective on November 3, 2016.

**FOR FURTHER INFORMATION CONTACT:** Vicki Michetti, DoD's DIB Cybersecurity Program Office: (703) 604–3167, toll free (855) 363–4227, or *OSD.DIBCSIA@mail.mil.*

**SUPPLEMENTARY INFORMATION:**

*Purpose:* This final rule responds to public comments to the interim final rule published on October 2, 2015. This rule implements statutory requirements for DoD contractors and subcontractors to report cyber incidents that result in an actual or potentially adverse effect on a covered contractor information system or covered defense information residing therein, or on a contractor's ability to provide operationally critical support. The mandatory reporting applies to all forms of agreements between DoD and DIB companies (contracts, grants, cooperative agreements, other transaction agreements, technology investment agreements, and any other type of legal instrument or agreement). The revisions provided are part of DoD's efforts to establish a single reporting mechanism for such cyber incidents on unclassified DoD contractor networks or information systems. Reporting under this rule does not abrogate the contractor's responsibility for any other applicable cyber incident reporting requirement. Cyber incident reporting involving classified information on classified contractor systems will be in accordance with the National Industrial Security Program Operating Manual (DoD–M 5220.22 (*http://dtic.mil/whs/directives/corres/pdf/522022M.pdf*)).

The rule also addresses the voluntary DIB CS information sharing program that is outside the scope of the mandatory reporting requirements. By modifying the eligibility criteria for the DIB CS program, the rule enables greater participation in the voluntary program. Expanding participation in the DIB CS program is part of DoD's comprehensive approach to counter cyber threats through information sharing between the Government and DIB participants.

*Benefits:* The DIB CS program allows eligible DIB participants to receive Government furnished information and cyber threat information from other DIB participants, thereby providing greater insights into adversarial activity targeting the DIB. The program builds trust between DoD and DIB and provides a collaborative environment for participating companies and DoD to share actionable unclassified cyber threat information that may be used to

**BEFORE THE PUBLIC UTILITY COMMISSION**

**OF OREGON**

**UE 335**

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

**EXHIBIT NO. AWEC/205**

**RESPONSES TO DATA REQUESTS**

March 16, 2018

TO: Mark Brown
Public Utility Commission of Oregon

FROM: Stefan Brown
Manager, Regulatory Affairs

**PORTLAND GENERAL ELECTRIC**
**UE 335**
**PGE Response to ICNU Data Request No. 001**
**March 2, 2018**

**Request:**

**Reference the workpaper titled "Exhibit Support 2019_Tax Plan," Tab "Rate Base Data":**

**a. Please provide workpapers supporting the calculation of accumulated deferred taxes identified in Cell "B13" in the amount of $679,803,676;**

**b. Please provide a schedule itemizing the $10,223,834,826 Gross Utility Plant in Service amount identified in Cell "B7" as of December 31, 2018 by FERC account and sub-account; and**

**c. Please provide workpapers supporting the calculation of Depreciation Reserves in the amount of $4,762,772,580 in Cell "B9"**

*Response:*

a. Detail for this number is provided in the file: 2019 Deferred Tax Detail.xls, which is found in the "Unbundling" folder of work papers supporting PGE Exhibit 200. Specifically, see rows 147 and 153 in column E of the "Summary Ms and ADIT" tab. There are no additional work papers for this amount because it represents the year-end 2018 rate base balance of accumulated deferred income taxes (ADIT), and is the result of decades of deferred income tax activity. Although the annual activity for each category of ADIT is calculated within PGE's Tax Provision and PowerPlan systems, the details of that calculation are provided in PGE's response to ICNU Data Request No. 010, part C.

b. Attachment 001-A provides PGE's Gross Utility Plant in Service as of December 31, 2018 by FERC account. There are no sub-accounts below the 300 level.

c. Attachment 001-B provides PGE's Depreciation Reserves as of December 31, 2018. The reserve reflects the portion of PGE's cost of Electric Plant in Service that has been recovered over the accounting periods that asset costs have been classified as in service. The attachment demonstrates the types of activities that occur annually that are classified to the reserve including depreciation expense, retirements, cost of removal and salvage.

March 16, 2018

TO: Mark Brown
Public Utility Commission of Oregon

FROM: Stefan Brown
Manager, Regulatory Affairs

**PORTLAND GENERAL ELECTRIC**
**UE 335**
**PGE Response to ICNU Data Request No. 002**
**March 2, 2018**

**<u>Request:</u>**

**Reference the workpaper titled "Exhibit Support 2019_Tax Plan," Tab "Ex 208 Rate Base Delta," Cell "E11":**

- **a. Please provide workpapers used to calculate the pro forma increase to depreciation reserves in the amount of $33,840,507;**
- **b. Please explain why the depreciation reserves increased by only $33,840,507 in the referenced exhibit, in contrast to annual depreciation expenses of $305,531,327 identified in Exhibit 203; and**
- **c. Does the $33,840,507 amount include incremental depreciation reserves associated with all utility plant in service, or just the incremental depreciation reserves associated only with new plant additions?**

*<u>Response:</u>*

PGE discovered an error in its forecasted year-end 2018 depreciation reserve balance as used in this filing (UE 335). In the file "Exhibit Support 2019_Tax Plan.xls", Tab "Ex 208 Rate Base Delta", Cell "E11", the forecast for the depreciation reserve should have been approximately $19.8 million higher to show a total increase of $53.7 million (i.e., from $4,727,981,385 to $4,781,655,077). Attachment 002-A outlines the required adjustments that should have occurred (see Cell D55).

In determining the forecasted reserve balance for ratemaking purposes, PGE makes certain adjustments to the recorded balance on its general ledger. These adjustments are outlined below.

<u>Cost of removal (COR)</u>
Cost of removal that is collected through depreciation expense is reclassified from the depreciation reserve to a regulatory liability. The balance of the regulatory liability is added

back to the reserve balance which reduces net plant. There is no adjustment to depreciation expense.

Asset Retirement Obligations (ARO)

PGE recognizes AROs for legal obligations related to dismantlement and restoration costs associated with the future retirement of tangible long-lived assets. Upon initial recognition of AROs that are measurable, the probability-weighted future cash flows for the associated retirement costs, discounted using a credit-adjusted risk-free rate, are recognized as both a liability and as an increase in the capitalized carrying amount of the related long-live assets.

Capitalized asset retirement costs (ARC) related to electric utility plant are depreciated over the estimated life of the related asset. The carrying amount of the ARO liability increases over time (accretion) with a corresponding accretion expense recorded.

PGE excludes the balance of the ARC asset and ARC depreciation reserve from net utility plant for ratemaking purposes. The difference between the timing of the recognition of ARC depreciation and accretion expense and the amount included in customers' prices (cost of removal noted above) is recorded as a regulatory asset or liability.

In UE 335, PGE properly reduced utility plant for the balance of the ARC asset. However, adjustments were not made to the reserve for the ARC depreciation balance and the regulatory liability. The sum of these two adjustments equate to a $19,833,183 increase to the depreciation reserve as initially filed in this proceeding.

In Docket No. UE 319 (UE 319), net plant was properly decreased by the regulatory liability related to COR, but included the ARO liability balance instead of the net ARC asset and ARC depreciation balance. The result was an inadvertent understatement of net plant by $49,713,400. Attachment 002-A shows these adjustments.

Although the rate base amounts were incorrect as noted above, the depreciation expense amounts were filed correctly in both UE 319 and UE 335.

March 16, 2018

TO: Mark Brown
Public Utility Commission of Oregon

FROM: Stefan Brown
Manager, Regulatory Affairs

**PORTLAND GENERAL ELECTRIC**
**UE 335**
**PGE Response to ICNU Data Request No. 010**
**March 2, 2018**

**Request:**

**Reference the workpaper titled "2019 Deferred Tax Detail," Tab "Summary Ms and ADIT":**

- a. **Please provide workpapers supporting the value of $789,301,167 in Cell "E68" related to temporary book tax difference;**
- b. **Please provide workpapers supporting the hard-coded production tax credit carryforward values identified in Cells "C7:E10";**
- c. **Please provide an explanation and workpapers supporting the adjustment titled "2010003 7000000875 Stock Incentive Plan RMGMT" in the amount of $3,502,315 on Row 97;**
- d. **Please provide an explanation and workpapers supporting the adjustment titled "2540003 3000000184 Boardman Severance" in the amount of $2,774,773 on Row 128;**
- e. **Please provide an explanation and workpapers supporting the adjustment titled "2320052 7000000255 Healty Hab & Green Source Dev" in the amount of $1,879,007 on Row 120;**
- f. **Please provide an explanation and workpapers supporting the adjustment titled "2320052 7000000254 Clean Wind Development Fund" in the amount of $1,946,757 on Row 119;**
- g. **Please provide an explanation and workpapers supporting the adjustment titled "2320031 A/P Accrued Incentives" in the amount of $7,128,796 on Row 115;**
- h. **Does the Company consider accrued incents a source of cash in its lead lag study?;**
- i. **Please provide an explanation and workpapers supporting the adjustment titled "2320012 A/P – Vacation" in the amount of $4,842,278 on Row 111;**

j. **Does the Company consider accrued vacation a source of cash in its lead lag study?;**
k. **Please provide an explanation and workpapers supporting the adjustment titled "2290001 7000010758 Customer Storm Collection" in the amount of $715,000 on Row 110;**
l. **Please provide an explanation and workpapers supporting the adjustment titled "2320033 A/P - Involuntary Severance" in the amount of $426,107 on Row 116**

*Response:*

PGE's work paper "2019 Deferred Tax Detail.xls" inadvertently contains misaligned numbers in the "Summary Ms and ADIT" tab under column G, rows 72 through 142. The misalignment, however, did not affect any PGE testimony, exhibits, other work papers, or 2019 test year revenue requirement. Attachment 010-A provides the corrected work paper, for use in the calculations described in parts c-g, i, and k-l, below.

a. There are no work papers that support the value in Cell E68 of the work paper titled "2019 Deferred Tax Detail," Tab "Summary Ms and ADIT." The source for this number is a combination of two reports from PGE's PowerTax software. PowerTax is the system utilized to calculate and track property-related deferred taxes. Attached in Attachment 010-B is an Excel workbook with three tabs. The first tab summarizes the key information from the other two tabs. The second and third tabs are extracted reports from PowerTax. The second tab provides the deferred tax balance for all utility property. The third tab contains the deferred tax balance related to the Carty Increment that PGE removed from rate base.

b. The source for the hard-coded production tax credit carryforward values identified in Cells C7:E1O are detailed below.
   1) Cell C10 is the value reported in the 2016 Results of Operations report.
   2) Cell D7 is calculated in the attached work paper identified as Attachment 010-C (see cell O28).
   3) Cell D8 adjusts the 12/31/2016 balance to the balance after the 2016 tax return so that the balance at 12/31/2017 will be supported by the other activity reported in 2017.
   4) Cell D9 is the estimated utilization of PTCs recorded for the year ended 12/31/2017. It is supported by the attached report extracted from the Tax Provision system. The report is identified as Attachment 010-D (see cell B34).
   5) Cell D10 is supported by the attached report extracted from the Tax Provision system and ties to the 2017 Form 10K filed with the SEC. The report is identified as Attachment 010-E (see cell O16).
   6) Cell E7 is calculated on the attached work paper identified as Attachment 010-F (see cell O28).

7) Cell E9 is the estimated utilization of PTCs during 2018. It is supported by the attached report extracted from the Tax Provision system. The report is identified as Attachment 010-G (see cell B29).
8) Cell E10 is supported by the attached report extracted from the Tax Provision system. The report is identified as Attachment 010-H (see Cell L13).

Attachments 010-B, 010-C, 010-D, 010-E, 010-F, 010-G, and 010-H are protected and subject to Protective Order No. 18-047.

c. The referenced item is not an adjustment, but rather an accumulated deferred income tax (ADIT) asset based on the different book/tax treatment of PGE's stock incentive costs when calculating income taxes. There are no specific work papers for this balance because the amount is developed and updated by PGE's Tax Provision and PowerTax systems. The year-end balances in columns D and E, however, can be calculated based on the beginning balances, listed in Columns C, and the Schedule M activity listed in columns G and H. For Column E the 2018 balance is calculated as follows:

   *2018 ADIT balance, column E equals:*
   (2017 ADIT balance) + (2018 Schedule M activity * Current blended statutory tax rate); or

   (Column D) + (Column H * 27.5%)

   *Row 97, column E:*
   $3,502,315 = $3,502,315 + (0 * 27.5%)

   For column D, the calculation is the same as above, but also includes the revaluation of the 2016 ADIT balance based on the federal tax legislation enacted on December 22, 2017.

   *2017 ADIT balance, column D equals:*
   ((2016 ADIT balance / Prior blended statutory tax rate) * Current blended statutory tax rate) + (2017 Schedule M activity * Current blended statutory tax rate); or

   ((Column C / 40%) * 27.5%) + (Column G * 27.5%)

   *Row 97, column D:*
   $3,502,315 = (($5,029,341 / 40%) * 27.5%) + ($162,668 * 27.5%)

d. The referenced item is not an adjustment, but rather an ADIT asset based on the different book/tax treatment of PGE's Boardman severance costs when calculating income taxes. For all other aspects of this response, see PGE's response to part c, above.

e. The referenced item is not an adjustment, but rather an ADIT asset based on the different book/tax treatment of PGE's renewable portfolio costs when calculating income taxes. For all other aspects of this response, see PGE's response to part c, above.

f. The referenced item is not an adjustment, but rather an ADIT asset based on the different book/tax treatment of PGE's Renewable Fixed Option revenues (Schedules 7 and 32) when calculating income taxes. For all other aspects of this response, see PGE's response to part c, above.

g. The referenced item is not an adjustment, but rather an ADIT asset based on the different book/tax treatment of PGE's incentive costs when calculating income taxes. For all other aspects of this response, see PGE's response to part c, above.

h. PGE included accrued incentives in the Expense Lag component of the Lead-Lag study provided in work papers to PGE Exhibit 200. Accrued incentives are also a component of book expenses that are included when calculating taxable income, income tax expense, and deferred taxes. Ultimately, row 115 of the referenced work paper refers to an ADIT asset and not accrued incentives themselves. This tax effect is also part of the timing of tax payments that is included in the Lead-Lag study.

i. The referenced item is not an adjustment, but rather an ADIT asset based on the different book/tax treatment of PGE's payroll vacation costs when calculating income taxes. For all other aspects of this response, see PGE's response to part c, above.

j. PGE did not include accrued vacation in the Lead-Lag study provided in work papers to PGE Exhibit 200. Accrued vacation, however, is a component of book expenses that is included when calculating taxable income, income tax expense, and deferred taxes. Ultimately, row 111 of the referenced work paper refers to an ADIT asset and not accrued vacation itself. Consequently, the timing of tax payments, which is included in the Lead-Lag study, reflects the impact of this item.

k. The referenced item is not an adjustment, but rather an ADIT asset based on the different book/tax treatment of PGE's storm reserve costs when calculating income taxes. For all other aspects of this response, see PGE's response to part c, above.

l. The referenced item is not an adjustment, but rather an ADIT asset based on the different book/tax treatment of PGE's involuntary severance expenses (that are accrued and paid upon employee termination) when calculating income taxes. For all other aspects of this response, see PGE's response to part c, above.

April 18, 2018

TO: Tyler Pepple
Davison Van Cleve, P.C.

FROM: Stefan Brown
Manager, Regulatory Affairs

**PORTLAND GENERAL ELECTRIC**
**UE 335**
**PGE Response to AWEC Data Request No. 017**
**April 4, 2018**

**Request:**

**Please provide workpapers supporting the calculation of Excess Tax Reserves (i.e. Excess Deferred Federal Income Taxes) as defined in§ 13001(d) of the TCJA. Please also include workpapers supporting the amortization of the Excess Tax Reserve balance to net operating income. If the average rate assumption method was used please provide the amortization calculation by FERC account and property vintage.**

*Response:*

Attachment 017-A provides calculation of the estimated Excess Tax Reserve as a result of the TCJA. The re-measurement of 2017 utility deferred taxes is $304 million, which includes the re-measurement of unprotected deferred taxes of ($17 million), protected deferred taxes of $233 million, and re-measurement of the gross-up of $88 million. These amounts are still considered estimated until PGE files its 2017 tax return on or before the extended due date of October 15, 2018.

The average rate assumption method was used to calculate the amortization of the Excess Tax Reserve. The actual amortization is calculated using both the PowerTax and Tax Provision modules and is reported in the Tax Provision module. The estimated calculation of the ARAM amortization for 2018 is in the Tax Provision report located in Attachment 017-B. The amortization by FERC account and property vintage is not available on a work paper. It is imbedded in thousands of system calculations. Attachment 017-B is protected information and subject to Protective Order No. 18-047.

April 18, 2018

TO: Tyler Pepple
Davison Van Cleve, P.C.

FROM: Stefan Brown
Manager, Regulatory Affairs

**PORTLAND GENERAL ELECTRIC**
**UE 335**
**PGE Response to AWEC Data Request No. 026**
**April 4, 2018**

**Request:**

**Please provide forecast transfers to plant by project and by month over the period 1/1/2018 to 12/31/2018.**

*Response:*

Attachment 026-A provides the requested information.

Attachment 026-A is protected and subject to Protective Order No. 18-047.

April 26, 2018

TO: Tyler Pepple
Davison Van Cleve, P.C.

FROM: Stefan Brown
Manager, Regulatory Affairs

**PORTLAND GENERAL ELECTRIC**
**UE 335**
**PGE Response to AWEC Data Request No. 039**
**April 12, 2018**

**Request:**

**Reference PGE/1300 at 33:12-14 where PGE states that "PGE's resources are system resources. Any energy storage facility on the system controlled by PGE provides integrating renewable energy resources as a primary system benefit." Based on this statement, please explain whether:**

**a) Port Westward 2 "provides integrating renewable energy resources as a primary system benefit" and if not, why not?**
**b) Port Westward 1 "provides integrating renewable energy resources as a primary system benefit" and if not, why not?**
**c) Carty "provides integrating renewable energy resources as a primary system benefit" and if not, why not?**
**d) Beaver "provides integrating renewable energy resources as a primary system benefit" and if not, why not?**
**e) Coyote Springs "provides integrating renewable energy resources as a primary system benefit" and if not, why not?**
**f) PGE's hydroelectric resources "provides integrating renewable energy resources as a primary system benefit" and if not, why not?**

*Response:*

PGE objects to this request on the basis that it is vague and irrelevant. The section referenced in PGE Exhibit 1300 pertains to energy storage facilities. This data request is asking about PGE’s generating facilities. Without waiving its objection, PGE responds as follows:

PGE’s resources represent a diverse combination of power supply options used to reliably and economically balance supply and demand. PGE considers load balancing to be a primary system benefit of its resource portfolio as a whole, which includes the generating facilities identified above. Integrating variable energy resources is one component of balancing load. Depending on the specific capabilities of each resource and the system's requirements (e.g., energy, flexibility, peaking capacity, reserves, etc.) during any given period, each resource is capable of contributing, either partially or fully, to integrating variable energy resources as a "primary system benefit." For example, flexible resources, such as some of PGE's hydroelectric resources and gas facilities, are capable of responding to quicker, more frequent changes in variable energy resource output. Some of PGE's larger gas facilities are capable of providing energy and ramping when variable energy resources are not consistently producing or are experiencing gradual deviations in output. As previously mentioned, the task of variable energy resource integration is accomplished using a portfolio of resources that can serve several functions depending on system conditions.

May 1, 2018

TO: Tyler Pepple
Davison Van Cleve, P.C.

FROM: Stefan Brown
Manager, Regulatory Affairs

**PORTLAND GENERAL ELECTRIC**
**UE 335**
**PGE Response to AWEC Data Request No. 045**
**Dated April 4, 2018**

**Reference Exhibit Support 2019 _Tax Plan, Tab "Sch Ms+ Tax CRs":**

a. **Please provide workpapers to support the calculation of the $7,011,795 associated with Excess Deferred Federal Income Taxes.**
b. **Please reconcile the $7,011,795 amount with the amount reported in "UE 335 AWEC DR 017 Attach B -CONF.xlsx."**
c. **Please explain PGE's proposal for Excess Deferred Federal Income Taxes associated with unprotected book-tax differences for Schedule M Items other than depreciation.**

_Response:_

a. The report from the Tax Provision system that supports the $7,011,795 associated with Excess-Deferred Federal Income taxes is included as Attachment 045-A.

   Attachment 045-A is protected information and subject to Protective Order No. 18-047.

b. The difference between the $7 million in the referenced report and the amount reported in “UE 335_AWEC DR 017_Attach B_CONF” is an update to a more current 2018 forecast that was filed as a part of PGE’s tax deferral filing (Docket No. UM 1920) on April 13, 2018.

c. PGE has filed a request to defer, for later rate making treatment, the expected net benefits associated with the tax rules and provisions implemented through the tax legislation enacted on December 22, 2017. The calculation of the net benefit includes the net excess accumulated deferred income tax that is “unprotected” and not subject to IRS normalization rules and was amortized at year-end 2017, in accordance with GAAP.

May 1, 2018

TO: Tyler Pepple
Davison Van Cleve, P.C.

FROM: Stefan Brown
Manager, Regulatory Affairs

**PORTLAND GENERAL ELECTRIC**
**UE 335**
**PGE Response to AWEC Data Request No. 046**
**Dated April 4, 2018**

**Reference "UE 335 AWEC DR 017 Attach B CONF.xlsx":**

- **a. Please provide this workpaper with formulas and links intact.**
- **b. Please provide a description for each line in the referenced attachment.**
- **c. If PGE does not have the vintage data available, please provide PGE's calculation of EDFIT and ADIT as of 12/31/2017 by FERC Account.**
- **d. When calculating the ARAM amounts for plant ADIT balances, please explain how PGE estimated the deferred taxes by plant vintage for mass property accounts. Was a theoretical reserve calculation performed in developing the vintage data, similar to what is done in preparing PGE's depreciation study? Please explain.**
- **e. Do the referenced amounts include deferred taxes associated with amortization or depreciation of software?**

*Response:*

a. The information provided in UE 335_AWEC DR 017_Attach B_CONF is an output report from our Power Plan Tax Provision system. There are no formulas or links in the work paper because the amounts are embedded in thousands of system calculations.

b. Each line on the report represents an accumulation of temporary differences considered to be either Regulatory Assets (RA) or Regulatory Liabilities (RL) by jurisdiction.

   1. M Item column: The total of all temporary differences related to the regulatory classification/jurisdiction.
   2. Total Tax: Total of current and deferred tax related to the M Items. This is the key column. Without normalization requirements, a temporary difference will create an equal and offsetting current and deferred tax such that the total tax is zero. However, when the ARAM rate associated with the temporary difference is not equal to the current rate, there is a resulting total tax. Thus, the total tax is caused by the ARAM on these temporary items.
   3. Current Impact: The current tax related to the M-Items (at the current tax rate).
   4. Deferred Impact: The deferred impact related to the M-Items (new incurring differences at the current rate and reversing differences at the ARAM rate).

c. As required by GAAP, the Excess Deferred Federal Income Tax (EDFIT) is removed from accumulated deferred income tax (ADIT). This is accomplished through a debit to FERC account 190: Accumulated Deferred Income Taxes. The offsetting credit is recorded to FERC account 254: Other Regulatory Liabilities.
d. Plant additions are entered into PowerTax through an interface with the Continuing Property Record (CPR). As those records are entered into PowerTax, PowerTax creates a vintage record by Tax Class. Book depreciation is one of the factors in calculating the turnaround of plant temporary differences. Tax Classes are grouped into Book Depreciation Groups that are the same Book Depreciation Groups that are in the plant depreciation module. Book depreciation is loaded into PowerTax by Book Depreciation Group through an interface with the plant depreciation module. Book depreciation is allocated to the vintage Tax Class records using a similar method to the plant depreciation module depreciation calculation. The book depreciation reserve in PowerTax is reconciled to the FERC book depreciation reserve as reported in the FERC Form 1 annually.
e. Yes, the referenced amounts include deferred taxes associated with amortization or depreciation of software.

May 18, 2018

TO: Hayley Thomas
Davison Van Cleve, P.C.

FROM: Stefan Brown
Manager, Regulatory Affairs

**PORTLAND GENERAL ELECTRIC**
**UE 335**
**PGE Response to AWEC Data Request No. 099**
**Dated May 4, 2018**

**Request:**

**Please identify the ratemaking methodology that PGE is currently using to recover severance payments associated with the Boardman retirement.**

*Response:*

Forecasted severance payments related to the cessation of coal-fired operations at Boardman are being collected through PGE Schedule 145 and are not included in the UE 335 revenue requirement.

May 18, 2018

TO: Hayley Thomas
Davison Van Cleve, P.C.

FROM: Stefan Brown
Manager, Regulatory Affairs

**PORTLAND GENERAL ELECTRIC**
**UE 335**
**PGE Response to AWEC Data Request No. 100**
**Dated May 4, 2018**

**Request:**

**Reference PGE's response to ICNU data request 10, Attachment A: Please provide an explanation for the deferred tax item titled "Stock Incentive Plan RMGMT", including a description of both the expense timing for book purposes and the deduction timing for tax purposes.**

*Response:*

The deferred tax item titled "Stock Incentive Plan RMGMT" represents the timing difference of when the costs of stock incentive plans are recorded for book versus tax. For book purposes these costs are expensed, straight line, over the vesting period. For tax purposes, the costs are deducted on the vesting date. The difference in timing between when the expense is recognized for book and tax purposes, creates a temporary difference that results in a deferred tax asset or liability.

May 18, 2018

TO: Hayley Thomas
Davison Van Cleve, P.C.

FROM: Stefan Brown
Manager, Regulatory Affairs

**PORTLAND GENERAL ELECTRIC**
**UE 335**
**PGE Response to AWEC Data Request No. 104**
**Dated May 4, 2018**

**Request:**

**Reference PGE's response to AWEC data request 45, sup-part C: Please provide detail for each unprotected book-tax difference item, indicating, as of December 31, 2017, the amount of accumulated deferred taxes before re-measurement at the 21% federal income tax rate, the amount of accumulated deferred federal income taxes after re-measurement, and the re-measurement gain or loss, which PGE appears to have recorded on its books in 2017.**

*Response:*

Attachment 104-A provides a list of all book-tax differences, the accumulated deferred income tax (ADIT) before re-measurement, and the ADIT after re-measurement. The re-measurement loss recorded on the books as of December 31, 2017 is $16,893,465, which is in cell F190 of Attachment104-A.

Attachment 104-A is protected information and subject to Protective Order No. 18-047.

May 18, 2018

TO: Hayley Thomas
Davison Van Cleve, P.C.

FROM: Stefan Brown
Manager, Regulatory Affairs

**PORTLAND GENERAL ELECTRIC**
**UE 335**
**PGE Response to AWEC Data Request No. 105**
**Dated May 4, 2018**

**Request:**

**Reference PGE's response to AWEC data request 45, sup-part C: Did PGE record a regulatory liability when it amortized the re-measurement gains associated with unprotected EDFIT in 2017? If yes, please provide workpapers supporting the calculation of the regulatory liability.**

*Response:*

The total re-measurement of the "unprotected" deferred income tax balance resulted in a loss of $16,327,486. AWEC Data Request No. 104, Attachment 104-A, provides the calculation for that amount (sum of cells F187 and G187). Of the $16,327,486 re-measurement of unprotected deferred items, $565,978 was recorded as a regulatory liability as of December 31, 2017 (cell F189).

May 18, 2018

TO: Hayley Thomas
Davison Van Cleve, P.C.

FROM: Stefan Brown
Manager, Regulatory Affairs

**PORTLAND GENERAL ELECTRIC**
**UE 335**
**PGE Response to AWEC Data Request No. 106**
**Dated May 4, 2018**

**Request:**

**Reference PGE's response to AWEC data request 25:**

a) **Please provide the monthly transfers to plant, by project, for 2015 in the same format as the attachments to the referenced data request.**
b) **Please also consolidate the capital additions from 2017 into a single workpaper.**
c) **For the capital additions provided for calendar years 2015 through 2017, please identify each project by function, in the same manner as done for the 2018 capital additions in response to AWEC data request 26.**

*Response:*

Attachment 106-A provides the 2015-2017 Monthly Plant Additions to address parts (a) through (c). Asset Retirement Cost (ARC) associated with the Asset Retirement Obligations (ARO) have been excluded from all monthly plant additions data.

**Company** **Portland General Electric**
**Ferc Activity Code** **Addition**
**Year** **2017**

| **Funding Project System Number** | **Funding Project Description** | **Function** | **201701** | **201702** | **201703** | **201704** | **201705** | **201706** | **201707** | **201708** | **201709** | **201710** | **201711** | **201712** | **Grand Total** |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| P14628 | Replace Failed Underground Cables | Distribution Plant | $ 543,037 | $ 1,145,481 | $ 1,326,555 | $ 807,697 | $ 740,165 | $ 1,487,091 | $ 1,175,888 | $ 1,899,578 | $ 1,486,084 | $ 1,699,029 | $ 1,133,774 | $ 1,273,289 | $ 14,717,667 |
| P14757 | Underground Locating | Distribution Plant | $ (3,506) | $ 4,691 | $ 57,002 | $ 17,502 | $ 29,435 | $ 178,645 | $ (86,062) | $ 73,474 | $ 121,662 | $ (112,386) | $ 25,308 | $ 60,739 | $ 366,503 |
| P16567 | T&D System Major Maintenance-UG | Distribution Plant | $ 7,258 | $ 49,751 | $ 11,116 | $ 6,350 | $ 1,977 | $ 2,395 | $ 26,469 | $ 23,033 | $ 4,985 | $ 29,273 | $ 29,459 | $ 50,993 | $ 243,059 |
| P17443 | T&D Major System Inspect, Replace | Distribution Plant | $ 356,091 | $ 381,371 | $ 722,035 | $ 656,810 | $ 746,663 | $ 1,795,006 | $ 871,625 | $ 1,412,528 | $ 1,198,882 | $ 1,143,871 | $ 1,131,463 | $ 1,198,942 | $ 11,615,286 |
| P19712 | Underperforming Feeder Improvements | Distribution Plant | $ 63,594 | $ 264 | | | $ 3,118 | $ 4,186 | $ 3,765 | $ 16,790 | $ 2,435 | $ 16,252 | $ 54,852 | $ 204,091 | $ 369,346 |
| P20340 | Faraday-Replace Runner Unit #6 | Hydro Production | | $ 8,437 | | | | | | | | | | | $ 8,437 |
| P20482 | Middle Grove Conversion | Distribution Plant | | | | | $ (114) | | | | | | | | $ (114) |
| P22449 | P22449 Colstrip Capital Proj PPL | Steam Production | $ 769,586 | $ (65,813) | $ 3,532,799 | $ (83,398) | $ 6,939 | $ 22,063 | $ 86,463 | $ 435,251 | $ 8,445,097 | $ 1,921,181 | $ 112,228 | $ 3,574,988 | $ 18,757,384 |
| P22727 | Pelton/Round Butte PME - Lower Rive | Intangible Plant | | | | | | $ 20,152 | $ 6,750 | $ 8,137 | $ 28,153 | $ (18) | $ 189 | $ 64,069 | $ 127,433 |
| P22771 | PRB PME - Habitat Fund | Intangible Plant | $ 167,144 | $ 1,333 | | | | | $ 66,670 | | | $ (43) | $ - | $ - | $ 235,105 |
| P22840 | Replace/Rewind Failed Sub Transfrmr | Distribution Plant | | | $ 2,328,250 | $ 15,500 | $ 63,813 | $ 32,768 | $ 1,191,096 | $ 2,173 | $ 2,929 | $ 2,336 | $ 2,809 | $ 2,652 | $ 3,644,327 |
| P23077 | Horizon 230kV - Phase 1 Constructio | Distribution Plant | | | | | $ 509 | $ 19 | | $ 125 | | $ 541 | $ - | $ (515) | $ 679 |
| P23098 | Replace Obsolete Relays | Distribution Plant | | | | | | | $ 421 | $ 174 | | $ - | $ - | $ 3,283 | $ 3,879 |
| P23367 | FY-Replace Relays | Hydro Production | | | | | $ 26 | | | $ 756 | | | | | $ 781 |
| P23438 | Various Substations - Install SCADA | General Plant | | | | | $ 464 | | | | | | | | $ 464 |
| P23528 | Clackamas PME - Recreation, Aesthet | Hydro Production | $ 1,465 | $ 26 | $ 3,644 | $ 5,956 | $ 10,260 | $ 145,997 | $ 60,131 | $ 7,202 | $ 1,220 | $ 186,683 | $ 185,464 | $ 9,001 | $ 617,049 |
| P23631 | Clackamas PME - Mitigation Fund | Intangible Plant | | | | | $ 2,451,045 | $ (787,732) | $ 151,637 | | $ 271,837 | $ - | $ 860,523 | $ - | $ 2,947,310 |
| P23754 | AMI - Advanced Metering Infrastruct | Intangible Plant | | $ (8,512) | | | | | | | | $ - | $ - | $ 45 | $ (8,467) |
| P23813 | Cornell Substation - Construct New | Distribution Plant | | | | | | | | $ 7,446 | | $ 8,209 | $ - | $ - | $ 15,654 |
| P23970 | Corporate Strategic Fiber Project | General Plant | | $ (133) | $ 367,872 | $ 81 | $ 23,732 | $ 2,581 | $ 4,627 | $ 3,777 | $ (16) | $ (4,052) | $ 2,875 | $ 908,406 | $ 1,309,749 |
| P24723 | Substation Arc Flash Mitigation | Distribution Plant | | | $ - | | | | $ 341 | $ 4,565 | | $ 4,952 | $ 4,014 | $ 797,184 | $ 811,056 |
| P24995 | PRB Water Fund | Intangible Plant | $ (166,675) | | | | | | | $ 333,350 | | | | | $ 166,675 |
| P25093 | PRBF 2007-07 Flymon Stewardship Pro | Intangible Plant | | $ 63 | $ (63) | | | | | | | | | | $ 1 |
| P25177 | Network Infrastructure Fitness | General Plant | $ 46,209 | $ 40,347 | $ (47,254) | $ 59,299 | $ 4,400 | $ 5,430 | $ 2,227 | $ 2,446 | | | | | $ 113,103 |
| P25246 | Pelton/Round Butte PME - Land Use | Hydro Production | $ - | | | $ 6,243 | $ 33 | | | | | | | | $ 6,276 |
| P25499 | Gen Plants-Instl Transf Gas Mon | Transmission Plant | $ 4,702 | | $ - | $ - | $ - | | | | | | | | $ 4,702 |
| P25502 | Server Infrastructure Fitness | General Plant | $ 208,276 | $ 85,809 | $ 35,157 | $ 65,783 | $ 3,283 | | | $ (228,928) | $ 28,677 | $ 81,653 | $ 223,442 | $ 470,216 | $ 973,370 |
| P25665 | Clackamas PME - Lower River Gravel | Intangible Plant | $ 8 | $ 1,520 | $ 111 | | | | | | | | | | $ 1,639 |
| P26261 | Mt Hood Corridor Reliability Projec | General Plant | $ (303) | $ (27) | | | $ 92 | $ (3) | $ 59 | | | $ 2,658 | $ (808) | $ - | $ 1,669 |
| P26416 | Clackamas PME - Habitat Improvement | Intangible Plant | | | $ - | | $ 66,187 | $ (2) | $ 68,498 | $ 22,049 | $ 608 | $ (1) | $ 94,648 | $ 151,759 | $ 403,746 |
| P26611 | Printing Svcs Production Paper Fold | General Plant | | | | | $ 9,559 | $ 1,373 | $ 57 | $ (67) | $ (25) | $ (49) | $ 24 | $ 48 | $ 10,921 |
| P26698 | Solar - Feed In Tariff (FIT) | Distribution Plant | | | | | | $ 22 | | $ 906 | $ 1 | | | | $ 929 |
| P26749 | Upgrade Hydro SCADA Control Systems | Hydro Production | | $ 312 | $ (4,344) | | | | | | | | | | $ (4,032) |
| P27149 | DSG Dispatchable Standby Generation | Other Production | $ 667,719 | $ 2,443 | $ 176,865 | $ 19,963 | $ 6,777 | $ 3,349 | $ 3,287 | $ 1,928 | $ 9,958 | $ 3,003 | $ 2,564 | $ 13,430 | $ 911,284 |
| P35040 | Feeder Monitoring | Distribution Plant | | $ 463 | $ 148 | $ 435 | $ 88 | $ (4) | $ 4 | $ (5) | $ (2) | $ 490 | $ 2 | $ 4 | $ 1,623 |
| P35070 | Vehicle Vintage Replacement | General Plant | $ 349,320 | $ 453,740 | $ 513,512 | $ 461,432 | $ 1,324,920 | $ 208,948 | $ 82,353 | $ 448,663 | $ 249,763 | $ 1,076,460 | $ 1,081,446 | $ 1,428,281 | $ 7,678,839 |
| P35085 | Substation Fitness | Distribution Plant | $ 98,576 | $ 29,407 | $ (599) | $ (1,118) | $ (284) | $ 480 | $ 5,609 | $ 155,570 | $ (2,438) | $ (1,685) | $ - | $ 9,399 | $ 292,919 |
| P35095 | Dist System Line Construction | Distribution Plant | $ 71,086 | $ 133,386 | $ 41,726 | $ (273,035) | $ 189,109 | $ 132,433 | $ 64,983 | $ 109,567 | $ (295,708) | $ 61,398 | $ 59,944 | $ (241,166) | $ 53,721 |
| P35096 | Dist Customer Line Construction | Distribution Plant | $ 208,099 | $ 309,422 | $ 309,655 | $ 114,382 | $ 323,429 | $ 221,800 | $ (449,102) | $ 112,015 | $ 90,213 | $ 98,329 | $ 116,919 | $ 120,119 | $ 1,575,281 |
| P35101 | Sunset - Replace WR1 Transformer | Distribution Plant | | | | | | | | $ 3,732 | | | | | $ 3,732 |
| P35149 | Colstrip Transmission NW Energy | Transmission Plant | | $ 23,004 | $ 28,786 | $ 45,351 | $ 54,753 | $ 14,428 | $ 76,257 | $ 3,799 | $ 43,326 | $ 14,839 | $ 25,568 | $ 23,997 | $ 354,107 |
| P35150 | BR - Replace HRSG Superheaters | Other Production | $ 9,411 | $ 4,883 | $ 742 | $ 446 | | | | | | $ - | $ 6,006,730 | $ 552,412 | $ 6,574,624 |
| P35155 | Install NERC CIP Substation Access | Distribution Plant | | | $ 1,842 | $ (25) | $ 3 | $ (6) | $ 5 | $ (5) | $ (2) | $ (4) | $ 2 | $ 4 | $ 1,812 |
| P35172 | PSES - Generation Fitness Fund | Other Production | $ 97,966 | $ 105,141 | $ 374,434 | $ 30,676 | $ 89,278 | $ 1,147,492 | $ 283,610 | $ 221,835 | $ 262,467 | $ 402,399 | $ 326,834 | $ 1,084,253 | $ 4,426,388 |
| P35210 | BN Capital Tools & Lab Equip | General Plant | $ 6,174 | $ 16,081 | $ 16,293 | $ (22,374) | $ 6,772 | $ (8,685) | $ 204 | $ 20,601 | $ 14,738 | $ 2,494 | $ 4,133 | $ 5,727 | $ 62,158 |
| P35211 | RB - Switchyard Upgrades | Hydro Production | $ (75) | $ 8 | $ (8) | | | | | | $ (23) | | | | $ (98) |
| P35212 | Misc. Pumps, Valves, Motors | Other Production | | | $ 13,125 | | $ 73,553 | $ 8,627 | $ 142,574 | $ 8,631 | $ 8,906 | $ 15,998 | $ 75,251 | $ 12,672 | $ 359,337 |
| P35214 | BN - Misc. Pumps. Valves, Motors | Steam Production | $ 2,762 | $ 5,444 | $ 9,163 | $ 51,531 | $ 47,591 | $ 57,569 | $ 5,202 | $ 37,484 | $ 15,140 | $ 1,518 | $ 20,639 | $ 1,645 | $ 255,691 |
| P35217 | Generation Cap Tools & Lab Equip | General Plant | $ 69,409 | $ 77,645 | $ 55,463 | $ 43,896 | $ 25,113 | $ 85,488 | $ 26,966 | $ 9,264 | $ (60,845) | $ 6,693 | $ 4,998 | $ 167,214 | $ 511,303 |
| P35221 | PRB Capital Tools & Lab Equip | General Plant | $ 7,006 | $ (144) | $ 2,409 | $ 1,733 | | | | | | $ - | $ - | $ 41,138 | $ 52,143 |
| P35228 | Clackamas PME Road Fund | Intangible Plant | | | | | | | | $ 168,025 | $ 6,894 | $ 1,133 | $ 23 | $ 184,915 | $ 360,990 |
| P35329 | Blue Lake/Gresham - System Upgrades | General Plant | $ (95,457) | $ 205,346 | $ 76,966 | $ 21,536 | $ 70,728 | $ 17,785 | $ 14,968 | $ 88 | $ 44,096 | $ 26,124 | $ 463 | $ 201 | $ 382,846 |
| P35349 | Dist Line Sys - Equip Replacement | Distribution Plant | $ 88,101 | $ 71,573 | $ 22,963 | $ 9,395 | $ 1,501 | $ 33,071 | $ 3,541 | $ 45,775 | $ 52,234 | $ 59,858 | $ 36,197 | $ 23,344 | $ 447,554 |
| P35388 | Sunset Sub - Linde 35kV Feeder | Distribution Plant | | $ (444) | | | | $ (4) | | | | | | | $ (448) |
| P35393 | Install Automatic Gen Cntrl Equip | Other Production | | | $ 1,449 | | $ - | | | | | | | | $ 1,449 |
| P35407 | 2020 Vision Wave 2 -MMS,GIS,OMS | General Plant | $ - | | $ 25,527 | | | $ 3,900 | | | | $ - | $ - | $ 3,044 | $ 32,471 |
| P35479 | TASNET SCADA System Replacement | General Plant | | $ 1,000,179 | $ 633 | $ 7,782 | $ 927 | $ 671 | $ (31) | $ (559) | $ 166 | $ 5,499 | $ - | $ 1,216,171 | $ 2,231,439 |
| P35484 | 230kV Pole Replacements | Transmission Plant | | | | $ 0 | $ (0) | | | | $ 43,788 | $ (78) | $ 119 | $ (44) | $ 43,784 |

| Funding Project System Number | Funding Project Description | Function | 201701 | 201702 | 201703 | 201704 | 201705 | 201706 | 201707 | 201708 | 201709 | 201710 | 201711 | 201712 | Grand Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| P35485 | Replace Remaining D1D Cables | Distribution Plant | | $ (1,065) | | | | $ (9) | | | | | | | $ (1,074) |
| P35501 | Hayden Island Substation Upgrades | Distribution Plant | | | $ 18 | | | $ 0 | | | | | | | $ 19 |
| P35514 | OG - Build Harriet Power House | Hydro Production | | $ 1,672 | $ 924 | $ 1,608 | $ (31) | $ (22) | $ (24) | | | | | | $ 4,128 |
| P35522 | Desktop Computer Fitness Program | General Plant | $ 30,667 | $ 15,115 | $ 3,547 | $ 25,930 | $ 198,119 | $ (1,190) | $ 7,902 | $ (4,075) | $ (210) | $ 457 | $ 106 | $ 4,331 | $ 280,698 |
| P35542 | BR: Purchase Communication Radios | General Plant | | | | | | | $ (22) | | | | | | $ (22) |
| P35553 | BR - Replace 4.16 kV Switchgear | Other Production | | | $ (7,979) | | | | | | | | | | $ (7,979) |
| P35554 | Voice Replacement with Cisco Voip | General Plant | | | | | | | | | $ 546 | $ (2) | $ 200,541 | $ 1,243 | $ 202,328 |
| P35556 | Avian Protection Program | Distribution Plant | $ 16,636 | $ 8,010 | $ 26,896 | $ 46,685 | $ 23,085 | $ 42,558 | $ 33,301 | $ 34,792 | $ 31,134 | $ 42,100 | $ 11,672 | $ 25,328 | $ 342,196 |
| P35565 | PSES - Generation Site Paving | Hydro Production | $ 2,686 | $ (1) | $ (2) | $ 1,431 | $ 82,981 | $ (0) | $ 85,965 | $ 101,674 | $ (32) | $ 29 | $ 218,815 | $ 174,405 | $ 667,951 |
| P35570 | West Union - 115kV Conversion | Distribution Plant | | $ 1,975 | $ 12 | $ 0 | $ - | | | | | $ 1,939 | $ - | $ 1,534,123 | $ 1,538,049 |
| P35571 | Shute Substation - Build New Sub | Distribution Plant | $ 3,549 | | $ 25,465 | | $ - | $ 0 | | | $ 568 | | | | $ 29,582 |
| P35572 | Build New Rock Creek Substation | Distribution Plant | | $ 312 | $ 22,006 | $ 781 | $ 92,088 | $ 752 | $ 24,896 | $ (35) | $ 97,724 | $ 567 | $ 123,730 | $ 620 | $ 363,443 |
| P35573 | Ruby - 115kV Conversion | Distribution Plant | | | | | | | | $ 25 | | | | | $ 25 |
| P35591 | As-Built Drawings - Generation | Hydro Production | $ 117,237 | $ 131,475 | $ 61,624 | $ 68,913 | $ 29,535 | $ 67,523 | $ 30,235 | $ 10,145 | $ 23,486 | $ 65,004 | $ 69,068 | $ 120,731 | $ 794,975 |
| P35619 | CET Install Oracle CC&B/MDM Systems | General Plant | $ 328,636 | $ 54,377 | $ 32,989 | $ 4,512 | $ 2,066,799 | $ 287,270 | $ (58,932) | $ 918,711 | $ 46,617 | $ 59,548 | $ 263,799 | $ 963,879 | $ 4,968,204 |
| P35631 | Sunset - D1X Transformer Upgrades | Distribution Plant | $ 31,559 | $ 5,121 | $ 7,015 | $ 3,389 | $ 19,512 | $ 8,139 | $ (1,495) | $ (5,295) | | $ - | $ - | $ 53 | $ 67,997 |
| P35650 | Emergent Radio Equipment | General Plant | $ 258 | $ 2,882 | $ 1,361 | $ 2,543 | $ 10,835 | $ 6,395 | $ 4,192 | $ 4,754 | $ 1,327 | $ (2,985) | $ 550 | $ 337 | $ 32,448 |
| P35666 | Build Fiber Route West on HWY 26 | General Plant | | | | | | $ 565,072 | $ 5,735 | $ 5,090 | $ 759 | $ 795 | $ 99 | $ 28 | $ 577,577 |
| P35669 | Underground Core Crew Bldg Purchase | General Plant | | | $ 2,514 | | | | | | | | | | $ 2,514 |
| P35672 | ETRM Risk Management Consolidation | General Plant | $ (43,313) | $ 150,638 | $ (70,385) | $ (16,427) | $ 44,715 | $ (743) | $ 14 | $ (16) | | | | | $ 64,483 |
| P35679 | Construct Marquam Project | General Plant | $ 271,904 | $ 28 | | | $ - | $ 0 | $ 58 | | | $ - | $ - | $ 290,486 | $ 562,475 |
| P35683 | EMS Readiness Center Enhancement | General Plant | $ 2,914 | $ 2,567 | $ 2,931 | $ 4,357 | $ 1,258 | $ 462 | $ 321 | $ 1,001 | $ (5) | $ (54) | $ 37 | $ 38 | $ 15,829 |
| P35688 | BI & Data Managment for PGE | Intangible Plant | $ 14,760 | | $ 5,613 | | | | | | | | | | $ 20,373 |
| P35692 | CET - IVR Fitness - Remove Barriers | Intangible Plant | $ (69,617) | $ (40,106) | $ 7,384 | $ (133,230) | | | | | $ 170,600 | | | | $ (64,968) |
| P35706 | Web CMS Replacement | Intangible Plant | | | $ 5,940 | $ 12,150 | | $ 9,660 | $ 2,490 | | | $ - | $ 1,260 | $ - | $ 31,500 |
| P35709 | Replace Emergency Generators-WTC | Other Production | | | $ 9,706 | | | | | | | | | | $ 9,706 |
| P35760 | Build Fiber Port Westward - Rainier | General Plant | | | | | | | $ 11,467 | | $ 5,608 | | | | $ 17,075 |
| P35769 | Construct Carty Generating Plant | Other Production | $ (1,666,154) | $ (201,001) | $ 3,757,763 | $ (546,877) | $ 176,671 | $ (878,530) | $ 203,080 | $ 1,021,868 | $ 1,127,795 | $ (387,968) | $ 7,534 | $ 296,095 | $ 2,910,277 |
| P35782 | Relocate Hillsboro Customer Office | General Plant | $ (0) | | | | | | | | | | | | $ (0) |
| P35802 | Horizon Phase II Project | Distribution Plant | $ 16,590 | $ 813,203 | $ 18,098 | $ 26,511 | $ 5,005 | $ 57,266 | $ (269) | $ 12,786,030 | $ 94,729 | $ 8,122,738 | $ 4,490,288 | $ 179,816 | $ 26,610,005 |
| P35815 | Abernethy Substation Capacity Addn | Distribution Plant | $ 4,164,721 | $ 8,077 | $ 103,076 | $ (190) | $ 9,643 | $ 1,401 | $ 1,840 | $ 134,284 | $ 55,144 | $ 34,732 | $ 39,101 | $ - | $ 4,551,828 |
| P35820 | Estacada Capacity Addition | Distribution Plant | $ 966,967 | $ 132,610 | $ 213,179 | $ 69 | $ (1,133) | $ 712 | $ (493) | $ (544) | | $ 99,610 | $ 278 | $ 425 | $ 1,411,680 |
| P35828 | Faraday Switchyard 115kV Upgrade | General Plant | | | $ (13) | | $ 2 | $ (0) | $ 1,758 | | $ (1) | | | | $ 1,745 |
| P35831 | X-Phase Synchrophasor Installation | Transmission Plant | $ 1,522 | $ 8,717 | $ 146 | $ 3 | $ 2,032 | $ 4,400 | $ 41 | $ (41) | $ 22 | $ (27) | $ 31 | $ 0 | $ 16,847 |
| P35834 | Round Butte Transmission Upgrades | General Plant | | $ 63,997 | | $ - | | | $ (144) | | | | | | $ 63,852 |
| P35835 | Portland Service Center Upgrade | General Plant | $ 2,432 | $ 2,621 | $ 864 | | | $ (0) | | | | | | | $ 5,917 |
| P35842 | N. Plains - Pumpkin Ridge Recond. | Distribution Plant | $ 864 | $ 1,923 | $ 22,833 | $ (225) | $ (106) | $ 122 | $ (56) | $ (55) | $ 16 | $ 1,562 | $ 31 | $ 783 | $ 27,691 |
| P35844 | Corporate Furniture Purchases | General Plant | $ 651 | | | | | | | | | | | | $ 651 |
| P35846 | CPP Switch Replacement | Distribution Plant | $ 32,225 | $ 1,555 | $ 5,843 | $ 62,192 | $ 1,456 | $ 7,792 | $ (166) | $ (426) | $ 40,263 | $ 101,602 | $ 38,910 | $ 121,179 | $ 412,425 |
| P35849 | PeopleSoft HR 9.2 Upgrade | General Plant | $ 3,663 | $ 6,453 | $ 170,989 | $ 2,441 | $ 420 | $ 2,975,251 | $ 133,182 | $ 1,120 | $ (1,134) | $ 47,191 | $ 1,080 | $ 388,365 | $ 3,729,021 |
| P35853 | PeopleSoft Financials 9.2 Upgrade | Intangible Plant | $ 314,650 | $ (234,458) | $ 216,913 | $ (353,293) | $ (7) | | | | | | | | $ (56,194) |
| P35855 | AMI Infrastructure Improvements | General Plant | $ 106,824 | $ 41,651 | $ 52,728 | $ 56,013 | $ 18,208 | $ 32,705 | $ 20,922 | $ 47,261 | $ 53,231 | $ 39,866 | $ 9,842 | $ 8,402 | $ 487,653 |
| P35860 | Application Password Vaulting | General Plant | | | | | | | | | $ 55,098 | $ 225,230 | $ - | $ 3,684,394 | $ 3,964,722 |
| P35861 | Network Access Management | General Plant | $ 13,070 | $ 30,539 | $ (357) | $ (138) | $ (64) | $ (26) | $ 369,380 | | | $ 103 | $ - | $ - | $ 412,508 |
| P35866 | App Segmentation | Intangible Plant | $ 1,085,167 | $ 1,519 | $ 34,781 | $ (39,292) | $ 304 | $ 29,189 | $ 338 | $ 1,946 | | | | | $ 1,113,952 |
| P35881 | IT for Facilities & Communications | General Plant | $ 5,412 | $ 16,375 | $ 1,427 | $ 11,771 | $ 2,141 | $ 2,131 | $ 9,744 | $ 13,961 | $ 4,716 | $ 26,439 | $ 6,290 | $ 6,562 | $ 106,969 |
| P35890 | Purchase Distribution Transformers | Distribution Plant | $ 1,037,259 | $ 1,467,879 | $ 987,629 | $ 199,229 | $ 338,065 | $ 640,276 | $ 911,016 | $ 1,024,271 | $ 566,273 | $ 886,787 | $ 1,011,535 | $ 780,337 | $ 9,850,556 |
| P35892 | Purchase Customer Meters | Distribution Plant | $ 689,272 | $ 120,646 | $ 110,415 | $ 398,878 | $ 182,016 | $ 250,257 | $ 189,105 | $ 1,016,396 | $ 210,919 | $ 121,860 | $ 314,007 | $ 179,444 | $ 3,783,214 |
| P35894 | Communications Fitness | General Plant | $ 249,887 | $ 118,234 | $ 130,671 | $ 328,998 | $ 79,793 | $ 147,347 | $ 83,152 | $ 40,161 | $ 100,714 | $ 67,936 | $ 225,524 | $ 830,916 | $ 2,403,333 |
| P35902 | CIP System Upgrades | General Plant | | $ (136,026) | | | $ - | | | | | | | | $ (136,026) |
| P35907 | Barnes Battle Creek Reconductor | Distribution Plant | $ 11,944 | $ 172 | $ (188) | $ (83) | $ (39) | $ 25 | $ (21) | | | | | | $ 11,810 |
| P35908 | SAM: Proactive UG Cable Program | Distribution Plant | $ 239,809 | $ 1,736,236 | $ 993,010 | $ 1,421,651 | $ 4,264,140 | $ (4,896,531) | $ 2,078,277 | $ 825,327 | $ 1,943,253 | $ 1,501,733 | $ 1,065,070 | $ 534,089 | $ 11,706,064 |
| P35910 | KB Pipe: Dewater Allen Bros Slope | Other Production | | | $ 78 | | | | | | | | | | $ 78 |
| P35914 | Substation Fitness 2015-2018 | Distribution Plant | $ 400,980 | $ 209,250 | $ 151,586 | $ 79,450 | $ 89,165 | $ 695,430 | $ 65,481 | $ 43,180 | $ 368,306 | $ 528,184 | $ 131,961 | $ 1,284,933 | $ 4,047,906 |
| P35916 | PW: Install Modular CT Insulation | Other Production | | | | | | $ 1,312,457 | $ 9,478 | $ (188) | $ (27,839) | $ (137) | $ 47 | $ 93 | $ 1,293,911 |
| P35920 | Corporate Security SoftwareFailover | Intangible Plant | $ 40 | $ 2,608 | | | | | | | | $ - | $ - | $ 440 | $ 3,088 |
| P35924 | Distribution System Construction II | Distribution Plant | $ 1,873,085 | $ 2,487,904 | $ 4,567,156 | $ 5,154,640 | $ 5,071,381 | $ 9,276,280 | $ 2,838,746 | $ 4,905,040 | $ 5,308,182 | $ 2,173,503 | $ 4,056,034 | $ 3,722,908 | $ 51,434,860 |
| P35925 | Dist. Customer Line Construction II | Distribution Plant | $ 2,847,941 | $ 2,234,546 | $ 2,605,413 | $ 2,196,334 | $ 1,958,351 | $ 5,373,339 | $ 1,867,445 | $ 2,219,002 | $ 3,261,076 | $ 1,331,004 | $ 2,651,846 | $ 3,143,743 | $ 31,690,040 |
| P35932 | Upgrade Maximo for IT | Intangible Plant | | | | | | $ 1,106,497 | $ 960 | $ (893) | $ (319) | $ (621) | $ 251 | $ 10,746 | $ 1,116,621 |
| P35937 | NF: Generator 2 Rewind | Hydro Production | $ 857 | $ 22 | $ 1,694 | $ (1) | $ 711 | $ (4) | $ 4 | | | | | | $ 3,283 |
| P35943 | RB: Install Xfrmr Depressurization | Transmission Plant | | $ 820 | $ 2,567 | $ 150 | | | | | | | | | $ 3,537 |
| P35946 | RB: Replace VAR-4 Transformer | Transmission Plant | $ 11,087 | $ 14,084 | $ 785 | $ (1,855) | $ (19) | $ (9,883) | | | $ (107) | | | | $ 14,091 |

| Funding Project System Number | Funding Project Description | Function | 201701 | 201702 | 201703 | 201704 | 201705 | 201706 | 201707 | 201708 | 201709 | 201710 | 201711 | 201712 | Grand Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| P35956 | BR: Upgrade MCC's for HRSG's | Other Production | $ 47,251 | $ 40,190 | $ 18,697 | $ (980) | $ 2,637 | $ 6,473 | $ 3,652 | | | $ - | $ 579,536 | $ 176,728 | $ 874,184 |
| P35959 | WSH Structural/Reliability Upgrades | Hydro Production | $ (98,011) | $ 44,262 | $ 96,340 | $ 8,712 | $ 47,684 | $ 208,976 | $ 1,523,259 | $ 18,175 | $ 226,853 | $ 5,663,764 | $ 148,767 | $ 3,218,996 | $ 11,107,778 |
| P35980 | PCB Transformer Replacement | Distribution Plant | $ 601,902 | $ 645,749 | $ 1,035,338 | $ 981,189 | $ 1,257,423 | $ 1,610,706 | $ 1,135,092 | $ 1,632,335 | $ 1,386,654 | $ 1,556,039 | $ 1,160,164 | $ 1,187,305 | $ 14,189,896 |
| P35995 | Downtown UG Core Cable Replacement | Distribution Plant | $ 110,119 | $ 110,279 | $ 2,641 | $ (1,459) | $ 119,776 | $ 300,036 | $ 101,965 | $ 70,542 | $ 215,489 | $ 239,805 | $ 232,037 | $ 116,209 | $ 1,617,438 |
| P36003 | NERC CIPv5 Compliance Program | General Plant | $ - | | $ 1,202 | $ - | | | | | | | | | $ 1,202 |
| P36015 | Remediation/Decom Vacant Land | General Plant | $ (1,059) | $ 13 | $ (35) | $ (13) | $ (6) | $ (3) | $ 3 | | | | | | $ (1,101) |
| P36019 | Hemlock substation Install ATS | General Plant | $ (374) | $ 1,562 | $ (61) | $ 3,680 | $ 1,426 | | | $ 0 | $ 924 | $ 11,064 | $ 5 | $ 8 | $ 18,235 |
| P36020 | BLC Video Conference System | General Plant | | $ 4,302 | $ - | | | | | | | | | | $ 4,302 |
| P36036 | Canemah-Sullivan 57kV Project | General Plant | $ 7,906 | $ 61,629 | $ 33,693 | $ 28,305 | $ 16,496 | $ 5,759 | $ 4,074,243 | $ 212,502 | $ 37,471 | $ 126,554 | $ 96,381 | $ 1,079,903 | $ 5,780,842 |
| P36039 | Harborton Reliability Project | Distribution Plant | | | $ 2,680,258 | $ (493,020) | $ 75,116 | $ 42,140 | $ 633 | $ (1,555) | $ 2,977 | $ 1,640 | $ 3,694 | $ - | $ 2,311,882 |
| P36042 | Tektronix Substation Upgrade | Distribution Plant | | | $ 3,557,113 | $ 72,634 | $ 13,415 | $ 6,421 | $ 286 | $ 549 | $ 7,951 | $ 186,692 | $ 4,295,197 | $ 533,321 | $ 8,673,578 |
| P36043 | Reconductor Pleasant Valley Baxter | Distribution Plant | | | $ 606,663 | $ 43,891 | $ (838) | $ 648 | $ (527) | $ (438) | $ 146 | $ (276) | $ - | $ - | $ 649,269 |
| P36046 | Corporate Security Fitness | General Plant | $ 1,324 | | $ 13,981 | $ 39,694 | $ 2,229 | $ 59,997 | $ 25,058 | $ 116,203 | $ 4,586 | $ 1,732 | $ 25,764 | $ 58,171 | $ 348,739 |
| P36047 | Eastport Comm Ofc Relocate &Upgrade | General Plant | | | | | | $ 443,176 | $ 253 | $ 1,419 | $ (8) | $ 5,674 | $ 75 | $ 73 | $ 450,663 |
| P36052 | Tualatin (TCC) Facilities Upgrade | General Plant | $ 1,800 | $ 20,704 | $ 1,562,038 | $ (2,974) | $ 153,332 | $ (827,297) | $ 65 | $ (272) | $ 70 | $ (200) | $ 205 | $ 36 | $ 907,505 |
| P36054 | CyberSecurity Fitness | General Plant | $ 54,734 | $ 25,796 | $ (996) | $ 2,024 | $ 114,807 | $ 4,831 | $ 247,572 | $ 61,158 | | $ 485 | $ - | $ - | $ 510,411 |
| P36055 | Corporate Security Failover Part II | General Plant | $ 35,648 | $ 26,912 | $ 3,086 | $ 31,375 | $ 1,348 | | $ 29,335 | $ (354) | $ 279 | $ - | $ - | $ 321,367 | $ 448,995 |
| P36056 | Upgrade/Add Revenue Meters | Transmission Plant | $ 931,677 | $ 17,780 | $ 42,015 | $ 1,171,806 | $ 235,786 | $ 407,679 | $ 281,596 | $ 18,394 | $ 36,145 | $ 490,816 | $ 125,898 | $ 471 | $ 3,760,062 |
| P36061 | BR: CTG Rewind Program 2016 - 2018 | Other Production | $ 5,200 | $ 7,292 | $ (762) | | | | $ 3,637,015 | $ 734 | $ 84,446 | $ 18,294 | $ 12,322 | $ 683 | $ 3,765,223 |
| P36062 | RB: Airgap Monitor Upgrade RealTime | Hydro Production | | | $ 257,175 | $ (663) | $ (307) | $ (82) | $ 90 | $ (148) | $ 780 | $ 983 | $ 1,074 | $ 1,027 | $ 259,929 |
| P36065 | Capital Furniture Purchases | General Plant | $ 9,463 | | | | | | | | | | | | $ 9,463 |
| P36067 | PGE Facilities Fitness | General Plant | $ 470,049 | $ 1,103 | | $ 0 | $ (0) | | | | | | | | $ 471,152 |
| P36074 | Repl Meters for Trans Manag Sys | Distribution Plant | $ 171,526 | $ 29,078 | $ 430 | $ 10,489 | $ 13,182 | $ 5,179 | $ 1,599 | $ (90) | $ 545 | $ 395 | $ 229 | $ (24) | $ 232,539 |
| P36082 | Purchase Two Repairman Trucks | General Plant | $ 498 | $ 10 | $ (26) | $ (10) | $ (5) | $ (2) | $ 2 | | | | | | $ 466 |
| P36087 | PRB - Misc. Pumps, Valves, Motors | Hydro Production | | | | $ 10,001 | $ 6,313 | $ 1,898 | $ 88 | $ 20 | $ 1,479 | $ (35) | $ 7 | $ 26 | $ 19,798 |
| P36088 | SAM: Rivergate N Substation Rebuild | Transmission Plant | | | $ 356,611 | | | | | | $ 4,662,751 | $ 134,416 | $ 65,930 | $ 12,036 | $ 5,231,744 |
| P36093 | Carver & PSC Pole Yards | General Plant | $ 1,172 | | | | $ - | | | | | | | | $ 1,172 |
| P36101 | Substation Communication Upgrade | General Plant | $ 37,327 | $ 40,032 | $ 36,815 | $ 96,725 | $ 78,579 | $ 123,123 | $ 117,587 | $ 69,448 | $ 265,413 | $ 130,307 | $ 4,289,883 | $ (4,292,021) | $ 993,218 |
| P36105 | 2016/17 Dispatchable Standby Gen | Other Production | $ 308,602 | $ 9,990 | $ 11,458 | $ (43) | $ 209 | $ 4 | $ 10 | | | $ 4,922 | $ 4 | $ 268,676 | $ 603,833 |
| P36106 | UPS Battery/Capacitor Fitness | General Plant | | | | | | $ 1,768 | $ (35) | | | | | | $ 1,733 |
| P36108 | Bdmn-CCR Landfill Wells/SWStruct | Steam Production | | | $ 148,816 | | | | | | | | | | $ 148,816 |
| P36109 | Distribution Automation | General Plant | | | $ 14,633 | $ 31,845 | $ 20,906 | $ 48,840 | $ 107,704 | $ 41,782 | $ 319,577 | $ 357,232 | $ 174,672 | $ 548,565 | $ 1,665,755 |
| P36116 | Wind Generation Fitness Program | Other Production | $ 209,611 | $ 4,644 | $ 942,013 | $ 25,664 | $ 2,773 | $ 217,435 | $ 601,411 | $ 780,353 | $ 291,309 | $ 33,062 | $ 1,740,458 | $ 1,070,698 | $ 5,919,432 |
| P36117 | PW: HP Feedwater Cntrl Valve Replac | Other Production | | | | | | $ 278,245 | $ 1,327 | $ (75) | $ (19) | $ (59) | $ 22 | $ 38 | $ 279,479 |
| P36119 | PN: Reconstruct Shoulder PN Dam Rd | Hydro Production | | | | | | | $ 690,720 | $ 4,099 | $ 483 | $ 433 | $ 113 | $ 134 | $ 695,983 |
| P36122 | Performance & Reliability Software | Intangible Plant | $ 7,636 | $ 4,508 | $ (109,671) | $ 9,091 | $ 142,097 | $ 6,486 | $ 2,640 | $ 49,549 | $ 27,900 | $ 1,002 | $ 13,513 | $ 13,025 | $ 167,777 |
| P36129 | Purchase Truck for PGE Parks | General Plant | | | $ 33,601 | $ (1) | $ 18,173 | $ 3,001 | $ 1 | $ (13) | $ (1) | $ (9) | $ 6 | $ 7 | $ 54,765 |
| P36132 | CS: CTG & STG Protective Relay Upgr | Other Production | | | | | | | | $ 1,674,047 | $ 1,152 | $ (1,859) | $ 779 | $ 918 | $ 1,675,036 |
| P36137 | BR: Upgrade Boiler Feed Pump VSDs | Other Production | $ 34,265 | $ (642) | $ (28) | $ 91 | $ (6) | $ (2) | $ 8,642 | | | | | | $ 42,318 |
| P36145 | Downtown Reach - DSL Easements | Distribution Plant | $ - | | $ 250 | | | $ 1,250 | $ 985 | | | $ - | $ 28,441 | $ 1,000 | $ 31,926 |
| P36166 | Orient sub: Capacity Addition | Distribution Plant | | | | | | | $ 19,509 | $ 2,151 | $ (1) | $ 22,890 | $ 60,203 | $ 22,188 | $ 126,938 |
| P36167 | FY: Repower Faraday Units 1-5 | Hydro Production | | | $ 1,133,224 | $ (1,187) | $ (624) | $ 46 | $ 268 | $ (312) | $ (120) | $ (229) | $ - | $ - | $ 1,131,066 |
| P36169 | PW - Purchase GT Rotor | Other Production | $ 22,813 | | | | | | | | | | | | $ 22,813 |
| P36170 | OHSU Infrastructure Upgrades | Distribution Plant | $ 2,187 | $ 3,005 | $ 5,303 | $ (185) | $ 3,922 | $ 349 | $ 105 | $ 1,861 | $ (16) | $ 539 | $ 947,234 | $ 69,830 | $ 1,034,135 |
| P36180 | Purchase SDPM Field Vehicles | General Plant | | $ 25,820 | $ 797 | $ 938 | $ 10,783 | $ 2 | $ 561 | $ (8) | $ 298,903 | $ 70,180 | $ 61,296 | $ 7,161 | $ 476,432 |
| P36187 | Construct RPM Center | Other Production | $ 464 | $ 633 | $ (14) | $ (13) | $ 103 | $ (2) | $ 2 | $ 73 | | | | | $ 1,247 |
| P36189 | PACE HR | Intangible Plant | $ 19,367 | $ 22,931 | $ 23,612 | $ 14,136 | $ 14,762 | $ 504,671 | $ 19,406 | $ (392) | $ (140) | $ (272) | $ 110 | $ 307 | $ 618,498 |
| P36190 | PACE Finance- Supply Chain | Intangible Plant | $ 46,625 | $ 19,479 | $ 10,833 | $ 17,913 | $ 7,968 | | | | | | | | $ 102,818 |
| P36192 | PACE Governance | Intangible Plant | | | | | | $ 487,023 | $ 9,484 | $ (273) | $ (98) | $ (190) | $ 77 | $ 214 | $ 496,237 |
| P36193 | Energy Network Redesign | General Plant | $ (138,518) | $ 26,885 | $ (46,331) | $ 34,298 | $ 32,662 | $ 36,921 | $ 6,290 | $ 35,518 | $ 20,519 | $ 2,099 | $ 27,370 | $ 1,259 | $ 38,972 |
| P36195 | PACE - Finance - Financials | Intangible Plant | | | | | | $ 337,636 | $ 87,296 | $ 48,445 | $ (124) | $ 26,030 | $ 16,558 | $ 11,804 | $ 527,645 |
| P36205 | Metal Streetlight Grounding | Distribution Plant | | | | | | | | $ 9,758 | $ 40,380 | $ 320,339 | $ 215,863 | $ (1,467) | $ 584,873 |
| P36208 | Mt. Scott Comm Tower Upgrade | General Plant | $ 48,201 | | | | | | | | | | | | $ 48,201 |
| P36213 | Upgrade UG Streetlight Circuits | Distribution Plant | $ 32,450 | $ 9,114 | | | | | | | | | | | $ 41,564 |
| P36214 | Grand Ronde-Substation Interconnect | Distribution Plant | | | | | | $ 118,961 | $ (86) | $ (151) | $ 53 | $ 496 | $ 106 | $ 22 | $ 119,401 |
| P36215 | Purchase Compact Track Loader | General Plant | | | $ 67,808 | | | | | | | | | | $ 67,808 |
| P36220 | Wind: Install AGC equipment for EIM | Other Production | | | | | | $ 103,657 | $ 133 | $ 11 | $ (46) | $ 68,128 | $ 116 | $ - | $ 171,998 |
| P36222 | Legacy Tool Replacement Project | General Plant | | | $ 928,505 | $ 1,596 | $ 2,507 | $ 134,409 | $ 39,198 | $ 19,927 | $ 3,791 | $ 31,885 | $ 17,862 | $ - | $ 1,179,681 |
| P36224 | Replace ITIM | General Plant | | | | | | | | $ 14,016 | $ 1,516 | $ 4,341 | $ 4,192 | $ 7,114 | $ 31,179 |
| P36225 | Comm-Purchase Mobile Radio Tower | General Plant | $ 1,137 | $ 53 | $ 278 | $ 7,608 | $ 1,451 | $ 64 | $ (58) | $ (53) | $ 16 | $ (33) | $ 31 | $ 12 | $ 10,506 |
| P36227 | Kelly Creek Culvert Replacement | Distribution Plant | $ 919 | $ 24 | $ (66) | $ (25) | $ (12) | $ (5) | $ 5 | | | | | | $ 841 |
| P36228 | Generation Cyber Security NIDs | Other Production | $ 363 | $ 31,928 | $ 73,966 | $ 481 | $ 22,630 | $ 23,208 | $ 3,034 | $ 9,340 | $ 41,130 | $ 357,050 | $ 44,470 | $ 8,276 | $ 615,877 |

| Funding Project System Number | Funding Project Description | Function | 201701 | 201702 | 201703 | 201704 | 201705 | 201706 | 201707 | 201708 | 201709 | 201710 | 201711 | 201712 | Grand Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| P36229 | McGill Sub Capacity Additions | Distribution Plant | | | | | | | 8,560 | 3,842 | 1,886 | 180,719 | 58,019 | 1,163,143 | 1,416,169 |
| P36234 | Install Storeroom Pole Bunkers | General Plant | | | | 69,742 | 34,281 | 54,210 | | - | 4,511 | 3,708 | 18,724 | - | 185,177 |
| P36235 | Install Low OH Services Guarding | Distribution Plant | 161 | 10,966 | 75,103 | | | 50,200 | 47,586 | | 69,233 | 10,828 | 6,957 | 152,635 | 423,669 |
| P36239 | Purchase SCADA Tech Van | General Plant | | 63 | 45,150 | 1,236 | (11) | 8 | (7) | (6) | 2 | (4) | 4 | 1 | 46,436 |
| P36246 | Malin Physical Security Upgrades | Transmission Plant | 6,821 | (6,960) | | - | | | | | | | | | (139) |
| P36251 | Shute WJ2 Switchgear | Distribution Plant | 121,264 | 383,623 | 5,897 | 15,110 | 8,852 | (1,602,801) | 305,022 | (501) | 280 | 1,071,636 | 399 | (12) | 308,769 |
| P36255 | Substation-Purchase SF Cart | General Plant | | | | 189,991 | 239 | | | | | | | | 190,230 |
| P36257 | 2017 Purchase Corporate Furniture | General Plant | | | | 103,605 | | 52,640 | 11,966 | 18,917 | | 13,158 | 833 | 1,698 | 202,817 |
| P36260 | 2017 Facilities Capital Fitness | General Plant | | | | | 29,303 | 23,351 | 297,529 | | 173,418 | 38,795 | 168,321 | 280,307 | 1,011,025 |
| P36280 | Purchase Mobile Transformers | Distribution Plant | | | | 2,171,423 | 9,236 | 2,169,343 | 2,530 | 199,405 | 11,641 | 6,114 | 496 | 4,464,895 | 9,035,084 |
| P36283 | Comm Tech Dept - Buy Test Equipment | General Plant | | | 33,244 | | | 29,434 | 58 | (0) | (0) | (0) | 23,195 | 74,790 | 160,720 |
| P36284 | 2017 Server Fitness | General Plant | 13,777 | 157,414 | 203,757 | 184,231 | 2,222,395 | 844,743 | (151,996) | 576,965 | 1,076,730 | 374,999 | 463,427 | 378,782 | 6,345,224 |
| P36285 | T&D - Capital Tools & Lab Equipment | General Plant | 181 | 583 | 21,691 | 136 | 12,298 | 213,536 | (9,762) | 28,098 | 113,411 | 7,965 | 22,301 | (7,108) | 403,329 |
| P36286 | 2017 Network Fitness | General Plant | 11,045 | 981,767 | 608,930 | 525,855 | 196,675 | 200,093 | (30,606) | 439,272 | 151,151 | 231,510 | 85,019 | 948,656 | 4,349,369 |
| P36287 | 2017 Cyber Security Fitness | General Plant | 21,758 | | | 34,251 | 3,573 | 125,818 | 38,113 | 36,902 | 7,887 | 16,638 | 17,960 | 51,439 | 354,339 |
| P36288 | 2017 Desktop Fitness | General Plant | 388,638 | 273,240 | 474,074 | 535,548 | 256,012 | 180,508 | 38,445 | 142,509 | 538,606 | 208,051 | 622,229 | 552,973 | 4,210,833 |
| P36292 | CS: Upgrade Compressor to allow Fog | Other Production | | | | | | 685,638 | 23 | (32) | (10) | (24) | 5 | 18 | 685,618 |
| P36305 | BC - Replace Climb Assist | Other Production | | | | | 3,373 | 110 | 220,607 | 12,980 | 6,627 | 12,152 | 131,735 | 66 | 387,651 |
| P36306 | BR: Purchase GT Capital Spares | Other Production | | 138,727 | 232,760 | 412,925 | 58,965 | 28,132 | | | | | | | 871,509 |
| P36307 | PRP - Vehicles & Capital Equipment | General Plant | 35,691 | 45,450 | 168,779 | 149,875 | 122,565 | 88,567 | 72,340 | 1,479 | 3,698 | 65,450 | 132,382 | 552,260 | 1,438,536 |
| P36311 | PSES - Generation Fitness Fund | General Plant | - | | | | | | | | 79,056 | 19,105 | - | - | 98,160 |
| P36325 | Install Datapower Devices | General Plant | 322,779 | 6,812 | 4,685 | 5,038 | 4,089 | 5,836 | 1,354 | (25) | (60) | (114) | 55 | 113 | 350,563 |
| P36326 | Install Datapower Devices | Intangible Plant | - | | | | | | | 159 | 1,053,935 | 147,666 | 1,442 | 417,895 | 1,621,098 |
| P36330 | Carty - Purchase Vehicles and Lifts | General Plant | 2,810 | 15,595 | 641 | 9,496 | 705 | (3) | 3 | (20) | (3) | (14) | 9 | 11 | 29,230 |
| P36340 | PowerPlan Upgrade & Lease Module | Intangible Plant | | | | | 850,455 | 205,727 | 6,406 | 20,994 | 12,504 | (347) | (6) | 3,436 | 1,099,169 |
| P36351 | Purchase Splicer Trailer | General Plant | | | | | | | | 29,203 | 45 | (4) | 142 | 4 | 29,390 |
| P36353 | NF: Install Fish Ladder Pumps | Hydro Production | | | | | | | | | 996,473 | (1,063) | 40,098 | 836 | 1,036,344 |
| P36357 | Purchase OSISoft Licenses | General Plant | | | | | | | | | 15,450 | - | (15,450) | 2,594,246 | 2,594,246 |
| P36358 | Purchase IT Storage for Critical Sy | General Plant | | 2,142 | 46,198 | 172,494 | 2,031,587 | 23,851 | 51,452 | 288,263 | 12,834 | 37,541 | 17,997 | 45,419 | 2,729,779 |
| P36360 | TCC Skylight Replacements | General Plant | | | | | | | | | 93,278 | | | | 93,278 |
| P36365 | CY: Complete Carty As-Builts | Other Production | | | 40,998 | 2,224 | 121,218 | 205,179 | 77,312 | 6,692 | 13,586 | (5,309) | 3,352 | 10,427 | 475,678 |
| P36367 | ELS Trailer for PRB Biologists | General Plant | | | | | 3,119 | | | | | | | | 3,119 |
| P36371 | CIP Low Impact Security Substations | General Plant | | | | | | | 3,854 | | | 2,388 | 6 | 56,886 | 63,134 |
| P36383 | Replace Gresham Entry Stairs | General Plant | | | | | | | | 64,286 | 221,486 | (198,428) | 2 | 4 | 87,350 |
| P36393 | McLoughlin Storage Yard Expansion | Distribution Plant | | | | | | | | 886,912 | 5,158 | (94) | 15,202 | 12,587 | 919,765 |
| P36407 | Automate Development Operations | General Plant | | | | | | 198,069 | | | | | | | 198,069 |
| P36409 | RM: Upgrade Attraction Water Pumps | Hydro Production | | | | | | | | | 253,150 | (79) | 2,692 | 2,543 | 258,307 |
| P36488 | Furniture - Staff Growth (TDRI) | General Plant | | | | | | | | | 65,315 | | | | 65,315 |
| P19344 | Underperforming Feeders | Distribution Plant | | | | | | | | | | 608 | - | - | 608 |
| P21342 | HR PeopleSoft Migration | General Plant | | | | | | | | | | - | 611 | - | 611 |
| P22722 | Pelton/Round Butte PME - Recreation | Intangible Plant | | | | | | | | | | - | - | 162,625 | 162,625 |
| P22723 | Pelton/Round Butte PME - Aquatic Re | Hydro Production | | | | | | | | | | - | - | 72,131 | 72,131 |
| P26959 | Communications Vintage and Growth | General Plant | | | | | | | | | | 25,917 | - | - | 25,917 |
| P35139 | Facilities Fitness | General Plant | | | | | | | | | | 987 | - | - | 987 |
| P35200 | Build Combined Back-Up Facility | General Plant | | | | | | | | | | (2,398) | - | - | (2,398) |
| P35459 | Virtual Deskptop Infrastructure | General Plant | | | | | | | | | | - | - | 28,200 | 28,200 |
| P35487 | Oswego-West Ptld 115kV Reconductor | Distribution Plant | | | | | | | | | | 18 | - | - | 18 |
| P35684 | Web Fitness- Rmv Self Svc Barriers | Intangible Plant | | | | | | | | | | - | 3,720 | - | 3,720 |
| P35859 | 1WTC03 Floor Upgrade | General Plant | | | | | | | | | | - | 110 | - | 110 |
| P35873 | Certificate Management Phase II | Intangible Plant | | | | | | | | | | - | - | 375 | 375 |
| P35933 | Kelley Point Pad-Switch Replacement | Distribution Plant | | | | | | | | | | - | 10,859 | - | 10,859 |
| P35938 | Field Voice Communications System | General Plant | | | | | | | | | | - | - | 8,996,015 | 8,996,015 |
| P35939 | Replace KB Line Heater at Beaver | Other Production | | | | | | | | | | - | - | (6,427) | (6,427) |
| P35975 | Substation Interconnection Const | General Plant | | | | | | | | | | - | - | (26,140) | (26,140) |
| P36005 | Spectrum - 700mhz | Intangible Plant | | | | | | | | | | - | 5,938,311 | 0 | 5,938,311 |
| P36044 | 3WTCPL Upgrade | General Plant | | | | | | | | | | 3,631 | 10,035 | 50,203 | 63,868 |
| P36133 | WSH: Upgrade Comm. Infrastructure | General Plant | | | | | | | | | | - | - | 2,101,703 | 2,101,703 |
| P36138 | PW2 Add Blackstart Capability | Transmission Plant | | | | | | | | | | - | - | 2,764,485 | 2,764,485 |
| P36146 | Energy Market Readiness Project | Intangible Plant | | | | | | | | | | 10,209,457 | 1,257,922 | 1,135,940 | 12,603,319 |
| P36179 | EMS Upgrades for EIM | Intangible Plant | | | | | | | | | | 631,023 | 768,004 | 60,962 | 1,459,988 |
| P36218 | Upgrade 3WTCBR Control Room | General Plant | | | | | | | | | | - | - | 95,127 | 95,127 |
| P36223 | Replace Primary Cables Ronler Acres | Distribution Plant | | | | | | | | | | - | - | 715,122 | 715,122 |

| Funding Project System Number | Funding Project Description | Function | 201701 | 201702 | 201703 | 201704 | 201705 | 201706 | 201707 | 201708 | 201709 | 201710 | 201711 | 201712 | Grand Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| P36236 | Purchase laptops/monitors - FASuite | General Plant | | | | | | | | | | $ - | $ 42,680 | $ - | $ 42,680 |
| P36252 | Sunset WR2 DGA Monitor | Distribution Plant | | | | | | | | | | $ - | $ - | $ 117,915 | $ 117,915 |
| P36262 | Newberg Traffic Signal Modification | General Plant | | | | | | | | | | $ - | $ - | $ 328,764 | $ 328,764 |
| P36271 | OG: Timothy Spillway Modifications | Hydro Production | | | | | | | | | | $ 1,236,845 | $ 2,816 | $ 396,503 | $ 1,636,164 |
| P36273 | Replace Glendoveer-Gresham 115kV | Distribution Plant | | | | | | | | | | $ 2,893,084 | $ 549,502 | $ 173,111 | $ 3,615,697 |
| P36276 | Workplace EV Charging Phase 2 | General Plant | | | | | | | | | | $ 467 | $ 1 | $ 17,655 | $ 18,122 |
| P36290 | BR: Replace second VFD for BFP | Other Production | | | | | | | | | | $ - | $ - | $ 365,155 | $ 365,155 |
| P36293 | BR - Replace Steam Turbine ETD | Other Production | | | | | | | | | | $ 363,898 | $ 34,254 | $ 212,928 | $ 611,080 |
| P36301 | SN: Throat Liner Unit 13 | Hydro Production | | | | | | | | | | $ 1,124,588 | $ 72,635 | $ 11,605 | $ 1,208,829 |
| P36338 | BR: Unit 8 Repair | Other Production | | | | | | | | | | $ - | $ - | $ 2,634,947 | $ 2,634,947 |
| P36339 | PSC Transformer Shop Enclosure | General Plant | | | | | | | | | | $ - | $ - | $ 357,862 | $ 357,862 |
| P36354 | Spectrum - 200mhz | Intangible Plant | | | | | | | | | | $ - | $ - | $ 1,992,070 | $ 1,992,070 |
| P36370 | IVR Development Environment | Intangible Plant | | | | | | | | | | $ - | $ - | $ 313,903 | $ 313,903 |
| P36373 | Blue Lake Phase II | Distribution Plant | | | | | | | | | | $ 15,100 | $ 40,715 | $ - | $ 55,815 |
| P36403 | Build Sheep Solar Interconnect | Distribution Plant | | | | | | | | | | $ - | $ 2,941 | $ 12,944 | $ 15,885 |
| P36412 | Incremental Added Vehicles | General Plant | | | | | | | | | | $ - | $ - | $ 27,173 | $ 27,173 |
| P36415 | PACE - Enterprise Data Warehouse | Intangible Plant | | | | | | | | | | $ - | $ - | $ 867,949 | $ 867,949 |
| P36451 | CY: Upgrade Heat Trace System | Other Production | | | | | | | | | | $ - | $ - | $ 503,996 | $ 503,996 |
| P36454 | Substation Rerock - multiple sites | Distribution Plant | | | | | | | | | | $ 340,541 | $ 379,315 | $ 967,562 | $ 1,687,418 |
| P36487 | PGE Safety - Vehicle for Generation | General Plant | | | | | | | | | | $ - | $ - | $ 27,173 | $ 27,173 |
| P36489 | T&D Application Reliability Imprvmt | General Plant | | | | | | | | | | $ 759 | $ 6,623 | $ 655 | $ 8,037 |
| P36490 | Build WTC Integrated Sec Ops Ctr | General Plant | | | | | | | | | | $ 9,461 | $ 108,696 | $ 158,350 | $ 276,507 |
| P36498 | Silverton West Feeder Reconductor | Distribution Plant | | | | | | | | | | $ - | $ - | $ 143,153 | $ 143,153 |
| P36506 | Customer Touchpoints infrastructure | General Plant | | | | | | | | | | $ - | $ - | $ 708,112 | $ 708,112 |
| | **Grand Total** | | **$ 20,618,021** | **$ 16,623,340** | **$ 39,806,938** | **$ 17,828,836** | **$ 29,543,701** | **$ 30,450,121** | **$ 26,601,408** | **$ 38,173,411** | **$ 38,589,246** | **$ 51,036,117** | **$ 52,012,593** | **$ 74,411,270** | **$ 435,320,051** |

May 18, 2018

TO: Hayley Thomas
Davison Van Cleve, P.C.

FROM: Stefan Brown
Manager, Regulatory Affairs

**PORTLAND GENERAL ELECTRIC**
**UE 335**
**PGE Response to AWEC Data Request No. 107**
**Dated May 4, 2018**

**Request:**

**Reference PGE's response to AWEC data request 26, project P35619 (the "Oracle Project"):**

a) **Is this project the entirety of the amounts for the Customer Information System (CIS) and Meter Data Management System (MDMS) described in PGE/900?**
b) **Please provide the monthly CWIP balances associated with this project, for each month prior to being transferred to plant.**
c) **Has the referenced project been placed into service? If yes please identify the go live date, along with the total amount of capital transferred to plant. If no, please provide the latest estimate on when the Oracle Project will be completed, as well as the latest estimate of total capital costs.**
d) **Please identify the gross plant of PGE's existing billing system, meter data management systems, and any other systems that will be obsolete as a result of completing the Oracle Project.**

*Response:*

a) P35619, CET Install Oracle CC&B/MDM Systems, is the entirety of the amounts for the Customer Information System (CIS) and Meter Data Management System (MDMS) described in PGE Exhibit 900, Section III. Attachment 107-A provides the project description and justification.
b) Attachment 107-B provides monthly CWIP Balances May 2015-April 2018.
c) Project P35619 in total is expected to be completed in Q3 2018. The replacement of the legacy CIS and MDMS are the major components of the project (Customer Touchpoints), and those two went live on May 14th, 2018. The amount initially transferred to plant, exclusive of trailing capital costs, will be known when the May books are closed. There project will incur additional capital costs during the stabilization months following the May 14th go live. The estimate of total capital costs is $153,942,650.

d) Attachment 107-C provides capitalized costs and software programs replaced by the installation of the Oracle CIS and MDMS. All of these costs have been fully amortized as of year-end 2017. PGE amortizes software using either a 5-year life or a 10-year life.

May 18, 2018

TO: Hayley Thomas
Davison Van Cleve, P.C.

FROM: Stefan Brown
Manager, Regulatory Affairs

**PORTLAND GENERAL ELECTRIC**
**UE 335**
**PGE Response to AWEC Data Request No. 108**
**Dated May 4, 2018**

**Request:**

**Reference PGE's response to AWEC data request 26, project P35679 (the "Marquam Project"):**

**a) Please provide a narrative description of this project**
**b) Please provide monthly CWIP balances associated with the Marquam Project.**
**c) Please provide the latest estimate on when the Marquam Project will be completed, as well the latest estimate of total capital costs.**

*Response:*

a) The Marquam Project includes a new 115kV state-of-the-art substation and two feeders to: (1) increase capacity due to growth in the South Waterfront area and (2) replace aging infrastructure nearing the end of its service life in downtown Portland. The substation contains gas insulated switchgear that allows us to fit the project within the small size of the property footprint. A new 115kV transmission line is constructed inside the Tilikum Crossing Bridge and continues underground into the Marquam Substation. Two ¾-mile long underground distribution feeders run from the substation to downtown Portland on Naito Pkwy and 1st Ave.
b) Attachment 108-A provides monthly CWIP Balances for P35679, Construct Marquam Project, through April 2018.
c) The Marquam Substation was completed and went in service in April 2018. The overall Marquam project is expected to be completed in Q2 2019. The latest estimate of total capital costs for the Marquam project is $82,929,785.

May 29, 2018

TO: Hayley Thomas
Davison Van Cleve, P.C.

FROM: Stefan Brown
Manager, Regulatory Affairs

**PORTLAND GENERAL ELECTRIC**
**UE 335**
**PGE Response to AWEC Data Request No. 116**
**Dated May 15, 2018**

**<u>Request:</u>**

**Reference PGE's Response to AWEC DR No. 083, Attachment 083-A CONF:**

a. **Please provide the context behind the referenced power point slide and provide a copy of the entire presentation.**
b. **Does PGE's rate case capital forecast include the project changes described as "$6.6 million in funding to cover 5-week go-live delay and reestablish project contingency funding."?**

*<u>Response:</u>*

a. Attachment 116-A provides the complete presentation from which the slide was obtained. The slide is also in PGE's response to OPUC Data Request No. 270, part (t). The presentation was at a Finance Committee Meeting on April 24, 2018. The Finance Committee meets on a regular basis to review project budgets and scope. They are provided with regular updates on various aspects of projects including status of budget, issues, risk, and timeline updates. Attachment 116-A is protected information and subject to Protective Order 18-047.
b. PGE's rate case capital forecast does not include the described project changes. PGE's deferral filing for Customer Touchpoints (UM 1948) includes this additional capital amount.

May 29, 2018

TO: Hayley Thomas
Davison Van Cleve, P.C.

FROM: Stefan Brown
Manager, Regulatory Affairs

**PORTLAND GENERAL ELECTRIC**
**UE 335**
**PGE Response to AWEC Data Request No. 120**
**Dated May 15, 2018**

**Request:**

**Reference FERC Account 407.0001, Amort Of UnrecvPlt-Troj Decomm:**

a. **Please explain how PGE developed the amortization forecast for this account in the test period.**
b. **Please provide workpapers for the forecasted amortization of $2,500,000 in the test period, along with the forecasted amortization and balance calculations through the life of the decommissioning trust.**

*Response:*

a) PGE updated the Trojan model for the latest Trojan Nuclear Decommissioning Trust (NDT) balances, expected rate of return on trust assets, cost estimates, and other parameters. Please see all the update actions performed by PGE in the "Model Update Actions" tab in the Trojan model provided as Attachment 120-A.

b) Attachment 120-A provides the work papers included in the Trojan model. Please note that to model a zero dollar balance of the Trojan NDT in 2034,[1] PGE would have to set the Trojan annual accrual at approximately $1.8 million. However, because PGE is currently in the process of renewing our Nuclear Regulatory Commission license at Trojan for an additional 40 years, which will add considerable uncertainty associated with the spent nuclear fuel at the Trojan site, PGE proposes at this time an annual accrual of $2.5 million.

Attachment 120-A is protected information subject to Protective Order No. 18-047.

[1] The year that is currently modeled for the Trojan nuclear decommissioning completion.

May 24, 2018

TO: Hayley Thomas
Davison Van Cleve, P.C.

FROM: Stefan Brown
Manager, Regulatory Affairs

**PORTLAND GENERAL ELECTRIC**
**UE 335**
**PGE Response to AWEC Data Request No. 121**
**Dated May 15, 2018**

**Request:**

**Reference PGE/200 workpaper "Exhibit Support 2019_Tax Plan", Tab "Rate Base Data" Incentives Adjustment (UE 283 - $10 Million over 20 Years). Please identify the line item where the corresponding amortization of this regulatory liability has been reflected in operating results, and provide detail to demonstrate that the amortization has been included.**

*Response:*

PGE inadvertently did not include the amortization entry in its initially filed UE 335 revenue requirement. PGE will, however, include a $500,000 adjustment to reduce amortization expense as part of its next revenue requirement update in the UE 335 proceeding.

May 29, 2018

TO: Hayley Thomas
Davison Van Cleve, P.C.

FROM: Stefan Brown
Manager, Regulatory Affairs

**PORTLAND GENERAL ELECTRIC**
**UE 335**
**PGE Response to AWEC Data Request No. 122**
**Dated May 15, 2018**

**Request:**

**Reference PGE/200 workpaper, "Exhibit Support 2019_Tax Plan, Tab "Rate Base Data," "Dispatchable Generation." Please identify the order where the Dispatchable Generation regulatory asset was approved and provide workpapers supporting the balance and the amount that PGE proposes to amortize to rates in this matter.**

*Response:*

PGE's Dispatchable Standby Generation (DSG) program pays participating customers owning large, diesel-powered generators for fuel and routine maintenance costs in exchange for access to generator output during times when the PGE grid needs extra power. The DSG program began in the late 1990s as a research and development initiative. Page 11 of the Public Utility Commission of Oregon Order No. 01-777 (Docket No. UE 115) approved and acknowledged PGE's DSG program.

Internally approved and built DSG projects have been included in PGE's rate base through our general rate case process. PGE reports various statistical information about each DSG facility on pages 410/411 FERC Form 1, Generating Plant Statistics (Small Plants). Over time, PGE is incorporating DSG projects as part of the integrated resources plan (IRP) goals (i.e. 2014 IRP).

Attachment 122-A provides the Dispatchable Standby Generation year-end 2018 forecast.
Attachment 122-A is protected information and subject to Protective Order No. 18-047

May 29, 2018

TO: Hayley Thomas
Davison Van Cleve, P.C.

FROM: Stefan Brown
Manager, Regulatory Affairs

**PORTLAND GENERAL ELECTRIC**
**UE 335**
**PGE Response to AWEC Data Request No. 123**
**Dated May 15, 2018**

**Request:**

**Reference PGE/200 workpaper, "Exhibit Support 2019_Tax Plan" Tab "A&G":**

a. **Please provide a description of the following three items included on the referenced tab: Revolver Fees, Margin Net Interest, Broker Fees.**
b. **Please provide the historical amounts paid with respect to Revolver Fees, Margin Net Interest, Broker Fees over the period 2015, 2016, and 2017.**
c. **Please describe the accounting treatment of costs associated with Revolver Fees, Margin Net Interest, Broker Fees for both book and tax accounting purposes.**
d. **Please identify all legal fees paid with respect to issuing stock over the period 2015, 2016, and 2017, and identify the FERC account to which the responsive legal fees were booked.**
e. **Please identify all legal fees forecast to be paid with respect to issuing stock in the test period.**

*Response:*

a. **Revolver Fees:** Fees paid to the bank to have access to a revolving line of credit facility. Revolver fees include Revolver Extension Fees, Annual Fees, and agent and legal fees.

   The line of credit is used to ensure that the company has access to adequate short term liquidity.

   **Margin Net Interest:** Interest paid to trading counter parties for deposits held as collateral for energy, capacity, transmission, and fuel purchase contracts.

   **Broker Fees:** Fees paid to third party brokers for arranging or locating trades for PGE's merchant organization as well as fees from clearing brokers and exchanges that facilitate trades of energy, capacity, transmission, and fuel related commodities.

b.

| Year | 2015 | 2016 | 2017 |
|---|---|---|---|
| Revolver Fees | $917,153 | $917,153 | $917,153 |

| Year | 2015 | 2016 | 2017 |
|---|---|---|---|
| Margin; Net Interest | $284,141 | $435,070 | $266,161 |

| Year | 2015 | 2016 | 2017 |
|---|---|---|---|
| Broker Fees | $297,816 | $522,042 | $399,990 |

c. **Revolver Fees:** Fees are paid and charged to FERC account 186. The fees are amortized over the life of the credit facility and charged to FERC account 431. There is no difference for book and tax purposes.

**Broker Fees and Margin Net Interest:** Costs associated with broker fees are expensed as part of Administrative and General Expenses. The entry would be to debit expense and credit cash. However, activity related to a clearing broker, including margin net interest expense, will be credited against a margin broker deposit account rather than cash. Margin net interest income is recorded as a credit to Interest Income and a debit to broker margin deposits.

d. PGE did not issue any stock in 2017 and 2016; therefore no legal fees were incurred in those years. In Q2 of 2015, the company issued 10,400,000 shares of common stock. PGE did not incur legal fees in 2015 with respect to issuing stock because the 2015 stock issuance was tied to an Equity Forward Sales Agreement (EFSA) that was executed in conjunction with a prior stock issuance in 2013. Due to the EFSA being in place, PGE did not incur any additional legal fees in 2015.

e. We do not anticipate any legal fees will be allocated to stock issuance in the test year as we are not anticipating any new issuance of authorized shares.

May 24, 2018

TO: Hayley Thomas
Davison Van Cleve, P.C.

FROM: Stefan Brown
Manager, Regulatory Affairs

**PORTLAND GENERAL ELECTRIC**
**UE 335**
**PGE Response to AWEC Data Request No. 126**
**Dated May 15, 2018**

**Request:**

**Please provide the revenue requirement workpapers used to calculate the final stipulated revenue requirement in Docket UE 319.**

*Response:*

Attachment 126-A provides the requested information.

May 29, 2018

TO: Hayley Thomas
Davison Van Cleve, P.C.

FROM: Stefan Brown
Manager, Regulatory Affairs

**PORTLAND GENERAL ELECTRIC**
**UE 335**
**PGE Response to AWEC Data Request No. 129**
**Dated May 15, 2018**

**Request:**

**Reference PGE's response to AWEC Data Request 27, UE 335_AWEC DR 027_Attach A CONF, Project P35980:**

a. **Please state the total number of PCB transformers on the Company's system that have been replaced pursuant to this project as of 12/31/2017.**
b. **Please identify the total number of PCB transformers that PGE still needs to replace for this project.**
c. **Please provide a narrative explaining the overall status of this project.**

*Response:*

a) 2,683 PCB transformers have been replaced as of December 31, 2017.

b) PGE is testing transformers to identify those that need to be replaced. This testing process runs in a parallel process with the replacement of transformers. The current estimate is that there are 6,400 transformers requiring replacement. This is an estimate based upon the current rate of PCB's identified as present in existing transformers.

c) Attachment 129-A provides the up-to-date Funding Project justification for the PCB project P35980 providing discussion, status, and alternatives considered for this project. Testing is planned to be completed in 2020 with replacements of identified transformers completed by year-end 2021.

Attachment 129-A is protected information subject to Protective Order 18-047.

May 29, 2018

TO: Hayley Thomas
Davison Van Cleve, P.C.

FROM: Stefan Brown
Manager, Regulatory Affairs

**PORTLAND GENERAL ELECTRIC**
**UE 335**
**PGE Response to AWEC Data Request No. 131**
**Dated May 15, 2018**

**Request:**

**Reference PGE's response to AWEC Data Request 27, UE 335_AWEC DR 027_Attach A CONF, Project P35938:**

a. **Please provide all internal project justification documentation and presentations with respect to the referenced project, including any benefits studies that were prepared when making the decision to proceed with this project.**
b. **Please state the total amount of capital that has been placed in service for this project, since work on the project was initiated.**
c. **Please provide all change orders that have been submitted with respect to the referenced project.**

*Response:*

PGE objects to this request on the basis that is overly broad and unduly burdensome. Without waiving its objection, PGE responds as follows:

a) Attachment 131-A provides the up-to-date funding project P35938 justification form including project scope, timeline, expected benefits, and project revisions. Also, please see Attachment 131-B for an update presentation provided to PGE's board of directors on February 15, 2017. In addition, PGE will be providing an enterprise communication update in a workshop with stakeholders on June 28, 2018.
b) Total amount of capital that has been placed in service for P35938, Field Voice Communication System, is $12,740,824 as of April 30, 2018. Attachment 131-C, cell G4, provides the total amount that closed to plant by month since December 2017.
c) Attachment 131-A provides all project revisions since the project started in 2014.

Attachments 131-A and 131-B are protected information subject to Protective Order No. 18-047.

May 31, 2018

TO: Hayley Thomas
Davison Van Cleve, P.C.

FROM: Stefan Brown
Manager, Regulatory Affairs

**PORTLAND GENERAL ELECTRIC**
**UE 335**
**PGE Response to AWEC Data Request No. 133**
**Dated May 15, 2018**

**Request:**

**Reference PGE's response to AWEC Data Request 27, UE 335_AWEC DR 027_Attach A CONF, Project P22449:**

a. **Please provide any cost-benefit analyses that PGE has performed to justify making such investments with respect to the referenced project.**
b. **Please identify the Gross Plant balance for Colstrip Units 3 and 4, forecast for December 31, 2018.**
c. **Please identify the Accumulated Depreciation balance for Colstrip Units 3 and 4, forecast for December 31, 2018.**
d. **Please identify the Accumulated Deferred Income Tax balance for Colstrip Units 3 and 4, forecast for December 31, 2018.**
e. **Please identify the Excess Accumulated Deferred Income Taxes balance for Colstrip Units 3 and 4, forecast for December 31, 2018.**
f. **Please identify the Fuel Stock balance for Colstrip Units 3 and 4, forecast for December 31, 2018.**
g. **Please identify the amount of Operating Expenses for Colstrip Units 3 and 4, forecast in the test period.**
h. **Please identify the amount of Taxes Other Than Income Taxes for Colstrip Units 3 and 4, forecast in the test period.**

*Response:*

a) PGE's 20% ownership stake in the Colstrip power plant includes the annual review of the capital and O&M spend with the plant's operator, Talen Energy. PGE's operating agreement with Talen allows for Talen to determine annually what capital work is required to operate the plant safely and reliably within its environmental permitting requirements through its planned operating lifetime. These projects are reviewed with the co-owners prior to annual approval of the site budget.

Specifically, during the annual review of capital in the July and August timeframe, Colstrip capital projects[1] are each discussed with justifications explained to the co-owners by the plant operator in the session noted above. These justifications fall into a number of categories including:

- Regulatory (REG)
- Environmental (ENV)
- Discretionary (DIS)
- Technical (TECH)
- Other (OTR)

For the 2018 capital budget planning year, the only investments in capital are REG, ENV, and OTR. Roughly 60% of the capital budget was allocated to ENV and REG requirements the plant site operator must meet to enable proper operation and decommissioning activities for the facility under its operating license and permits. The balance of the capital expenditures (OTR) is related to overhauls and equipment replacement to ensure safe and reliable operation of plant equipment within its operational license period and currently planned end of life timeline. No investments are being made to increase performance or asset life beyond the currently stated plant operational lifetime.

b) Attachment 133-A provides PGE's estimated gross plant balance for the Colstrip Plant at December 31, 2018.

c) Attachment 133-B provides PGE's estimated depreciation reserve balance for the Colstrip Plant at December 31, 2018.

d) The Accumulated Deferred Income Tax balance for Colstrip Units 3 and 4 forecasted for December 31, 2018 is $25 million. This includes the protected deferred balances after tax reform.

e) The Excess Accumulated Deferred Income Taxes Balance for Colstrip Units 3 and 4 forecasted for December 31, 2018 is $8 million.

f) PGE forecasts the Fuel Stock balance for year-end 2018 to be $3,421,000.

g) PGE forecasts the operating expenses for the 2019 test year to be $22,973,567.

h) The following are Colstrip related taxes other than income taxes:
    - Account 4081003, Property Tax Montana: $5,316,372
    - Account 4081014, Miscellaneous Taxes and Licenses Montana: $432,504 (includes Montana Electrical Energy License Tax)

[1] Referenced in the Project P22449 Justification provided in PGE's response to AWEC Data Request No. 027, Attachment 027-A.

- Account 4081014, Transmission Operation – Transportation of Electricity by Others: $2,412,348 (includes the Beneficial Use Tax for the BPA transmission lines in Montana that is part of PGE's Net Variable Power Cost).

March 29, 2018

TO: Mark Brown
Public Utility Commission of Oregon

FROM: Stefan Brown
Manager, Regulatory Affairs

**PORTLAND GENERAL ELECTRIC**
**UE 335**
**PGE Response to OPUC Data Request No. 128**
**Dated March 15, 2018**

**Request:**

**Please refer to the PGE Exhibit 200 workpaper "2019 Plant Detail.xlsx".**

a. **Please provide the source data file that was used to generate the image on sheet "Carty plant incremental."**
b. **Please provide the source data used to generate the plant balances on sheet "Plant Sum."**
c. **Please provide PGE's actual gross plant, depreciation expense, and accumulated depreciation by plant account and location by month beginning in January 2016. This request is ongoing and should be supplemented July 1, 2018, September 1, 2018, and November 1, 2018.**
d. **Please provide PGE's forecasted gross plant, depreciation expense, and accumulated depreciation by plant account and location by month ending on January 1, 2020. This request is ongoing and should be supplemented July 1, 2018, September 1, 2018, and November 1, 2018.**

*Response:*

Based on a discussion with the OPUC Staff on March 19, 2018, the dates specified for supplemental responses (see parts (c) and (d)) are "file by" dates. Consequently, the information provided by those dates will be as of the most recent month closed for accounting purposes (e.g., the July 1 supplemental response will provide data as of May 31, 2018).

a. In the 2018 Staff Plant Audit AIR 002, PGE described how fixed assets that are currently not included in rate making are reported and how the incremental fixed costs associated with the construction of the Carty Generating Plant are treated. The following table identifies the FERC accounting groups in use for this separation for reporting purposes.

| | |
|---|
| 341-05 Buildings – Carty Incremental |
| 342-05 Fuel holder – Carty Incremental |
| 344-05 Generator Other Prod - Carty Incremental |
| 346-05 Misc Power Plant Equip – Carty Incremental |

The balances in these FERC account groups as of December 31, 2017 are included in Attachment 128-A.

Attachment 128-A is protected and subject to Protective Order No. 18-047.

b. PGE follows the process of either assigning or allocating plant balances. This is performed initially by assigning plant costs directly to the categories Generation, Transmission, Distribution, Metering, Billing, Other Consumer, and Retail. Once this assignment is finished, allocations of remaining plant balance is accomplished through other methods such as identifying general and intangible plant and allocating based on the area of the company that they support. The overall process is to maintain a reasonable allocation method for plant balances year over year.

- Attachment 128-B provides the Major Location and the 300-level FERC account. These costs are directly assigned based on 300-level FERC account and the specifically assigned physical location of the plant balance to the corresponding category within the 300-level FERC account.
- Attachment 128-C Plant Summary forecast is the assignment of the forecasted year end 2018 Plant Balance by classifications. This balance excludes the incremental Carty as identified.
- Attachment 128-D Plant Balance Roll-forward 2018 is the monthly and forecasted year-end 2018 balance distributed through Attachment 128-C Plant Summary.
- Attachment 128 E Detailed Plant Balance for Forecast 2018 represents the forecasted details for Plant summary.

Attachment 128-E is protected and subject to Protective Order No. 18-047

c. See Attachment 128-B for actual monthly 2016 and 2017 gross plant and Attachment 128-F for quarterly depreciation expense and accumulated depreciation for 2016 and 2017.

PGE will provide 2018 monthly actual updates as of May 31, July 31, and Sept 30.

d. Based on clarification with the OPUC Staff on March 22, 2018, since PGE's rate base forecast is as of December 31, 2018, and since no costs from beyond that date are in the UE 335 rate base, then no further information is expected in this response for 2019 costs.

- PGE response to UE 335 ICNU DR 001_Attach A provides PGE's gross utility plant in service forecast, as of December 31, 2018 by FERC account.
- UE 335 ICNU DR 001_Attach B and DR 002 provide PGE's accumulated depreciation and depreciation expense forecast as of December 31, 2018.
- "Ex 203 Depr" and "Ex 204 Amort" tabs in PGE's Exhibit 200 work paper "Exhibit Support 2019_Tax Plan" provide 2018 budget and 2019 forecasted depreciation expense.

PGE will provide 2018 monthly actual updates as of May 31, July 31, and Sept 30.

PLANT BALANCE ROLLFORWARD FOR FORECASTED 2018

| | gl_post_mo_yr | Data | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | 1/1/2018 0:00 | | | | 2/1/2018 0:00 | | | |
| func_class_id | Sum of begin_balance | Sum of additions | Sum of retirements | Sum of end_balance | Sum of begin_balance | Sum of additions | Sum of retirements | Sum of end_balance |
| Distribution Plant | $ 3,534,502,816 | $ 10,391,995 | $ (2,432,652) | $ 3,542,462,158 | $ 3,542,462,158 | $ 15,345,989 | $ (2,432,652) | $ 3,555,375,495 |
| General Plant | $ 550,582,628 | $ 6,773,604 | $ (5,006,619) | $ 552,349,613 | $ 552,349,613 | $ 14,750,424 | $ (5,006,619) | $ 562,093,418 |
| Hydro Production | $ 532,712,715 | $ 107,903 | $ (76,127) | $ 532,744,491 | $ 532,744,491 | $ 134,986 | $ (76,127) | $ 532,803,350 |
| Intangible Plant | $ 606,786,784 | $ 3,526 | $ - | $ 606,790,310 | $ 606,790,310 | $ 3,526 | $ - | $ 606,793,836 |
| Other Production | $ 2,901,961,539 | $ 77,719 | $ - | $ 2,902,039,258 | $ 2,902,039,258 | $ 250,225 | $ - | $ 2,902,289,483 |
| Steam Production | $ 971,591,865 | $ 29,855 | $ (164,805) | $ 971,456,916 | $ 971,456,916 | $ 29,921 | $ (164,805) | $ 971,322,032 |
| Transmission Plant | $ 547,410,320 | $ 50,512 | $ (239,286) | $ 547,221,546 | $ 547,221,546 | $ 53,393 | $ (239,286) | $ 547,035,652 |
| Grand Total | $ 9,645,548,668 | $ 17,435,114 | $ (7,919,489) | $ 9,655,064,293 | $ 9,655,064,293 | $ 30,568,463 | $ (7,919,489) | $ 9,677,713,267 |

Plant Balance Excludes Carty Incremental costs

| | 3/1/2018 0:00 | | | | 4/1/2018 0:00 | | | |
|---|---|---|---|---|---|---|---|---|
| func_class_id | Sum of begin_balance | Sum of additions | Sum of retirements | Sum of end_balance | Sum of begin_balance | Sum of additions | Sum of retirements | Sum of end_balance |
| Distribution Plant | $ 3,555,375,495 | $ 14,011,338 | $ (2,432,652) | $ 3,566,954,181 | $ 3,566,954,181 | $ 60,424,227 | $ (2,432,652) | $ 3,624,945,756 |
| General Plant | $ 562,093,418 | $ 6,871,864 | $ (5,006,620) | $ 563,958,662 | $ 563,958,662 | $ 13,449,826 | $ (5,006,619) | $ 572,401,869 |
| Hydro Production | $ 532,803,350 | $ 167,136 | $ (76,127) | $ 532,894,360 | $ 532,894,360 | $ 192,218 | $ (76,127) | $ 533,010,450 |
| Intangible Plant | $ 606,793,836 | $ 2,121,898 | $ - | $ 608,915,734 | $ 608,915,734 | $ 140,003,526 | $ - | $ 748,919,260 |
| Other Production | $ 2,902,289,483 | $ 1,586,986 | $ - | $ 2,903,876,469 | $ 2,903,876,469 | $ 3,499,261 | $ - | $ 2,907,375,731 |
| Steam Production | $ 971,322,032 | $ 2,550,201 | $ (164,805) | $ 973,707,429 | $ 973,707,429 | $ 30,707 | $ (164,805) | $ 973,573,331 |
| Transmission Plant | $ 547,035,652 | $ 185,670 | $ (239,286) | $ 546,982,036 | $ 546,982,036 | $ 15,550,316 | $ (239,286) | $ 562,293,066 |
| Grand Total | $ 9,677,713,267 | $ 27,495,093 | $ (7,919,490) | $ 9,697,288,871 | $ 9,697,288,871 | $ 233,150,081 | $ (7,919,488) | $ 9,922,519,463 |

Plant Balance Exclu

| | 5/1/2018 0:00 | | | | 6/1/2018 0:00 | | | |
|---|---|---|---|---|---|---|---|---|
| func_class_id | Sum of begin_balance | Sum of additions | Sum of retirements | Sum of end_balance | Sum of begin_balance | Sum of additions | Sum of retirements | Sum of end_balance |
| Distribution Plant | $ 3,624,945,756 | $ 16,310,294 | $ (2,432,652) | $ 3,638,823,399 | $ 3,638,823,399 | $ 29,435,616 | $ (2,432,652) | $ 3,665,826,363 |
| General Plant | $ 572,401,869 | $ 4,122,017 | $ (5,006,620) | $ 571,517,266 | $ 571,517,266 | $ 4,915,904 | $ (5,006,619) | $ 571,426,551 |
| Hydro Production | $ 533,010,450 | $ 100,030 | $ (76,127) | $ 533,034,353 | $ 533,034,353 | $ 2,556,718 | $ (76,127) | $ 535,514,944 |
| Intangible Plant | $ 748,919,260 | $ 1,561,778 | $ - | $ 750,481,038 | $ 750,481,038 | $ 6,605,102 | $ - | $ 757,086,139 |
| Other Production | $ 2,907,375,731 | $ 2,666,632 | $ - | $ 2,910,042,363 | $ 2,910,042,363 | $ 1,271,590 | $ - | $ 2,911,313,952 |
| Steam Production | $ 973,573,331 | $ 30,707 | $ (164,805) | $ 973,439,234 | $ 973,439,234 | $ 2,530,707 | $ (164,805) | $ 975,805,136 |
| Transmission Plant | $ 562,293,066 | $ 52,415 | $ (239,286) | $ 562,106,195 | $ 562,106,195 | $ 897,232 | $ (239,286) | $ 562,764,141 |
| Grand Total | $ 9,922,519,463 | $ 24,843,873 | $ (7,919,490) | $ 9,939,443,846 | $ 9,939,443,846 | $ 48,212,868 | $ (7,919,488) | $ 9,979,737,226 |

Plant Balance Exclu

| | 7/1/2018 0:00 | | | | 8/1/2018 0:00 | | | |
|---|---|---|---|---|---|---|---|---|
| func_class_id | Sum of begin_balance | Sum of additions | Sum of retirements | Sum of end_balance | Sum of begin_balance | Sum of additions | Sum of retirements | Sum of end_balance |
| Distribution Plant | $ 3,665,826,363 | $ 17,157,279 | $ (2,432,652) | $ 3,680,550,989 | $ 3,680,550,989 | $ 13,804,764 | $ (2,432,652) | $ 3,691,923,102 |
| General Plant | $ 571,426,551 | $ 8,719,646 | $ (5,006,620) | $ 575,139,577 | $ 575,139,577 | $ 4,969,186 | $ (5,006,618) | $ 575,102,145 |
| Hydro Production | $ 535,514,944 | $ 350,307 | $ (76,127) | $ 535,789,125 | $ 535,789,125 | $ 1,382,216 | $ (76,127) | $ 537,095,214 |
| Intangible Plant | $ 757,086,139 | $ 166,382 | $ - | $ 757,252,521 | $ 757,252,521 | $ 6,382 | $ - | $ 757,258,903 |
| Other Production | $ 2,911,313,952 | $ 570,445 | $ - | $ 2,911,884,398 | $ 2,911,884,398 | $ 451,509 | $ - | $ 2,912,335,907 |
| Steam Production | $ 975,805,136 | $ 46,146 | $ (164,805) | $ 975,686,477 | $ 975,686,477 | $ 37,107 | $ (164,805) | $ 975,558,780 |
| Transmission Plant | $ 562,764,141 | $ 114,627 | $ (239,286) | $ 562,639,481 | $ 562,639,481 | $ 1,522,194 | $ (239,286) | $ 563,922,389 |
| Grand Total | $ 9,979,737,226 | $ 27,124,832 | $ (7,919,490) | $ 9,998,942,568 | $ 9,998,942,568 | $ 22,173,359 | $ (7,919,488) | $ 10,013,196,439 |

Plant Balance Exclu

| | 9/1/2018 0:00 | | | | 10/1/2018 0:00 | | | |
|---|---|---|---|---|---|---|---|---|
| func_class_id | Sum of begin_balance | Sum of additions | Sum of retirements | Sum of end_balance | Sum of begin_balance | Sum of additions | Sum of retirements | Sum of end_balance |
| Distribution Plant | $ 3,691,923,102 | $ 20,732,606 | $ (2,432,652) | $ 3,710,223,055 | $ 3,710,223,055 | $ 17,006,897 | $ (2,432,652) | $ 3,724,797,300 |
| General Plant | $ 575,102,145 | $ 12,821,683 | $ (5,006,620) | $ 582,917,208 | $ 582,917,208 | $ 4,933,519 | $ (5,006,618) | $ 582,844,109 |
| Hydro Production | $ 537,095,214 | $ 1,273,523 | $ (76,127) | $ 538,292,610 | $ 538,292,610 | $ 122,653 | $ (76,127) | $ 538,339,136 |
| Intangible Plant | $ 757,258,903 | $ 54,668 | $ - | $ 757,313,571 | $ 757,313,571 | $ 787,069 | $ - | $ 758,100,640 |
| Other Production | $ 2,912,335,907 | $ 1,670,695 | $ - | $ 2,914,006,601 | $ 2,914,006,601 | $ 2,415,434 | $ - | $ 2,916,422,036 |
| Steam Production | $ 975,558,780 | $ 2,552,549 | $ (164,805) | $ 977,946,524 | $ 977,946,524 | $ 139,056 | $ (164,805) | $ 977,920,775 |
| Transmission Plant | $ 563,922,389 | $ 3,034,595 | $ (239,286) | $ 566,717,697 | $ 566,717,697 | $ 971,420 | $ (239,286) | $ 567,449,831 |
| Grand Total | $ 10,013,196,439 | $ 42,140,318 | $ (7,919,490) | $ 10,047,417,267 | $ 10,047,417,267 | $ 26,376,047 | $ (7,919,488) | $ 10,065,873,826 |

Plant Balance Exclu

| | 11/1/2018 0:00 | | | | 12/1/2018 0:00 | | | |
|---|---|---|---|---|---|---|---|---|
| func_class_id | Sum of begin_balance | Sum of additions | Sum of retirements | Sum of end_balance | Sum of begin_balance | Sum of additions | Sum of retirements | Sum of end_balance |
| Distribution Plant | $ 3,724,797,300 | $ 10,275,679 | $ (2,432,652) | $ 3,732,640,327 | $ 3,732,640,327 | $ 58,490,280 | $ (2,432,652) | $ 3,788,697,955 |
| General Plant | $ 582,844,109 | $ 3,887,472 | $ (5,006,620) | $ 581,724,960 | $ 581,724,960 | $ 19,312,209 | $ (5,006,618) | $ 596,030,551 |
| Hydro Production | $ 538,339,136 | $ 8,321,729 | $ (76,127) | $ 546,584,738 | $ 546,584,738 | $ 15,506,373 | $ (76,127) | $ 562,014,984 |
| Intangible Plant | $ 758,100,640 | $ 9,911 | $ - | $ 758,110,551 | $ 758,110,551 | $ 20,012,459 | $ - | $ 778,123,010 |
| Other Production | $ 2,916,422,036 | $ 3,333,674 | $ - | $ 2,919,755,710 | $ 2,919,755,710 | $ 7,025,634 | $ - | $ 2,926,781,344 |
| Steam Production | $ 977,920,775 | $ 29,331 | $ (164,805) | $ 977,785,302 | $ 977,785,302 | $ 3,019,860 | $ (164,805) | $ 980,640,357 |
| Transmission Plant | $ 567,449,831 | $ 2,096,141 | $ (239,286) | $ 569,306,685 | $ 569,306,685 | $ 22,479,225 | $ (239,286) | $ 591,546,623 |
| Grand Total | $ 10,065,873,826 | $ 27,953,937 | $ (7,919,490) | $ 10,085,908,273 | $ 10,085,908,273 | $ 145,846,041 | $ (7,919,488) | $ 10,223,834,826 |

Plant Balance Exclu

| func_class_id | Total Sum of additions | | Total Sum of retirements | |
|---|---|---|---|---|
| Distribution Plant | $ | 283,386,963 | $ | (29,191,824) |
| General Plant | $ | 105,527,354 | $ | (60,079,431) |
| Hydro Production | $ | 30,215,791 | $ | (913,522) |
| Intangible Plant | $ | 171,336,226 | $ | - |
| Other Production | $ | 24,819,805 | $ | - |
| Steam Production | $ | 11,026,148 | $ | (1,977,656) |
| Transmission Plant | $ | 47,007,739 | $ | (2,871,436) |
| Grand Total | $ | 673,320,026 | $ | (95,033,868) |

Plant Balance Exclu

**BEFORE THE PUBLIC UTILITY COMMISSION**

**OF OREGON**

**UE 335**

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

**CONFIDENTIAL EXHIBIT NO. AWEC/206**

**CONFIDENTIAL ATTACHMENTS TO DATA RESPONSES**

**(REDACTED VERSION)**

Exhibit AWEC/206 contains Protected Information and has been redacted in its entirety in accordance with Order No. 18-047.

**BEFORE THE**

**PUBLIC UTILITY COMMISSION OF OREGON**

**UE 335**

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

**OPENING RATE CASE TESTIMONY OF**

**DR. MARC M. HELLMAN**

**ON BEHALF OF THE ALLIANCE OF WESTERN ENERGY CONSUMERS**

**June 6, 2018**

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**OPENING RATE CASE TESTIMONY OF DR. MARC M. HELLMAN**



**EXHIBIT LIST**

Exhibit AWEC/301: Qualification Statement of Dr. Marc Hellman

Confidential Exhibit AWEC/302: Budget Manual Instructions for 2016 and 2017

Exhibit AWEC/303: OLS Output Results for Comparable Company Analysis

Confidential Exhibit AWEC/304 PGE Benefits Ranking

Confidential Exhibit AWEC/305: PGE Incentive Program Examples

Exhibit AWEC/306: Average to Budget Incentives Percentage Payout

Exhibit AWEC/307: PGE Responses to Data Requests

Exhibit AWEC/308: Central Lincoln People's Utility Dist. v. Oregon Dept. of Energy, Marion County Cir. Ct. Case No. 16CV18269 (Aug. 9, 2017)

Exhibit AWEC/309: Excerpt of ODOE ESA PowerPoint

# I. INTRODUCTION AND SUMMARY

**Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.**

A. Dr. Marc Hellman. My business address is 2760 Eagle Eye Ave. NW, Salem, Oregon 97304.

**Q. PLEASE STATE YOUR OCCUPATION AND ON WHOSE BEHALF YOU ARE TESTIFYING.**

A. I am an independent consultant and an economist by training with significant experience in energy utility regulation. I am testifying on behalf of the Alliance of Western Energy Consumers ("AWEC").

**Q. PLEASE SUMMARIZE YOUR EDUCATION AND WORK EXPERIENCE.**

A. I have a Masters and PhD in Economics awarded by Claremont Graduate School and a Bachelor's degree in both Economics and Mathematics awarded by California State Polytechnic University, Pomona.

With regards to my work experience, I was employed for 38 years in various capacities by the Public Utility Commission of Oregon, with the last twenty years or so in a management capacity leading economists, accountants and financial analysts in the review of utility general rate filings and rate proposals, financing and affiliated interest applications, property sales, and mergers and acquisitions. I have also worked for Boeing Computer Services and the Bonneville Power Administration. More recently, I have also provided consulting services, with my most recent projects for the Commonwealth Utilities Corporation with headquarters in Saipan, the Smart Energy Alliance in a Nevada

Power general rate filing before the Public Utilities Commission of Nevada, and the South Dakota Intrastate Pipeline Company.

I provide a listing of my education and experience in Exhibit AWEC/301.

**Q. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY?**

A. The purpose of this testimony is to review Portland General Electric Company's ("PGE" or "Company") general rate case application, docketed as UE 335, with respect to FTE, wages and salaries, benefits, incentives, pension, and the energy supplier assessment.

**Q. PLEASE SUMMARIZE YOUR TESTIMONY.**

A. I recommend the Commission reduce PGE's wage-related costs related to personnel by an amount of $16,445,653. This recommendation is based on adjustments to projected FTE levels and wages and salaries associated with those levels. The reduction of FTE is from PGE's test-year amount of 2867.5 to 2700, which equals a reduction of 167.5 FTE. Using the PGE average dollars-per-FTE of $98,183, and multiplying that number by the 167.5 reduction in FTE, the dollar reduction in wages is $16,445,653.

With respect to medical benefits, I recommend a reduction in expense of $12,940,730. This reduction is based on taking the 2017 PGE actual benefits per FTE cost, reducing it by five percent, and then escalating that value by 6.5 percent for two years to derive a 2019 dollars per FTE value of $32,436. Including a reduction in FTE of 167.5 yields a total reduction in benefits cost of $12,940,730.

My incentives adjustment is $3,313,393. This amount recognizes that the PGE incentives are contingent on sufficient earnings and therefore I increase, including other adjustments, the disallowance that PGE has assumed. The adjustment reflects the fact that PGE does not always pay its incentives in the amount budgeted. PGE over the most recent six-year history on average has paid 91 percent of budgeted incentives for non-officers. Another adjustment reflects removing 100 percent of the Board compensation paid in stock, which acts as an incentive to the Board to increase PGE share price. Finally, my adjustment of $3,313,393 incorporates the derived incentive-per-FTE amount of $3,597 multiplied by the 167.5 reduction in FTE, totaling $602,498.

I recommend pension expense be reduced by $2,500,000, reflecting increases in the discount rate from when PGE prepared its testimony. My recommendation is based on a 30-basis point increase in the discount rate.

Finally, I recommend a disallowance of $2,068,281, which represents the amount PGE has included in the test year related to the Energy Supplier Assessment (“ESA”). This is based on my assessment that PGE acted imprudently in failing to join litigation challenging the ESA for the 2017-2019 fiscal biennium and the lack of evidence demonstrating that customers receive any benefits from the ESA.

**Q. DO YOU HAVE A SUMMARY TABLE DISPLAYING THESE RECOMMENDATIONS?**

A. Yes. Table 1, below, summarizes my recommendations.

**TABLE 1**

| Topic | Adjustment Amount |
|---|---:|
| FTE | $16,445,653 |
| Benefits | $12,940,730 |
| Incentives | $3,313,393 |
| Pensions | $2,500,000 |
| ESA | $2,068,281 |
| **Total** | $37,268,393 |

**Q. DO THE VALUES ABOVE REFLECT REVENUE REQUIREMENT VALUES?**

A. No. For the compensation-related adjustments, those values still need to be split between capital and expense in order to derive revenue requirement values. The revenue requirement impact of my adjustments is provided in Table 1 of the Opening Rate Case Testimony of Bradley G. Mullins, Exhibit AWEC/200, and in Mr. Mullins' revenue requirement calculations in Exhibit AWEC/201.

**Q. DO YOU HAVE ANY NON-REVENUE REQUIREMENT RECOMMENDATIONS?**

A. Yes. I recommend the Commission direct PGE to file a report with the Commission no later than six months following the Commission's final order in this docket. The report would investigate changing PGE's budgeting approach to dollars instead of FTEs as suggested in Exhibit PGE/400, Mersereau-Neitzke/17-18, along with providing historical data for all labor-related services inclusive of contracted-for and PGE labor resources.

## II. FTE

**Q. PLEASE DESCRIBE PGE'S FTE RECOMMENDATIONS.**

A. In PGE's testimony, Exhibit PGE/400, Mersereau-Neitzke, PGE provides a forecast of 2019 Test Year FTEs. The source data for Table 2, below, is from the PGE/400 testimony and is used to calculate an average wage per FTE.

**TABLE 2**

| PGE | FTE 2017 Actuals | FTE 2018 Budget | FTE 2019 Test Year | Wages 2017 Actuals | Wages 2018 Budget | Wages 2019 Test Year | Wages Per FTE 2017 Actuals | Wages Per FTE 2018 Budget | Wages Per FTE 2019 Test Year |
|---|---|---|---|---|---|---|---|---|---|
| Administrative & General | 372.1 | 402.9 | 389.4 | $73,980 | $79,464 | $77,984 | $198,818 | $197,230 | $200,267 |
| Information Technology | 304.3 | 332.8 | 306.7 | $26,678 | $25,548 | $26,881 | $87,670 | $76,767 | $87,646 |
| Customer Service | 464.5 | 451.9 | 455.1 | $7,240 | $8,309 | $8,609 | $15,587 | $18,387 | $18,917 |
| Generation | 548.7 | 558.8 | 562.2 | $54,307 | $54,192 | $56,639 | $98,974 | $96,979 | $100,745 |
| Transmission and Distribution | 1044.9 | 1153.0 | 1154.1 | $98,485 | $107,560 | $111,427 | $94,253 | $93,287 | $96,549 |
| Total | 2734.6 | 2899.4 | 2867.5 | $260,690 | $275,073 | $281,540 | $95,334 | $94,872 | $98,183 |

The average wage per FTE for 2019 is $98,183.

**Q. BEFORE GOING FURTHER, DOES PGE HAVE STRONG REGULATORY INCENTIVES TO CONTROL ITS REQUESTS FOR WAGE EXPENSE?**

A. No. The exception that clearly comes to mind is where there are standard regulatory practices of disallowances, such as there are with incentives. In that case, PGE does have the incentive to control costs as shareholders bear all (as with officers) or a portion (as with non-officers) of the costs.

However, with many of the areas of operation, PGE has the incentive to overstate its prospective costs. Once rates are established, absent some sharing mechanism without a dead-band, PGE then has the incentive to control its costs since every dollar of cost cutting goes to shareholders. When using historic test periods, without adjusting for known and measurable changes, the utility does have the incentive to control costs because of regulatory lag. When costs increase, the utility does not get to recover those costs on a prospective basis until they have been reflected in a rate case.

Also, with historic test periods, there is actual data from which to review. The utility has the incentive to ensure its costs are prudent as the Commission likely has the policy of removing costs from the test year that are not prudent.

**Q. I NOTICED THAT YOU HAVE DISCUSSED HISTORICAL TEST PERIODS, BUT THE OREGON PUC TYPICALLY USES A FUTURE TEST PERIOD. DOES A UTILITY HAVE AS STRONG AN INCENTIVE TO CONTROL ITS COSTS WITH A FUTURE TEST YEAR?**

A. I do not believe so. The reason is the lack of regulatory lag. The utility can project its costs and has the opportunity to recover those costs in full under a future test period as there is no regulatory lag.

**Q. IS THERE A DRAWBACK TO A FUTURE TEST PERIOD?**

A. Yes. Future test periods are typically forecasted in some fashion and there is discretion and a subjective element to the forecast. One could argue that the utility has the upper hand in this discretion as it has more information typically than do outside analysts, so there is asymmetric information. For example, the utility can identify all areas of operation where costs are increasing and leave it to the outside analyst to identify areas where costs are decreasing.

**Q. WHILE PERHAPS NOT HAVING A STRONG INCENTIVE, DOES A UTILITY HAVE THE INCENTIVE TO CONTROL ITS COSTS AT ALL UNDER A FUTURE TEST PERIOD FORMAT?**

A. Yes. Once a utility has its rates set, the utility has the incentive to control its costs. However, this incentive is diminished during a period of frequent rate case filings.

**Q. WHY IS THAT?**

A. A utility with frequent rate cases has the incentive to build up its costs during these rate cases, with future test periods. It is likely not a successful strategy to overstate future test year costs, have actual costs come in lower, and expect the regulator to not figure out that costs are consistently being forecasted too high. However, building up on an upward trending cost basis and having actual costs come in at those levels will establish a "high" level of costs that are recovered through rates. At some point, when the utility believes it will not need to file a rate case for a few years, the utility could control its costs and any cost savings would go to shareholders. Management in a utility may also want to build up a larger and larger company so as to justify higher compensation as well.

Again, in both historic and future test periods, the utility does have some incentive to control its costs. The discussion here posits that the incentive is stronger in a historic test year rate setting framework because of greater regulatory lag.

**Q. PLEASE DISCUSS YOUR ANALYSIS OF PGE'S FTE TESTIMONY AND RECOMMENDATIONS.**

A. In this Docket, as in UE 319, PGE again projects significant increases in FTE levels as compared to calendar year 2017. As noted in AWEC's (then ICNU) testimony in UE 319, having growth in employees faster than Company fundamentals in the long term is not sustainable, as it places upward pressures on rates.[1/]

From an economics perspective, the PGE case is curious. Traditional economics provides that capital and labor are substitutes. You can use a mix of capital and labor to produce products. When wages are relatively high, which they are in the United States, capital substitutes for labor such as using equipment to trim trees or read meters. For the last several years, however, PGE has made investments in both capital (information and technology investments for example) and labor (increases in FTE), leading to increases in

[1/] Docket No. UE 319, Exhibit ICNU/300, Mullins/10-11.

rates. Presumably, all else held equal, major investments in technology should lead to decreases in labor, but overall that has not been the case, as evidenced by PGE's general rate case filing, and this result raises questions about the prudence of PGE's capital spending.

**Q. WHAT IS THE PGE PROJECTED INCREASE IN LOADS AND CUSTOMERS FROM 2017 TO 2019?**

A. PGE's response to AWEC Data Request 93 includes the following total load and customer information from which that question can be answered.[2/]

| Year | Total Customers | Load | FTE |
|---|---|---|---|
| 2017 (Actual) | 874568 | 1601 | 2734.6 |
| 2019 (PGE Requested or Projected) | 895433 | 1587 | 2867.5 |
| Percentage Increase | 2.39 | -0.87 | 4.86 |

The last column is taken from FTE totals listed in Exhibit PGE/400, Mersereau-Neitzke/13. Notice that the requested number of FTE grows twice as fast as total customers. With respect to load, load is declining and yet FTEs grow significantly.

**Q. PGE HAS PROVIDED TESTIMONY THAT DISCUSSES CHANGES IN FTE AND THE FUNDAMENTAL CAUSES REQUIRING THOSE CHANGES. DO YOU FIND THAT TESTIMONY CONVINCING?**

A. No, not on a total-Company basis. PGE may be identifying trends in certain areas of the Company, but the key assumption in PGE's testimony is essentially that everything else not discussed in PGE's testimony relating to FTE and workload is being held constant.

[2/] Exhibit AWEC/307, Hellman/13-22.

**Q. WHAT DO YOU MEAN?**

A. One way to analyze the PGE FTE request is to review all the new position descriptions to see if the positions look necessary to handle the work requirements. But let us say that was done and all the requested positions look needed. That by itself does not mean that PGE's FTEs should increase by that amount. In mathematical terms, it would be deemed necessary but not sufficient.

**Q. WHY IS THAT?**

A. The information that is lacking from PGE's testimony is essentially a critical review of all PGE positions. This is because work load in some areas may not be needed, or as critical, or some positions could be combined to capture efficiencies in work product. Management should be expected to take this critical review to manage costs. Therefore, in my opinion, PGE has not satisfied its burden to demonstrate a need for its requested increase in FTEs.

For non-economically regulated companies, competitive pressures can drive a company to evaluate its labor needs in order to control costs so that its prices are competitive and also produce a reasonable return to shareholders. Regulated utilities such as PGE do not face such pressures.

**Q. DID YOU REVIEW THE BUDGETING REVIEW PROCESS TO SEE IF PGE HAD UNDERTAKEN A FULL REVIEW OF ITS FTE POSITIONS?**

A. I reviewed the Company's budget instruction manuals for 2017 and 2018, which are attached as Confidential Exhibit AWEC/302. The manual for the 2019 budget is not available as those are developed in the third quarter of 2018. In reviewing the manuals, they seemed designed more from an accounting perspective, ensuring common definitions and accounting recording across agencies.

**Q. DID YOU SEE ANYTHING IN THE BUDGET INSTRUCTION MANUALS ASKING FOR A REVIEW OF COST AND PROGRAMS TO IDENTIFY EFFICIENCIES OR REVIEW EXISTING PROGRAM LEVELS?**

A. No.

**Q. DID YOU CONDUCT ANY ANALYSIS TO DETERMINE OVERALL REASONABLENESS OF PGE FTE LEVELS?**

A. Yes. I noticed that in last year's ICNU testimony there was presented a comparison with Puget Sound Energy ("Puget") and what Puget's operating relationships implied for PGE.[3/] I also reviewed PGE's responsive testimony that viewed Puget as not a reasonable proxy for PGE, as Puget is a combined electric/natural gas utility. Given that discussion in UE 319, I analyzed FTE relationships using several other energy utilities.

**Q. PLEASE DESCRIBE THE APPROACH YOU UNDERTOOK.**

A. In PGE's cost of capital testimony, PGE identifies utility/energy companies of comparable risks. The list of companies is found on Exhibit PGE/1003, Hager-Liddle-Villadsen/3.

For the listed companies, I researched the following information: number of employees, number of customers, number of transmission line miles, and number of distribution line miles. I was able to find that information for many of the companies listed in PGE/1003, Hager-Liddle-Villadsen/3.

My next step was to estimate, using ordinary least squares regression, the relationship of number of company employees to the factors listed above. In addition, I

[3/] Docket No. UE 319, Exhibit ICNU/300, Mullins/11.

used a distribution line miles per customer as a possible explanatory variable, as a compact utility might have different labor needs than a utility with customers spread out. Table 3, below, provides the relevant data:

**TABLE 3**

| | Employees | Customers | Trans. Lines Miles | Distrib. Lines Miles | Distrib. Line Miles Per Customer |
|---|---|---|---|---|---|
| AEP Ohio | 1551 | 1472771 | 8195 | 45718 | 0.0310422 |
| AEP Texas | 1623 | 972853 | 8736 | 42691 | 0.0438823 |
| AEP Appalachian Power | 1986 | 1040204 | 7434 | 54284 | 0.0521859 |
| Indiana Michigan Power | 2368 | 587252 | 5240 | 20410 | 0.0347551 |
| Kentucky Power | 635 | 167708 | 1283 | 10080 | 0.0601045 |
| Public Service Company of Oklahoma | 1671 | 550000 | 3635 | 22260 | 0.0404727 |
| Southwestern Electric Power Company | 1716 | 534632 | 4103 | 25197 | 0.0471296 |
| Center Point Energy | 7727 | 2403340 | 3718 | 52639 | 0.0219024 |
| Idaho Power Company | 1964 | 547000 | 4857 | 27441 | 0.0501664 |
| Duke Energy | 28798 | 7483171 | 32300 | 268700 | 0.0359072 |
| OGE Energy | 2500 | 830057 | 5200 | 55500 | 0.0668629 |
| Ameren | 8500 | 3300000 | 4500 | 67500 | 0.0204545 |

**Q. HOW DID YOU PERFORM YOUR ANALYSIS OF THE INFORMATION IN THE TABLE ABOVE?**

A. I ran two ordinary least squares regression analyses, the output for which I have attached as Exhibit AWEC/303. The first regression used all the data in the above table. Using the relationships estimated using ordinary least squares, and applying them to PGE's number of customers, transmission line miles, distribution line miles and distribution line miles per customer, PGE would have 2,137 FTE.[4/] However, in this regression, none of

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[4/] Exhibit AWEC/303, Hellman/1.

the estimated coefficients are significant in "t value".[5/]

The second regression was identical in formulation to the first with the exception that I excluded the last variable, namely the distribution line miles per customer. Using this formulation, the number of PGE FTE would be 2,185, applying the estimated parameters to PGE's data.[6/] In the second regression, the coefficient to the first two variables—the intercept term and number of customers—is significant.

The results for both of the regressions are close to one another, being less than 50 FTE apart. I also note that the fitted PGE FTE values are several hundred FTE lower than PGE's current FTE level.

**Q. WHAT DO YOU CONCLUDE FROM THIS ANALYSIS?**

A. I conclude that the Commission should be very hesitant to approve rates based on a significant increase in PGE FTE levels.

**Q. DID YOU ALSO DEVELOP ANY SUGGESTED PGE FTE LEVELS BY LOOKING AT PGE'S RECENT CUSTOMER AND LOAD GROWTHS IDENTIFIED EARLIER IN YOUR TESTIMONY?**

A. Yes. The information is in Table 4, below.

**TABLE 4**

| Year | Total Customers | Load | FTE Using Average Growth | PGE Projected FTE |
|---|---|---|---|---|
| 2017 | 874568 | 1601 | 2734.6 | 2734.6 |
| 2019 | 895433 | 1587 | 2755.2 | 2867.5 |
| Percentage Increase | 2.39% | -0.87% | 0.76% | 4.86% |

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5/ A "t" statistic determines the existence of a significant correlation between variables and follows a "t" distribution. See page 791, "Introductory Econometrics", Wooldridge, Thomson, 2006.

6/ Exhibit AWEC/303, Hellman/2.

PGE had 2734.6 FTE in 2017. Using the average of the growth rate for total customers and load produces a 2019 FTE level of 2755.2. Even if you only used the customer growth rate of 2.39 percent by itself, the resulting FTE level is 2800, still significantly below PGE's FTE request of 2867.5. I show the last column on the right to display the growth in FTE PGE is requesting in this docket as a comparison.

**Q. SHOULD THE COMMISSION GIVE MUCH WEIGHT TO THE 2755 OR 2800 FTE VALUES USING THE MOST RECENT FTE AND CUSTOMER GROWTH RATE VALUES?**

A. No. The reason is that the 2017 value by itself reflects a major increase in number of FTE from prior years. If we do the same analysis looking at the growth in customers from 2016 to 2019, instead of 2017 to 2019, we get significantly different results.

**Q. PLEASE EXPLAIN.**

A. In 2016, the actual FTEs were 2581.3 and number of customers were 862,764.[7/] The percentage change in customers from 2016 to 2019 is 3.79%. If you increase the 2016 actual FTEs of 2581.3 by the 3.79% you get a 2019 FTE level of 2679. Table 5, below, displays this information.

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7/ Docket No. UE 319, PGE/400, Mersereau-Jaramillo/11; Exhibit AWEC/307, Hellman/20 (PGE Resp. to AWEC Data Request 93, Attach. 93-D).

**TABLE 5**

| | UE 319 2016 Actuals | UE 335 2017 Actuals | UE 319 2018 Test Year | UE 335 2018 Budget | UE 335 2019 Test Year |
|---|---|---|---|---|---|
| PGE FTEs | 2581.3 | 2734.5 | 2851.0 | 2899.4 | 2867.5 |
| Number of Customers | 862764 | | | | 895433 |
| Growth from 2019 to 2019 | | | | | 3.79% |
| FTE at Comparable Growth | | | | | 2679.0 |

Looking at the 2016 to 2019 growth rate in customers could support an FTE level of 2679.

**Q. BASED ON ALL OF YOUR ANALYSES ABOVE, WHAT IS YOUR RECOMMENDED FTE LEVEL THAT SHOULD BE USED IN THIS DOCKET?**

A. I recommend the Commission base rates on 2700 FTE. This represents a 167.5 reduction in the PGE UE 335 requested FTE level. This takes into account the discussion above by placing more weight on the longer-term relationship of customer growth and FTE.

**Q. HAS THE COMMISSION DISCUSSED THE MERITS OF USING A LONGER-TERM TREND OF FTE IN AN ORDER?**

A. Yes. In Docket UE 102, OPUC Staff had proposed using several years (1991 through 1999) to form a trend for establishing a recommended level of FTE. PGE opposed the Staff trending analysis as not being statistically well founded. The Commission in Order 99-033 adopted Staff's approach, however, stating that this approach was "likely to produce consistent reasonable figures. We adopt Staff's principle."[8/]

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8/ Re: Portland General Electric Company, Docket No. UE 102, Order No. 99-033, 1999 WL 135188 (Or.P.U.C.), 191 P.U.R.4th 87 at *56 (Jan. 27, 1999).

**Q. WHAT DOES THIS PROVIDE FOR AN ADJUSTMENT TO PGE'S 2019 WAGE EXPENSE LEVEL?**

A. Using PGE's 2019 wage and salary levels of $98,183 per FTE, and reducing the number of FTE by 167.5, yields an adjustment of $16,445,653.

## III. BENEFITS

**Q. PLEASE DISCUSS YOUR REVIEW OF BENEFITS.**

A. For the benefits analysis I focused on information provided by PGE in its testimony and accompanying exhibits, one of which is marked confidential. Benefits cost will also depend on number of FTE, so the first step is to derive a recommended benefit per FTE, and then apply that to the FTE levels I am recommending.

Using that information, I develop an adjustment for benefits expense for 2019. Table 6, below, shows this analysis for deriving a recommended benefits expense per FTE.

### TABLE 6

| | FTE[1] | | | Benefits[2] | | | Benefits Per FTE | | |
|---|---|---|---|---|---|---|---|---|---|
| | 2017 | 2018 | 2019 Test | 2017 | 2018 | 2019 | 2017 | 2018 | 2019 |
| PGE | Actuals | Budget | Year | Actuals | Budget | Test Year | Actuals | Budget | Test Year |
| Total | 2734.5 | 2899.4 | 2852.0[9/] | $82,318 | $96,502 | $100,519 | $30,103 | $33,283 | $35,245 |
| Percentage Change From Prior Year | | 6.03% | -1.10% | | 17.23% | 4.16% | | 10.56% | 5.89% |
| Value if increased by 6.5% | | | | | | | | $32,060 | $34,144 |

[1] PGE/400, Mersereau-Neitzke/12

[2] PGE/400, Mersereau-Neitzke/28

9/ In response to AWEC Data Request 66, PGE stated that it assumed 2852 FTE for medical benefits. For purposes of how I calculate the adjustment, the number of FTE PGE projects does not impact my adjustment. I use actual 2017 benefits per FTE cost, and escalate that to 2019 values, and then apply the cost per FTE to my recommended 2019 FTE levels.

**Q. DOES YOUR ANALYSIS BEGIN WITH DEVELOPING A 2017 BENEFITS PER FTE AMOUNT?**

A. Yes. That is the $30,103 value shown in the table above.

**Q. PLEASE EXPLAIN THE ROW TITLED, "VALUE IF INCREASED BY 6.5%."**

A. I included that line as Exhibit PGE/400, Mersereau-Neitzke/29, line 17, says that nationally the projected growth rate for medical costs is 6.5 percent. I use that national average to escalate the growth in actual 2017 PGE benefits cost to project 2018 and 2019 values.

**Q. WHAT DOES THIS IMPLY FOR AN ADJUSTMENT TO BENEFITS?**

A. PGE has a test year benefits amount of $100,519,000. If benefits are adjusted to $34,272, which is the 2017 actual value escalated two years at 6.5 percent, and you apply that average benefit level to my recommended FTE level of 2700, you get a 2019 Test Year benefits amount of $92,534,223. Subtracting $92,534,223 from $100,519,000 yields a reduction of benefits expense of $7,984,777. This adjustment is inclusive of all costs (such as administrative) for Total Benefits listed in Table 8, Exhibit PGE/400, Mersereau-Nietzke/28.

**Q. SO IS YOUR RECOMMENDED ADJUSTMENT THEN THE $7,984,777 VALUE?**

A. No. I have one more step in my derivation.

**Q. PLEASE EXPLAIN.**

A. In the beginning of Exhibit PGE/400, Mersereau-Nietzke/4, PGE discusses its total compensation philosophy which includes "the features and costs both among employee groups and against what other employers in our market provide to their employees."[10/] To better understand what other companies provide to their employees, PGE retained firms to do market studies comparing PGE to the industry with respect to benefits compensation.

**Q. PLEASE CONTINUE.**

A. PGE testimony includes Confidential Exhibit/402 that provides two separate studies ranking PGE compensation against other comparable companies. The studies show that PGE is well above average and is in fact one standard deviation above that average. I have included Confidential Exhibit AWEC/304, showing this result.

**Q. WHAT YEAR IS ANALYZED BY THE PGE-REQUESTED STUDIES?**

A. It appears that the studies are for 2017. That means that the 2017 actual level is above the average and should be adjusted downward.

**Q. WHAT DOWNWARD ADJUSTMENT DO YOU MAKE?**

A. I recommend making a five percent adjustment. The five percent value comes from looking at the results of the PGE confidential studies and conservatively inferring the amount PGE is above market. With the five percent adjustment downwards, that moves PGE much closer to market.

If we take the actual 2017 benefits per FTE, and reduce them by five percent, and then escalate those values by 6.5 percent annually, we get a 2019 Test-Year benefits per FTE amount of $32,436, shown in Table 7, below.

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[10/] Exhibit PGE/400, Mersereau-Nietzke/27.

**TABLE 7**

Benefits Per FTE

| 2017 Actual | 2017 Adjusted | 2018 at 6.5% | 2019 at 6.5% |
|---|---|---|---|
| $30,103 | $28,598 | $30,457 | $32,436 |

**Q. SO WHAT IS YOUR RECOMMENDATION WITH RESPECT TO BENEFITS?**

A. I recommend a reduction of $12,940,730 to benefits expense be applied to PGE's test year request of $100,519,000. That number is derived by applying the per-FTE medical benefits cost of $32,436 shown in the table above to my recommended FTE level of 2700, for a total 2019 benefits cost of $87,578,270.

## IV. INCENTIVES

**Q. PLEASE SUMMARIZE PGE'S REQUEST FOR INCENTIVES INCLUDED IN THE 2019 TEST YEAR.**

A. PGE included a value of $13,026,000 in its 2019 Test Year. This value is taken by calculating the estimated level of total 2019 incentives and then taking 50 percent of that value for all incentives except for PGE Officer incentives which PGE excluded 100 percent from the test year.

**Q. WHY DID PGE EXCLUDE A PORTION OF THE PROJECTED INCENTIVES FROM ITS 2019 TEST YEAR REQUEST?**

A. PGE states that they did so to reduce its overall revenue requirement request and that this is consistent with what PGE proposed in UE 319[11/].

[11/] Exhibit PGE/400, Mersereau-Neitzke/21-22.

**Q. ARE THE PERCENTAGES PGE EXCLUDED CONSISTENT WITH COMMISSION PRACTICE?**

A. Partially. PGE's 100 percent exclusion of officers' incentives is consistent with Commission practice. However, the 50 percent exclusion of the other incentives is not consistent with Commission practices.

**Q. WHY IS THAT?**

A. In its UE 319 testimony, Staff included a description of Commission policy with respect to incentives.

> For incentives, Commission policy traditionally disallows 100 percent of officers' bonuses, which are typically based on earnings. It is also Commission policy to disallow 75 percent of performance-based bonuses (because they are generally focused on increased earnings and, therefore, bring more benefit to shareholders) and disallow 50 percent of merit-based bonuses (because they equally benefit shareholders and ratepayers). Union bonuses are treated in the same manner as non-union bonuses.[12/]

Given that awarding the incentives is contingent on meeting an earnings threshold, PGE's exclusion of 50 percent of the incentives, and not some greater percentage perhaps up to 75 percent, is not appropriate.

**Q. DID YOU REVIEW PGE'S INCENTIVES TO SEE WHETHER ANY OF THE NON-OFFICER INCENTIVES SHOULD BE EXCLUDED AT THE 75 PERCENT LEVEL INSTEAD OF AT 50 PERCENT?**

A. Yes. In reviewing PGE's incentives policies for non-officers, which are provided in PGE's Workpapers, it appears that most of the incentives are dependent on PGE's earnings being sufficient as a trigger as to whether the incentive is provided by PGE. It also appears that whether an earnings level is sufficient is ultimately up to executive

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12/ Docket No. UE 319, Exhibit Staff/400, Gardner/35-36.

management. However, the incentives are typically awarded on performance in areas other than those tied directly to earnings. So while they are not "earnings" performance incentives, granting incentives is dependent on earnings. I have attached as Confidential Exhibit AWEC/305 two of PGE's incentives programs.

This contrasts with an incentive mechanism that is independent of earnings. For example, you could have an incentive awarded contingent solely on the number of at-fault customer complaints being below a threshold. Presumably it is this kind of incentive that would merit the 50 percent disallowance.

**Q. SO WHAT DO YOU CONCLUDE?**

A. I conclude that a modest further adjustment is warranted on this issue because earnings are a factor (and sometimes a dispositive factor) as to whether the incentive is paid out.

**Q. WHAT ADJUSTMENT DO YOU RECOMMEND?**

A. For this topic, and consistent with Commission practice, I recommend an adjustment between 50 and 75 percent. Specifically, I recommend 55 percent of the non-officer incentives be excluded because a value greater than 50 percent is warranted. While it is true that the incentives themselves are not directly tied to earnings, there has to be sufficient earnings to enable the incentives to be granted, so they are earnings-related. A movement of 50 to 55 percent seemed a reasonable and modest recognition of this fact.

**Q. IS THAT YOUR SOLE ADJUSTMENT APPROACH FOR INCENTIVES?**

A. No. There are other considerations in developing a recommended adjustment.

The first adjustment has to do with an overall adjustment to incentives levels. In looking over the history of budgeted versus actual incentives, I noticed that on average actual incentives paid out are less than budgeted incentives. In response to AWEC Data Request 49, PGE provided a history of budgeted and actual incentives for 2012 through 2017 inclusive.[13/] From that data, PGE's actual paid incentive was on average, for non-officer and Board incentives over the most recent six years, 2012 through 2017, inclusive, 91 percent of budgeted. A copy of my spreadsheet analysis is attached as Exhibit AWEC/306. I therefore took PGE's forecast for 2019 incentives and multiplied them by 91 percent to get an expected incentives paid estimate.

**Q. WHAT IS YOUR NEXT CONSIDERATION IN DEVELOPING YOUR ADJUSTMENT?**

A. PGE includes compensation to the Board in the form of stock. I removed all of this cost.

**Q. WHY?**

A. While this may be viewed as "compensation in the form of wages" and not incentives, I removed all the cost because as PGE's share price increases the value of the compensation increases. It is an incentive to the Board members to increase PGE's share price and therefore I consider it an incentive form of compensation. This is true even if the amount of stock paid to the Board member is independent of PGE's earnings. I should also note that in PGE's spreadsheet provided to AWEC in response to AWEC Data Request 67, PGE labels the payment as "Board of Directors Stock Incentives."[14/] Because stock payments to the Board are properly viewed as incentives based on earnings, they should be excluded from rates per established Commission policy.

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13/ Exhibit AWEC/307, Hellman/6-7.
14/ Exhibit AWEC/307, Hellman/11.

**Q. SO WHAT DO YOU DERIVE AS YOUR ADJUSTMENT?**

A. To derive my adjustment, I calculate the amount of expected incentives that is includable in rates per Commission policy. My analysis is based on using a 91 percent expected payout of budgeted incentives, removing officer incentives, Board member stock incentives, and removing 55 percent of non-officer incentives. This yields an incentive expense of $10,315,000. Since PGE has a 2019 Test Year expense of $13,026,000, my adjustment would be in the amount of $2,711,000 for the factors described above. But there is another factor to incorporate.

**Q. WHAT IS THE OTHER FACTOR TO INCORPORATE?**

A. PGE does not have to pay incentives on FTE that are not included in revenue requirements. Since I am making an FTE adjustment, there should be an incentive adjustment reflective of this. To do this calculation, we need to calculate a per-FTE incentive. The incentive per FTE using my incentive amount above of $10,315,000 is $3,597. This is calculated by taking the $10,315,000 and dividing it by PGE's FTE value of 2867.5. Taking the $3,597 and multiplying that by my recommended FTE level of 2700 equals $9,712,731. Subtracting $9,712,731 from $13,026,000 produces an adjustment equal to $3,313,393.

**Q. SO WHAT ARE YOUR RECOMMENDATIONS REGARDING INCENTIVES?**

A. I recommend an adjustment of $3,313,393.

## V. PENSIONS

**Q. PLEASE DISCUSS YOUR REVIEW OF PENSION EXPENSE.**

A. As noted in Exhibit PGE/400, Mersereau-Nietzke/34, PGE has identified $21.5 million in pension costs for 2019 with $14.5 million after capitalization. That same testimony on page 35 states that PGE used a discount rate of 3.64 percent. Further on in the testimony on that same page, PGE notes that interest rates will likely change and PGE will submit a revised discount rate in September.

**Q. DO YOU SUPPORT PGE'S REQUEST TO UPDATE THE DISCOUNT RATE IN SEPTEMBER?**

A. No. I believe it is preferable to determine the discount rate as we do most other matters being reviewed in the rate case. I know of no compelling argument as to why to single out this issue for updating. I understand that interest rates change over time, and that may benefit or harm consumers, but this is no different from many other assumptions in a rate case. The more inputs PGE is allowed to update over the course of its case, the less risk it has relative to other utilities, which would argue in favor of a reduction to its return on equity to account for this lower risk.

Instead, given PGE's and market consensus expectations that interest rates will continue to rise in 2018-2019, PGE should have reflected this expectation in its pension cost assumptions in its initial filing.

**Q. WHAT KIND OF SECURITIES ARE USED TO BASE THE DISCOUNT RATE UPON?**

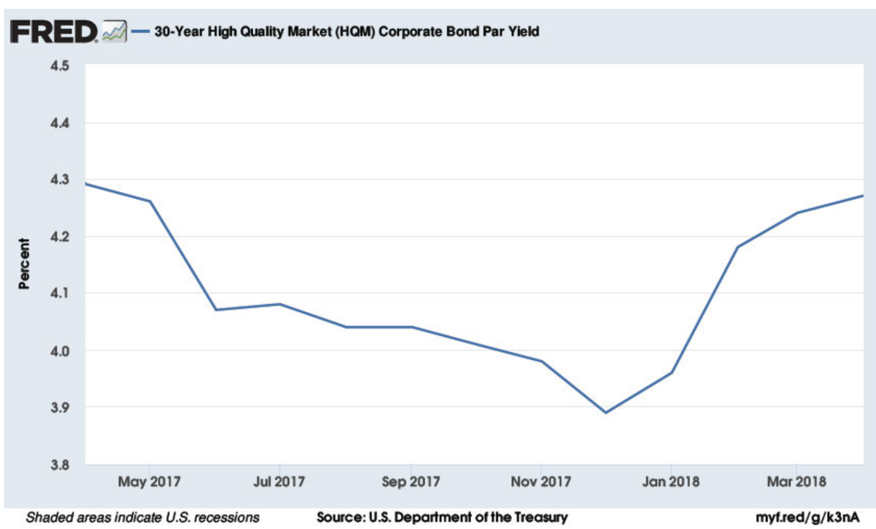
A. On Exhibit PGE/400, Mersereau-Nietzke/35, they state that high grade AA-rated corporate bonds are used.

**Q. DO PENSION COSTS VARY AS THE DISCOUNT RATE CHANGES?**

A. Yes. As the discount rate increases, pension costs decrease as future obligations are discounted at a higher rate. In response to AWEC Data Request 73, a copy of which is included within Exhibit AWEC/307, PGE states that a 10-basis point increase in the discount rate reduces pension expense by $860,000.

**Q. WHAT IS A HIGH-GRADE AA CORPORATE BOND RATE RETURN AT THIS TIME OF PREPARING YOUR TESTIMONY?**

A. According to the website https://fred.stlouisfed.org/series/HQMCB30YRP, the current bond rate is roughly 30 basis points higher, reflecting the increase in interest rates that has occurred over the last several months.




**Q. GIVEN THIS INCREASE IN CORPORATE BONDS, DO YOU RECOMMEND AN ADJUSTMENT TO FAS 87 PENSION EXPENSE?**

A. Yes. I recommend that pension expense be reduced by the impact of a 30-basis-point increase in the discount rate. My estimate of the change in FAS 87 expense is $2,500,000. This is based on both PGE's response to AWEC Data Request 73, as well as

PGE's response to Standard Data Request 60. PGE's response to that data request, included within Exhibit AWEC/307, provides that a 25-basis point increase in the discount rate would decrease FAS 87 expense by $2.1 million.

## VI. ENERGY SUPPLIER ASSESSMENT

**Q. WHAT IS THE ENERGY SUPPLIER ASSESSMENT ("ESA")?**

A. The ESA is a statutory fee on all "energy resource suppliers." ORS 469.421(8) provides the requirements of the ESA. Under this law, "energy resource suppliers" include "an electric utility…supplying, generating, transmitting or distributing electricity…in Oregon."[15] Thus, energy resource suppliers include all consumer- and investor-owned electric utilities, including PGE. The ESA provides a general revenue source for ODOE and also funds the Governor's Energy Policy Advisor.

**Q. HOW IS THE ESA AMOUNT DETERMINED?**

A. ORS 469.421(8)(b) sets forth the procedure for determining the assessment. ODOE's Director ("Director") determines the aggregate amount of the ESA that will be collected from energy suppliers to support the Energy Facility Siting Council and ODOE programs and activities. After making that determination, the Director is required to convene a public meeting with representatives of energy resource suppliers and other interested parties in order to provide these suppliers with a "full accounting" of both the projected revenue needed to fund each department program or activity and the projected allocation of moneys derived from the assessment imposed.

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[15] ORS 469.421(8)(i)(A).

**Q. DID ODOE FOLLOW THE PROPER PROCEDURE FOR ASSESSING THE ESA FOR THE 2015-2017 BUDGET?**

A. No. In 2016, certain energy suppliers challenged ODOE's process. Specifically, these energy suppliers, which did not include PGE, challenged whether the Director provided the required "full accounting." The Marion County Circuit Court ruled on summary judgment that there was "no genuine issue of material fact" that the Director did not provide a "full accounting" because "ODOE failed to specifically provide the representatives of energy resource suppliers and other interested parties the projected revenue needed to fund each department program or activity and the projected allocation of monies derived from the assessment imposed under this subsection to each department program or activity."[16/] ODOE is currently appealing the Court's ruling.

**Q. WHAT IS THE CALCULATED ESA FOR THE 2017-2019 BUDGET?**

A. The ODOE-calculated ESA is $13,119,539.[17/] PGE's share for the 2017-2018 fiscal year is $2,407,834.[18/] Both the total ESA, and the portion allocated to PGE, represents the latest in a series of significant ESA increases. Over the past five years, PGE's ESA has increased by 75%.[19/]

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[16/] Exh. AWEC/308, Hellman/7 (Central Lincoln People's Utility Dist. v. Oregon Dept. of Energy, Marion County Cir. Ct. Case No. 16CV18269 (Aug. 9, 2017)).

[17/] Exh. AWEC/309 ("ARB ESA" column).

[18/] Exh. AWEC/307, Hellman/1(PGE Resp. to ICNU DR 012). Certain data request in this exhibit are labeled "ICNU" because AWEC changed its name from the Industrial Customers of Northwest Utilities during the discovery phase of this proceeding.

[19/] Id. at 5 (PGE Resp. to AWEC DR 038, Attach. 038-A).

**Q. DID ODOE PROVIDE A "FULL ACCOUNTING" TO ENERGY SUPPLIERS TO JUSTIFY THE ESA FOR THE 2017-2019 BUDGET?**

A. No. ODOE's accounting for ESA funds consisted of a single page spreadsheet in a larger PowerPoint presentation that provides lump sum numbers in generalized categories.[20/] This appears to be the complete explanation ODOE provided for its use of the ESA for the current fiscal biennium. As can be seen, no specific information is provided as to why the collection or application of the ESA funding categories is appropriate or necessary. For instance, over $4 million of the ESA is allocated simply to the "Director's Office" without any further explanation.

**Q. DID ENERGY SUPPLIERS CHALLENGE THEIR ASSESSMENTS FOR THE 2017-2018 BUDGET YEAR BASED ON GROUNDS SIMILAR TO THOSE IN THE 2016 LITIGATION?**

A. Yes. A much larger group challenged their assessments for this most recent fiscal year. This action has been stayed pending the outcome of the appellate process for the 2016 litigation on the basis that the Court's ruling would be the same. Again, PGE did not join this litigation despite the high likelihood of success given the Court's prior ruling. In fact, only one investor-owned utility joined this litigation – Cascade Natural Gas.

**Q. DOES PGE RECOVER ITS ESA FROM CUSTOMERS?**

A. Yes, PGE has included $2,068,281 in 2019 test year rates.[21/]

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20/ Exh. AWEC/309. The full PowerPoint is available at: http://www.oregon.gov/energy/About-Us/Documents/2016%20ODOE%20Budget%20Webinar.pdf.

21/ Exh. AWEC/307, Hellman/1 (PGE Resp. to ICNU DR 012).

**Q. HAS PGE EXPLAINED WHY IT DID NOT JOIN THE LITIGATION OVER THE 2017-2018 ESA?**

A. Yes. In response to ICNU Data Request 13, PGE explained it intended to support the appeal of the 2016-2017 ESA, but did not join the lawsuit over the 2017-2018 ESA because resolution of this litigation "will have no additional effect on the legitimacy or legality of the ESA."[22/]

**Q. IS THIS A SATISFACTORY EXPLANATION?**

A. No. PGE's response entirely ignores the primary purpose of joining the 2017-2018 litigation, which is to obtain a refund of the ESA for this fiscal year. While I am not a lawyer, AWEC's attorneys inform me that only the named plaintiffs in the litigation will be entitled to such a refund if the litigation is successful.[23/] Thus, by not joining the 2017-2018 litigation, PGE failed to act in the best interests of its customers who historically have been responsible for paying the ESA.

**Q. HAS PGE RECEIVED AN INVOICE FOR THE 2018-2019 ESA?**

A. Yes. PGE owes $2,412,208.[24/]

**Q. COULD PGE STILL JOIN A LAWSUIT CHALLENGING THE 2018-2019 ESA?**

A. Yes, but PGE has thus far not indicated that it will. Since the ESA is established for a fiscal biennium, the basis for the 2018-2019 ESA is identical to that for the 2017-2018

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22/ Id. at 2 (PGE Resp. to ICNU DR 013).

23/ Oregon's Administrative Procedure Act imposes a 60-day period for filing challenges to agency decisions other than contested cases. ORS 183.484(2). Oregon courts have held that this statute provides the sole means for challenging such agency actions. Mendieta v. Division of State Lands, 148 Or. App. 586 (1998). Therefore, were PGE to wait to see whether the litigation is successful and then attempt to obtain a refund for itself based on issue preclusion or a similar legal theory, this action likely would fail.

24/ Exh. AWEC/307, Hellman/23-25 (PGE Resp. to AWEC DR 137, Attach. 137-A).

ESA. If PGE chose not to join the litigation for the 2017-2018 ESA, it would be a change in PGE's behavior were it now to join a lawsuit over the 2018-2019 ESA.

**Q. WHAT DO YOU RECOMMEND?**

A. I recommend that the Commission disallow the $2,068,281 PGE has included in its rate case for the ESA. I make this recommendation on two grounds.

First, and primarily, PGE acted imprudently and against its customers' interests in not joining the 2017-2018 ESA litigation. This litigation represented the only path for PGE to obtain a refund of its ESA for this fiscal year and was highly likely to succeed based on the Court's ruling on the 2016-2017 ESA. Moreover, because the litigation is being funded by a large group of energy suppliers, this was a low-cost, low-risk opportunity for the Company. PGE will again lose out on the opportunity to obtain a refund of its ESA if, as expected, it fails to join the lawsuit over the 2018-2019 ESA.

Second, there is no evidence in the record to show PGE challenged or sought greater detail in the ESA activities and, therefore, PGE has not demonstrated how customers benefit in any way from the ESA. As noted above, ODOE's "full accounting" of the ESA for the 2017-2019 biennium consisted of a single page in a presentation that merely assigns dollars to various departments within the agency without even a cursory explanation of how those dollars are being used and why they are necessary. PGE's ESA is funding ODOE programs that are described simply as "Public Schools," "Transportation," "Planning, Economics, and Other," and "Director's Office." As the lawsuits demonstrate, companies funding the ESA, such as PGE, do not know the specifics as to how this money is being used (hence the reason for the lawsuits against the ESA), so PGE cannot show that this money is being used to benefit customers.

## VII. NON-REVENUE REQUIREMENT ISSUE AND RECOMMENDATION

**Q. DO YOU HAVE ANY NON-REVENUE REQUIREMENT ISSUE TO DISCUSS?**

A. Yes. In Exhibit PGE/400, Mersereau-Nietzke/17-18, they highlight that PGE is considering changing the way PGE budgets for its labor-related activities. The testimony on PGE/400, Mersereau-Nietzke/18, lines 1 and 2 state that PGE should "focus on labor costs rather than FTEs." I think there is merit to this concept not only for PGE's internal purposes but also for a rate case setting. Focusing on budgets instead of FTEs in a rate case essentially captures in my view what a rate case is.

**Q. HOW IS THAT?**

A. While I recommend PGE revenue requirements be established using a 2700 FTE level, this is to identify an adjustment that is consistent with how PGE has presented its case. However, PGE is free to choose whatever level of FTEs it thinks best. The Commission sets rates, not the actual number of FTE the Company should have, and PGE is responsible for managing the Company.

Focusing on budgets would allow for a more holistic, higher-level view of labor cost where we look at trends in costs in relation to overall workload and fundamental factors. As I noted in my testimony, it is not possible to review every single Company position and decide whether it is warranted or not.

I also agree with the sentiment expressed in its testimony that PGE should focus on hiring the right mix of employees and not be as concerned on FTE count.

**Q. WHAT DO YOU RECOMMEND?**

A. I recommend the Commission direct PGE to file a report with the Commission no later than six months following the Commission's final order in this docket. The report would investigate changing PGE's budgeting approach to dollars instead of FTEs as suggested in Exhibit PGE/400, Mersereau-Neitzke/17-18, along with providing historical data for all labor-related services inclusive of contracted-for and PGE labor resources.

**Q. DOES THAT CONCLUDE YOUR TESTIMONY?**

A. Yes.

**BEFORE THE PUBLIC UTILITY COMMISSION**

**OF OREGON**

**UE 335**

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|---|---|
| In the Matter of | ) |
| | ) |
| PORTLAND GENERAL ELECTRIC COMPANY, | ) |
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**EXHIBIT NO. AWEC/301**

**QUALIFICATION STATEMENT OF DR. MARC M. HELLMAN**

Marc Hellman, PhD.

Witness on Behalf of Alliance of Western Energy Consumers

2760 Eagle Eye Ave NW

Salem, Oregon 97304

## *WORK EXPERIENCE*

Dr. Hellman, of MH Energy Economics LLC, has nearly 40 years' experience in the field of regulatory economics and has consulted for telecommunications and electric industries as well as Boeing Computer Services. Beginning in 1979, Dr. Hellman was employed by the Public Utility Commission of Oregon (OPUC) in various capacities and has specialized in cost-based pricing and revenue requirements analysis for electric, natural gas, telecommunications and water industries. Up to September 2017, Dr. Hellman was Administrator of the Energy Rates, Finance and Audit Division and managed over a dozen expert staff of economists, accountants, and financial analysts dedicated to conducting a wide range of research on such matters including: utility cost of capital, utility financing applications, rate spread and rate design, utility merger and acquisitions, as well as conducting utility audits and benchmarking studies. Most recently in 2013, Dr. Hellman was appointed to advise the Oregon Governor's Office on the Columbia River Treaty review. Dr. Hellman received his PhD in Economics from Claremont Graduate School in 1983, and for several years beginning in 2008, was an instructor at Oregon State University teaching micro and macroeconomics as well as energy economics. Dr. Hellman has also recently provided consulting services for the Commonwealth Utilities Corporation with headquarters in Saipan, the Smart Energy Alliance in a Nevada Power general rate filing before the Nevada Commission, and the South Dakota Intrastate Pipeline Company.

*Major Regulatory Studies and Reports*

*Public Utility Commission of Oregon,* – chaired the water industry stakeholder workgroup and led discussions reviewing in total, both in scope of regulation and funding, the Commission Water Regulation Program, with the production of the report titled, "Review of the Oregon Public Utility Commission's Water Program," August 2002.

*Public Utility Commission of Oregon,* – authored major electric industry restructuring testimony presented before the Oregon Legislature, July 1997.

*Public Utility Commission of Oregon,* – led and directed Commission staff in reviews of several utility mergers and acquisitions including ScottishPower acquisition of PacifiCorp and Mid American holdings acquisition of PacifiCorp.

*Public Utility Commission of Oregon,* – led the first known study establishing estimates of unbundled network elements, memorialized in the report titled, "Telecommunications Building Blocks, Cost Report," July 1993.

*Public Utility Commission of Oregon,* – designed policies to address ratemaking treatment for research and development activities by Advanced Technologies, a fully owned subsidiary of US West, "Alternative Regulatory Policies for Telecommunications Utilities' Research and Development Costs," May 1992.

*Public Utility Commission of Oregon,* – analyzed and scored many alternative ratemaking mechanisms geared to incent electric utilities to acquire cost-effective conservation, "Investigation into Electric Utility Incentives for Acquisition of Conservation Resources," August 1991.

*Public Utility Commission of Oregon,* – as a precursor to integrated least cost planning, authored the report titled, "The 1989 Update to a Report on the PGE and PP&L Energy Surplus: Its Size, Duration, and Management," September 1988, as well as, "A Report on the PGE and PP&L Energy Surplus: Its Size, Duration, and Management," September 1989.

*Expert Witness Testimony*

*Alliance of Western Energy Consumers (Washington Utilities and Transportation Commission Docket UE 170970),* – testimony in support of Hydro One acquisition of Avista with a focus on commitments relating to large electric energy users. 2018

*Smart Energy Alliance (Nevada PUC Docket 17-06003 and17-06004),* residential net metering rates and rate spread for direct access customers. 2017

*South Dakota Intrastate Pipeline Company (South Dakota Public Utilities Commission),* – management fee, rate proposal for pipeline decommissioning, rate of return. 2017

*Public Utility Commission of Oregon (Bonneville Power Administration Docket REP-12),* – select panel testimony in support of a $2 billion settlement of statutory rights to low-cost federal power. 2011

*Public Utility Commission of Oregon (Bonneville Power Administration Docket WP-10),* – analysis of statutory test that limits access to low-cost federal power by residential and small-farm customers of investor-owned utilities. 2009

*Public Utility Commission of Oregon (Bonneville Power Administration Docket WP-07S),* – analysis of rights to low-cost federal power by residential and small-farm customers of investor-owned utilities. 2008

*Public Utility Commission of Oregon (Docket UM 1050),* – analysis of interjurisdictional cost allocation methods applicable to PacifiCorp. Docket was culmination of multi-year collaborative effort among the states of Washington, Idaho, Wyoming, Utah and Oregon to reach an agreed to allocations method. 2004

*Public Utility Commission of Oregon (Docket UE 88),* – analysis of alternative decoupling mechanisms designed to break the link between utility kWh sales and utility profits applicable to PacifiCorp. 1994

*Public Utility Commission of Oregon (Docket UE 79),* – ratemaking analysis of Portland General Electric wholesale power sales relating to the WNP #3 Settlement. 1990

*Public Utility Commission of Oregon (Bonneville Power Administration Docket WP-87),* – analysis of rights to low-cost federal power by residential and small-farm customers of investor-owned utilities. 1987

*Public Utility Commission of Oregon (Federal Energy Regulatory Commission Docket ER 82-2011-003),* – economics of nonfirm energy production in the Pacific Northwest and pricing of such power. 1984

*Public Utility Commission of Oregon (Bonneville Power Administration Docket WP-83),* – analysis of rights to low-cost federal power by residential and small-farm customers of investor-owned utilities, value of Direct Service Industry reserves, estimates of the Pacific Northwest Region long run incremental cost of wholesale power.

*Telecommunications*

- *Public Utility Commission of Oregon* – "The Status of Competition and Regulation in the Telecommunications Industry," – separate studies published roughly each year beginning in 2001.
- *Public Utility Commission of Oregon (Docket UM 351, Phase II),* – general pricing and unbundling policies for telecommunications retail services and unbundled network elements – 1995.
- *Public Utility Commission of Oregon (Docket UM 351),* – generic investigation to develop long run incremental cost of unbundled network elements – 1993.
- *Public Utility Commission of Oregon (UM 295),* – ratemaking policies for telecommunications research and development activities – 1992.
- *Public Utility Commission of Oregon (UT 80),* – alternative form of regulation review and proposal for US West – 1991.
- *Public Utility Commission of Oregon (US WEST Docket UT 85),* – broad pricing policy – 1989.
- *Public Utility Commission of Oregon (PNB Docket UF 3565),* – telecommunications pricing issues, review of price elasticity studies, Western Electric Adjustment – 1980.

## *EDUCATION*

CLAREMONT GRADUATE SCHOOL, CLAREMONT, CALIFORNIA – MA, 1980, PhD, 1983

- Specialization in Optimization Theory/Microeconomic Theory/Monetary Economics.

CALIFORNIA STATE POLYTECHNIC UNIVERSITY OF POMONA -- BS, 1977

- Major in Mathematics and Economics.

## *OTHER*

- Graduate of 1997 Leadership Oregon Program. Each year, from all state employees, 20 to 30 future government leaders are selected to participate in LOP to learn about other state agencies and benefit from executive training.

- Member, American Economic Association

- Economics at Oregon State University

## *PUBLICATIONS*

*The Economics of a Surplus in Electrical Generating Capability: The Pacific Northwest,"* - Public Utilities Fortnightly, January 5, 1984, pages 45-47.

*Load Curve Responsiveness to Weather and the Cost Effectiveness of Conservation,"* - Public Utilities Fortnightly, September 30, 1982, page 51.

FORMAL TESTIMONY OFFERED IN THE FOLLOWING PROCEEDINGS:

| Cause | Agency | Year | Company | Topics |
|---|---|---|---|---|
| R-48 | OPUC | 1980 | Generic-Electric | Conservation potential from electric rate design |
| UF 3565 | OPUC | 1980 | PNB | Telecommunication pricing issues, review of elasticity studies, Western Electric Adjustment |
| UF 3753 | OPUC | 1982 | CPN | LRIC methodology, electric rate spread and rate design |
| UF 3779 | OPUC | 1982 | PP&L | LRIC and electric rate spread, and rate design |
| UF 3900 | OPUC | 1983 | PP&L | LRIC and electric rate spread, and rate design |
| WP 83 | BPA | 1983 | BPA | LRIC methodology and value of DSI energy and capacity reserves |
| AR 112 | OPUC | 1984 | Generic-Electric | Electric LRIC methodology and rate spread and rate design policy |
| ER 82-2011-003 | FERC | 1984 | BPA | Economics of nonfirm electric energy sales to the Pacific Southwest |
| UE 44 | OPUC | 1985 | Generic-Electric | Electric rate spread and rate design, LRIC methodology |
| UE 47/48 | OPUC | 1986 | PGE | Electric rate spread and rate design, valuation of WNP #3 settlement agreement |
| VI-86-OP-01 | BPA | 1986 | BPA | Review of BPA proposed Variable Industrial Power Rate |
| UE 58 | OPUC | 1987 | PP&L | Electric rate spread and rate design |
| UE 70 | OPUC | 1987 | PP&L | LRIC methodology and electric rate spread and rate design |
| WP 87 | BPA | 1987 | BPA | 7(b)(2) rate test |
| UT 85 | OPUC | 1989 | USWC | Telecommunications rate design policies |

| Cause | Agency | Year | Company | Topics |
|---|---|---|---|---|
| UT 80 | OPUC | 1991 | USWC | Telecommunications alternative form of regulation summary witness and productivity estimation |
| UM 295 | OPUC | 1992 | Generic-Telecommunications | Ratemaking policy for telecommunications research and development activities |
| UE 88 | OPUC | 1994 | PGE | Decoupling mechanism design to break link between kWh sales and utility profits |
| UM 351, Phase II | OPUC | 1995 | Generic-Telecommunications | General pricing and unbundling policies of telecommunications functionalities |
| UM 1050 | OPUC | 2004 | PacifiCorp | Interjurisdictional cost allocation methods |
| WP-07S | OPUC | 2008 | BPA | 7(b)(2) rate test, retroactive ratemaking |
| WP-10 | OPUC | 2009 | BPA | 7(b)(2) rate test |
| REP-12 | OPUC | 2011 | BPA | Long-term residential exchange settlement |
| Docket No. 17-06003 and 17-06004 | Nevada PUC | 2017 | Smart Energy Alliance | Residential net metering rates and rate design for direct access customers |
| Docket No. NG17-009 | South Dakota PUC | 2017 | South Dakota Intrastate Pipeline Company | Rate of Return, Decommissioning policy, and management fee |
| Docket No. U-170970 | Washington UTC | 2018 | Alliance of Western Energy Consumers | Merger rate credit design, merger benefits, larger industrial conservation option |

**BEFORE THE PUBLIC UTILITY COMMISSION**

**OF OREGON**

**UE 335**

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| PORTLAND GENERAL ELECTRIC COMPANY, | ) |
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| Request for a General Rate Revision. | ) |

**CONFIDENTIAL EXHIBIT NO. AWEC/302**

**BUDGET MANUAL INSTRUCTIONS FOR 2016 AND 2017**

**(REDACTED VERSION)**

Exhibit AWEC/302 contains Protected Information and has been redacted in its entirety in accordance with Order No 18-047.

**BEFORE THE PUBLIC UTILITY COMMISSION**

**OF OREGON**

**UE 335**

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| In the Matter of | ) |
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| PORTLAND GENERAL ELECTRIC COMPANY, | ) |
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# EXHIBIT NO. AWEC/303

## OLS OUTPUT RESULTS FOR COMPARABLE COMPANY ANALYSIS

SUMMARY OUTPUT

| *Regression Statistics* | |
|---|---|
| Multiple R | 0.986937168 |
| R Square | 0.974044973 |
| Adjusted R Square | 0.959213529 |
| Standard Error | 1589.788311 |
| Observations | 12 |

ANOVA

| | *df* | *SS* | *MS* | *F* | *Significance F* |
|---|---|---|---|---|---|
| Regression | 4 | 663948152.8 | 165987038.2 | 65.67431882 | 1.24203E-05 |
| Residual | 7 | 17691988.11 | 2527426.872 | | |
| Total | 11 | 681640140.9 | | | |

| | *Coefficients* | *Standard Error* | *t Stat* | *P-value* | *Lower 95%* | *Upper 95%* | *Lower 95.0%* | *Upper 95.0%* |
|---|---|---|---|---|---|---|---|---|
| Intercept | -1378.485082 | 5205.539924 | -0.264811163 | 0.798783105 | -13687.63103 | 10930.66086 | -13687.63103 | 10930.66086 |
| X Variable 1 | 0.002208603 | 0.003077084 | 0.717758282 | 0.496155496 | -0.005067546 | 0.009484751 | -0.005067546 | 0.009484751 |
| X Variable 2 | -0.117113965 | 0.418563681 | -0.279799636 | 0.787718666 | -1.106859797 | 0.872631866 | -1.106859797 | 0.872631866 |
| X Variable 3 | 0.061751792 | 0.125909188 | 0.490447067 | 0.638816222 | -0.235976127 | 0.359479711 | -0.235976127 | 0.359479711 |
| X Variable 4 | 2659.030867 | 108509.0929 | 0.024505143 | 0.981133617 | -253924.2018 | 259242.2635 | -253924.2018 | 259242.2635 |

This regression looks at all the companies.
Variable 1 is customers
Variable 2 is Transmission line miles
Variable 3 is Distribution line miles
Variable 4 is distribution line miles per customer

| | Employees | Customers | Transmission Lines Miles | Distribution Lines Miles | Line Miles per Customer |
|---|---|---|---|---|---|
| Portland General Electric | 2752 | 862764 | 1200 | 27000 | 0.031294769 |

Portland General Electric estimated employees 2137.0

SUMMARY OUTPUT

| *Regression Statistics* | |
|---|---|
| Multiple R | 0.98693604 |
| R Square | 0.974042747 |
| Adjusted R Square | 0.964308777 |
| Standard Error | 1487.174579 |
| Observations | 12 |

ANOVA

| | *df* | *SS* | *MS* | *F* | *Significance F* |
|---|---|---|---|---|---|
| Regression | 3 | 663946635.1 | 221315545 | 100.0663394 | 1.10555E-06 |
| Residual | 8 | 17693505.83 | 2211688.229 | | |
| Total | 11 | 681640140.9 | | | |

| | *Coefficients* | *Standard Error* | *t Stat* | *P-value* | *Lower 95%* | *Upper 95%* | *Lower 95.0%* | *Upper 95.0%* |
|---|---|---|---|---|---|---|---|---|
| Intercept | -1251.944751 | 615.2219095 | -2.034948255 | 0.076269429 | -2670.649018 | 166.7595163 | -2670.649018 | 166.7595163 |
| X Variable 1 | 0.002137269 | 0.000932975 | 2.290811025 | 0.051199994 | -1.41748E-05 | 0.004288713 | -1.41748E-05 | 0.004288713 |
| X Variable 2 | -0.124897834 | 0.254984634 | -0.489824946 | 0.63740676 | -0.712893454 | 0.463097785 | -0.712893454 | 0.463097785 |
| X Variable 3 | 0.064549305 | 0.049681028 | 1.299274742 | 0.230040508 | -0.050015351 | 0.179113961 | -0.050015351 | 0.179113961 |

This regression looks at all the companies.
Variable 1 is customers
Variable 2 is Transmission line miles
Variable 3 is Distribution line miles

| | Employees | Customers | Transmission Lines Miles | Distribution Lines Miles |
|---|---|---|---|---|
| Portland General Electric | 2752 | 862764 | 1200 | 27000 |

| | |
|---|---|
| Portland General Electric estimated employees | 2185.0 |

**BEFORE THE PUBLIC UTILITY COMMISSION**

**OF OREGON**

**UE 335**

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| In the Matter of | ) |
| | ) |
| PORTLAND GENERAL ELECTRIC COMPANY, | ) |
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| | ) |
| Request for a General Rate Revision. | ) |
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**CONFIDENTIAL EXHIBIT NO. AWEC/304**

**PGE BENEFITS RANKING**

**(REDACTED VERSION)**

Exhibit AWEC/304 contains Protected Information and has been redacted in its entirety in accordance with Order No. 18-047.

**BEFORE THE PUBLIC UTILITY COMMISSION**

**OF OREGON**

**UE 335**

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**CONFIDENTIAL EXHIBIT NO. AWEC/305**

**PGE INCENTIVE PROGRAM EXAMPLES**

**(REDACTED VERSION)**

Exhibit AWEC/305 contains Protected Information and has been redacted in its entirety in accordance with Order No. 18-047.

**BEFORE THE PUBLIC UTILITY COMMISSION**

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| PORTLAND GENERAL ELECTRIC COMPANY, | ) |
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**EXHIBIT NO. AWEC/306**

**AVERAGE TO BUDGET INCENTIVES PERCENTAGES PAYOUT**

**Total Compensation Summary ($000)**

| Incentive Compensation | | | 2012 Budget[d,f] | 2012 Actual | 2013 Budget | 2013 Actual | 2014 Budget | 2014 Actual | 2015 Budget | 2015 Actual | 2016 Budget | 2016 Actual | 2017 Budget | 2017 Actuals | Non Officer 6-Yr Budget | Non Officer 6-Yr Actual | Percentage Payout |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Boardman (PGE share) | | 123 | 120 | 160 | 153 | 272 | 230 | 271 | 191 | - | 2 | - | - | | | |
| | Coyote Springs (PGE Share) | | 277 | 408 | 288 | 191 | 320 | 251 | 328 | 466 | 296 | 438 | 359 | 39 | | | |
| | Port Westward | | 437 | 443 | 428 | 510 | 483 | 642 | 559 | 678 | 547 | 601 | 588 | 675 | | | |
| | Carty PIC | | - | - | - | - | - | - | - | - | 502 | 514 | 511 | 648 | | | |
| | Pelton PIC (PGE Share) | | 8 | 10 | 16 | 13 | 19 | 18 | 18 | 17 | 20 | 18 | 16 | 29 | | | |
| | Biglow | | 21 | 29 | 45 | 34 | 42 | 54 | 43 | 21 | 39 | 65 | 36 | 52 | | | |
| | Tucannon | | - | - | - | - | - | - | 37 | 24 | 19 | 12 | 31 | 22 | | | |
| labor loadings | PGE PIC | | 7,990 | 6,888 | 9,494 | 7,068 | 11,515 | 10,715 | 11,910 | 8,651 | 12,611 | 9,499 | 16,413 | 15,337 | | | |
| | Total Gross PIC | | 8,856 | 7,899 | 10,432 | 7,968 | 12,650 | 11,910 | 13,166 | 10,047 | 14,034 | 11,149 | 17,953 | 16,802 | | | |
| | PIC = Performance Incentive Compensation | | | | | | | | | | | | | | | | |
| | | | | | | | | | | | | | | | | | |
| | Boardman ACI (PGE share) | | 37 | 45 | 38 | 22 | 55 | 15 | 59 | 35 | - | 14 | - | 3 | | | |
| | Pelton ACI | | 19 | 14 | 19 | 18 | 22 | 18 | 19 | 17 | 19 | 15 | 20 | 20 | | | |
| | Wholesale Marketing | | 1,306 | 1,200 | 1,211 | 1,275 | 1,386 | 1,285 | 1,272 | 1,388 | 1,370 | 1,122 | 1,420 | 1,420 | | | |
| | PGE ACI | | 2,658 | 2,304 | 2,641 | 2,540 | 2,756 | 3,052 | 2,921 | 2,616 | 2,889 | 2,321 | 2,717 | 3,137 | | | |
| | Officer ACI | | 1,051 | 1,637 | 1,946 | 1,326 | 2,142 | 2,250 | 2,272 | 2,348 | 2,380 | 1,976 | 2,391 | 2,799 | | | |
| | **Total ACI** | | **5,071** | **5,200** | **5,855** | **5,181** | **6,361** | **6,620** | **6,542** | **6,404** | **6,659** | **5,448** | **6,548** | **7,379** | | | |
| | PGE Stock Incentives | | 1,068 | 1,228 | 1,337 | 1,315 | 1,354 | 1,450 | 1,426 | 1,224 | 1,468 | 1,376 | 1,791 | 1,657 | | | |
| | Officer Stock Incentives | | 1,996 | 2,473 | 2,748 | 2,446 | 3,500 | 3,721 | 4,176 | 4,049 | 4,739 | 4,228 | 4,694 | 4,157 | | | |
| | Board of Director Stock Incentives | | 486 | 567 | 547 | 562 | 623 | 746 | 750 | 750 | 750 | 823 | 850 | 854 | | | |
| | **Total Stock Incentive Plan** | | **3,550** | **4,269** | **4,632** | **4,323** | **5,476** | **5,918** | **6,352** | **6,023** | **6,957** | **6,427** | **7,335** | **6,668** | | | |
| labor loadings | Notable Achievement Awards | | 259 | 409 | 257 | 638 | 257 | 567 | 257 | 770 | 307 | 1,427 | 662 | 933 | | | |
| | Miscellaneous Awards | | 8 | 39 | - | 28 | - | 240 | - | 266 | - | 75 | - | 282 | | | |
| | **Total Notables & Misc.** | | **267** | **448** | **257** | **666** | **257** | **807** | **257** | **1,036** | **307** | **1,502** | **662** | **1,215** | | | |
| | **Total Gross Incentives Minus Officer and Board Incentives** | a | **14,211** | **13,139** | **15,935** | **13,804** | **18,480** | **18,538** | **19,120** | **16,362** | **20,088** | **17,499** | **24,563** | **24,254** | | | |
| | Incentive Loadings to Capital | g | (2,730) | (2,390) | (2,950) | (2,510) | (3,700) | (4,020) | (2,560) | (2,650) | (2,910) | (2,960) | (4,280) | (3,840) | | | |
| | **Incentives Net of Capital** | | **11,481** | **10,749** | **12,985** | **11,294** | **14,780** | **14,518** | **16,560** | **13,712** | **17,178** | **14,539** | **20,283** | **20,414** | 93,266 | 85,227 | 0.91 |
| | ACI = Annual Cash Incentive | | | | | | | | | | | | | | | | |

**BEFORE THE PUBLIC UTILITY COMMISSION**

**OF OREGON**

**UE 335**

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| In the Matter of | ) |
| | ) |
| PORTLAND GENERAL ELECTRIC COMPANY, | ) |
| | ) |
| Request for a General Rate Revision. | ) |
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**EXHIBIT NO. AWEC/307**

**PGE RESPONSES TO DATA REQUESTS**

March 13, 2018

TO: Mark Brown
Public Utility Commission of Oregon

FROM: Stefan Brown
Manager, Regulatory Affairs

**PORTLAND GENERAL ELECTRIC**
**UE 335**
**PGE Response to ICNU Data Request No. 012**
**March 2, 2018**

**Request:**

**Please identify the amount included in the test year for PGE's energy supplier assessment. Please also explain whether this amount applies to PGE's 2018 ESA, its 2019 ESA, an average of the two, or something else.**

*Response:*

PGE included $2,068,281 in its 2019 test year forecast for the energy supplier assessment (ESA). This amount is the same as the 2016-2017 Oregon State Fiscal Year invoice. PGE's actual ESA cost for the 2017-2018 Oregon State Fiscal Year is $2,407,834.

Based on the recent years' increases in the ESA fees, PGE is currently forecasting to pay higher fees than the amount included in the test year revenue requirement.

March 13, 2018

TO: Mark Brown
Public Utility Commission of Oregon

FROM: Stefan Brown
Manager, Regulatory Affairs

**PORTLAND GENERAL ELECTRIC**
**UE 335**
**PGE Response to ICNU Data Request No. 013**
**March 2, 2018**

**Request:**

**Please explain why PGE chose not to join in the currently pending litigation over the energy supplier assessment.**

*Response:*

PGE objects to this request on the basis that the information it seeks is not relevant or reasonably calculated to lead to the discovery of admissible evidence in the current proceeding. Without waiving this objection, PGE responds as follows:

The current litigation involves the 2017 energy supplier assessment (ESA) made by the Oregon Department of Energy (ODOE) pursuant to ORS 469.421, and pursuant to a legislatively adopted expenditure limit. Initially, a small group of public utilities challenged the 2016 ESA, and the Marion County Circuit Court determined that the process followed by ODOE in making that assessment was not sufficient to meet the requirements of the statute. Subsequently, a larger group of public utilities challenged the 2017 ESA. Other than Cascade Natural Gas, no investor owned utility joined in either suit.

Ultimately, PGE decided to: 1) not join the suit over the 2017 ESA; but to 2) support the public utility petitioners in their appeal of the 2016 ESA, potentially by filing an Amicus brief. This decision was based on a number of factors including:

- The broader issues raised in the 2016 ESA case, including the question of whether the ESA is a tax or a fee, deserve additional judicial review.
- The raising of similar issues in the 2017 case, and the potential determination of those issues by a lower court, will have no additional effect on the legitimacy or legality of the ESA that is not already served by monitoring and participating in the appeal of the 2016 case.

- Any outcome in the 2016 ESA appeal will have no effect on the current funding cycle and, should the determination be negative for ODOE, will not affect expenditures in the current biennium.

April 26, 2018

TO: Tyler Pepple
Davison Van Cleve, P.C.

FROM: Stefan Brown
Manager, Regulatory Affairs

**PORTLAND GENERAL ELECTRIC**
**UE 335**
**PGE Response to AWEC Data Request No. 038**
**April 12, 2018**

**Request:**

**Please provide the amount of PGE's energy supplier assessment for each year since 2013 (inclusive).**

*Response:*

Attachment 038-A provides PGE’s energy supplier assessment payments from 2013 through 2017.

**UE 335 PGE Response to AWEC DR No. 038**
**Attachment 038-A**
**Page 1**

**PGE Energy Resource Supplier Assessment Payments to ODOE**

| Year | Amount Paid |
|---|---|
| 2013 | $ 1,373,770 |
| 2014 | $ 1,362,501 |
| 2015 | $ 1,971,706 |
| 2016 | $ 2,068,281 |
| 2017 | $ 2,407,834 |

May 9, 2018

TO: Hayley Thomas
Davison Van Cleve, P.C.

FROM: Stefan Brown
Manager, Regulatory Affairs

**PORTLAND GENERAL ELECTRIC**
**UE 335**
**PGE Response to AWEC Data Request No. 049**
**Dated April 25, 2018**

**Request:**

**Please refer to PGE/400, Mersereau – Neitzke/2, Table 1. For the three components listed, Wages and Salaries, Incentives and Benefits, provide:**

a. **both the Actuals and Budget for each year beginning 2012 through 2017, identifying dollar values separately for expensed and capitalized;**
b. **do Wages and Salaries reflect both union and non-union workers?**
c. **please list the incentives and the respective dollar amounts included. For example, do the values included in the table include officer incentives?**
d. **does the actual category and budget category encompass the same types of costs such that they are a direct match? If not, please explain.**

*Response:*

a. PGE’s Attachment 049-A provides the requested information. PGE is unable to provide budgeted health and dental plan information for 2012 at a greater level of detail because the accounts are not comparable to those from 2013-2017 due to the conversion of PGE’s accounting system.
b. Yes, wages and salaries represent both union and non-union employees.
c. PGE’s Attachment 049-A provides the requested information.
d. Yes, the budget and actual amounts represent the same type of costs. 2012 budget data are based on conversion data from PGE's prior accounting system and may not be fully comparable.

**Total Compensation Summary ($000)**

| Incentive Compensation | | 2012 Budget[d,f] | 2012 Actual | 2013 Budget | 2013 Actual | 2014 Budget | 2014 Actual | 2015 Budget | 2015 Actual | 2016 Budget | 2016 Actual | 2017 Budget | 2017 Actuals |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Total ACI** | | **5,071** | **5,200** | **5,855** | **5,181** | **6,361** | **6,620** | **6,542** | **6,404** | **6,659** | **5,448** | **6,548** | **7,379** |
| **Total Stock Incentive Plan** | | **3,550** | **4,269** | **4,632** | **4,323** | **5,476** | **5,918** | **6,352** | **6,023** | **6,957** | **6,427** | **7,335** | **6,668** |
| **Total Notables & Misc.** | | **267** | **448** | **257** | **666** | **257** | **807** | **257** | **1,036** | **307** | **1,502** | **662** | **1,215** |
| **Total Gross Incentives** | a | **17,744** | **17,816** | **21,176** | **18,138** | **24,745** | **25,255** | **26,318** | **23,510** | **27,957** | **24,526** | **32,498** | **32,064** |
| Incentive Loadings to Capital | g | (2,730) | (2,390) | (2,950) | (2,510) | (3,700) | (4,020) | (2,560) | (2,650) | (2,910) | (2,960) | (4,280) | (3,840) |
| **Incentives Net of Capital** | | **15,014** | **15,426** | **18,226** | **15,628** | **21,045** | **21,235** | **23,758** | **20,860** | **25,047** | **21,566** | **28,218** | **28,224** |
| ACI = Annual Cash Incentive | | | | | | | | | | | | | |
| **Wages & Salaries** | | | | | | | | | | | | | |
| Capital | b | 68,614 | 67,539 | 65,889 | 64,935 | 70,972 | 67,627 | 73,893 | 71,224 | 79,152 | 78,708 | 92,693 | 93,343 |
| O&M | b | 143,636 | 141,385 | 145,185 | 143,085 | 150,914 | 143,802 | 154,453 | 148,875 | 154,749 | 153,880 | 166,180 | 167,345 |
| **Gross Wages and Salaries** | | **212,249** | **208,924** | **211,074** | **208,020** | **221,886** | **211,429** | **228,345** | **220,099** | **233,901** | **232,588** | **258,873** | **260,689** |

| Benefit Compensation | 2012 Budget | 2012 Actual | 2013 Budget | 2013 Actual | 2014 Budget | 2014 Actual | 2015 Budget | 2015 Actual | 2016 Budget | 2016 Actual | 2017 Budget | 2017 Actuals |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Total Health & Dental Plan** | **37,016** | **37,098** | **39,425** | **37,269** | **39,298** | **38,843** | **41,160** | **40,797** | **41,759** | **40,548** | **45,472** | **40,759** |
| **Total Gross Benefits** | **81,934** | **82,452** | **94,505** | **90,869** | **92,308** | **89,555** | **90,704** | **92,398** | **91,000** | **90,919** | **96,751** | **90,218** |
| Benefits Loadings to Capital | (22,420) | (22,770) | (24,690) | (25,320) | (24,270) | (25,110) | (24,750) | (26,540) | (26,030) | (27,450) | (31,420) | (29,570) |
| **Benefits Net of Capital** | **59,514** | **59,682** | **69,815** | **65,549** | **68,038** | **64,445** | **65,954** | **65,858** | **64,970** | **63,469** | **65,331** | **60,648** |
| Total Gross Compensation | 311,927 | 309,192 | 326,755 | 317,026 | 338,939 | 326,239 | 345,367 | 336,006 | 352,858 | 348,033 | 388,122 | 382,971 |
| Total Compensation Net of Capital | 218,164 | 216,493 | 233,227 | 224,261 | 239,997 | 229,482 | 244,164 | 235,592 | 244,766 | 238,915 | 259,729 | 256,218 |
| **Total Compensation (as presented in Exhibit 400)** | **299,611** | **298,629** | **312,109** | **302,054** | **324,896** | **313,727** | **332,126** | **323,748** | **340,876** | **337,254** | **376,797** | **371,231** |

a Actual incentives reflect PGE's 100% of the Officer Long-term Incentive Program costs and of all other incentives plans.
b Split for capital and O&M actuals applied to capital and O&M budget split
c Pension cost forecast (before capitalization)
d 2012 Wages & Salaries do not include an unfilled position adjustment
e Accounts are not comparable to 2013-2017 at this level of detail
f 2012 Budget data is based on coversion data from PGE's prior accounting system and may not be fully comparable
g Only PIC and Notable Achievement Awards have capital loadings. ACI, Stock Incentives, Notable, and Miscellaneous Awards don't have capital loadings.

| | | 2012 Budget[d,f] | 2012 Actual | 2013 Budget | 2013 Actual | 2014 Budget | 2014 Actual | 2015 Budget | 2015 Actual | 2016 Budget | 2016 Actual | 2017 Budget | 2017 Actuals |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Incentive Compensation** | | | | | | | | | | | | | |
| | Capital | 15% | 13% | 14% | 14% | 15% | 16% | 10% | 11% | 10% | 12% | 13% | 12% |
| | Operating | 85% | 87% | 86% | 86% | 85% | 84% | 90% | 89% | 90% | 88% | 87% | 88% |
| **Wages & Salaries** | | | | | | | | | | | | | |
| | Capital | 32% | 32% | 31% | 31% | 32% | 32% | 32% | 32% | 34% | 34% | 36% | 36% |
| | Operating | 68% | 68% | 69% | 69% | 68% | 68% | 68% | 68% | 66% | 66% | 64% | 64% |
| **Benefit Compensation** | | | | | | | | | | | | | |
| | Capital | 27% | 28% | 26% | 28% | 26% | 28% | 27% | 29% | 29% | 30% | 32% | 33% |
| | Operating | 73% | 72% | 74% | 72% | 74% | 72% | 73% | 71% | 71% | 70% | 68% | 67% |

May 9, 2018

TO: Hayley Thomas
Davison Van Cleve, P.C.

FROM: Stefan Brown
Manager, Regulatory Affairs

**PORTLAND GENERAL ELECTRIC**
**UE 335**
**PGE Response to AWEC Data Request No. 066**
**Dated April 25, 2018**

**Request:**

**Please refer to PGE/400, Mersereau - Neitzke/17, lines 11-14.**

a. **Did PGE exclude all other components of compensation relating to the 99.9 FTE adjustment inclusive of wages and which is captured in the $10 million adjustment?**
b. **Please provide a breakdown of an adjustment of 99 .9 FTE for the components of total compensation such as wages and benefits.**
c. **Do the forecasted FTEs included in prior Tables include total FTE required, including vacancies, or are the totals net of vacancies and hence the number of FTEs listed are actually 99.9 FTE less than total PGE positions?**

*Response:*

a. PGE's $10 million wage and salary adjustment to expense costs represents vacancies and/or unfilled positions that occur during a calendar year. Except for vacation, the cost of the other components of total compensation such as benefits and incentives are not included in the $10 million. However, PGE budgets its benefits and incentives based on the most current information available and considering vacancies, as well as employee participation and qualification levels (e.g., PGE assumed 2,852 FTEs for medical benefits in 2019, which is approximately 15 FTE less than PGE's 2019 forecasted FTE, net of adjustments). At the same time, the calculations/estimates for some benefits are not based on FTEs, but on other factors, such as headcount. This is due to different timing, assumptions about their start and end dates, different offering, options, as well as rules and regulations.

   PGE's 2019 401(k) plan assumes 3,037 participants (headcount, not FTE). PGE's response to OPUC Data Request No. 223 provides the 401(k) participants from 2014-2019.

For the 2019 incentives budget detail, please see PGE's response to OPUC Data Request No. 191, Confidential Attachment B.

b. Please see response to item (a) above for explanation on how benefits and incentives are budgeted. PGE Exhibit 400 non-confidential workbook "2015 - 2019_FTE_W&S" provides wage and salary detail with the $10 million adjustment in 2019.

c. The FTE tables provided in PGE Exhibit 400 represent the total FTEs PGE requires to run its operations less the estimated 99.9 FTEs representing the $10 million adjustment for vacancies and/or unfilled positions.

May 9, 2018

TO: Hayley Thomas
Davison Van Cleve, P.C.

FROM: Stefan Brown
Manager, Regulatory Affairs

**PORTLAND GENERAL ELECTRIC**
**UE 335**
**PGE Response to AWEC Data Request No. 067**
**Dated April 25, 2018**

**Request:**

**Please refer to PGE/400, Mersereau- Neitzke/21, Table 7. Please:**

a. **provide values for Table 7 for total incentives PGE has budgeted for 2019 excluding any adjustment;**
b. **provide a breakdown of these values by the categories of officer, performance and merit based;**
c. **demonstrate that based on these values and the values provided in testimony that 100% of officer incentives have been excluded;**
d. **provide the value of total incentives paid by PGE, broken down by officer, performance and merit, for the years 2012 through 2017 inclusive.**

*Response:*

a. Attachment 067-A, column "J", provides the 2019 forecast without PGE's filing adjustments.
b. PGE's response to OPUC Data Request No. 191, Attach B_CONF provides the merit and financial breakdown requested.
c. Attachment 067 A, column "L", provides the total incentive adjustment, which matches the adjustment to PGE's revenue requirement as found in "Exhibit Support 2019_Tax Plan" file and "A&G" tab.
d. Attachment 067-A provides the 2012 to 2017 incentives paid by PGE broken down by incentive type. Incentives are paid based on PGE's financial performance and individual employee scorecard achievement. Please refer to the documentation provided as confidential work papers in PGE's Exhibit 400, for the financial and merit ratios applicable to each incentive plan.

**UE 335 PGE Response to AWEC DR No. 067**
**Attachment 067 A**
**Page 1**

**Total Incentives ($000)**

| Incentive Compensation | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 Budget | 2019 Forecast (Unadjusted) | 2019 Adjustment % | 2019 Adjustment Amount | 2019 Forecast (w/adjustments) |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Boardman PIC | 120 | 153 | 230 | 191 | 2 | - | - | - | | | - |
| Coyote Springs PIC | 408 | 191 | 251 | 466 | 438 | 39 | 370 | 384 | 50% | (192) | 192 |
| Port Westward PIC | 443 | 510 | 635 | 678 | 601 | 675 | 607 | 699 | 50% | (350) | 350 |
| Carty PIC | | | | - | 514 | 648 | 528 | 590 | 50% | (295) | 295 |
| Pelton PIC | 10 | 13 | 18 | 17 | 18 | 29 | 9 | 35 | 50% | (18) | 18 |
| Biglow Canyon PIC | 29 | 34 | 54 | 21 | 65 | 52 | 37 | 71 | 50% | (35) | 35 |
| Tucannon River PIC | | | | 24 | 12 | 22 | 32 | 42 | 50% | (21) | 21 |
| PGE General Operations PIC | 4,498 | 4,558 | 6,695 | 6,001 | 6,539 | 11,497 | 13,059 | 13,537 | 50% | (6,769) | 6,769 |
| **Total PIC** | **5,509** | **5,458** | **7,883** | **7,397** | **8,189** | **12,962** | **14,642** | **15,360** | | **(7,680)** | **7,680** |
| Boardman ACI | 45 | 22 | 15 | 35 | 14 | 3 | - | - | 50% | 0 | - |
| Pelton ACI | 14 | 18 | 18 | 17 | 15 | 20 | 21 | 22 | 50% | (11) | 11 |
| Wholesale Marketing ACI | 1,200 | 1,275 | 1,285 | 1,388 | 1,122 | 1,420 | 1,470 | 1,421 | 50% | (711) | 711 |
| PGE General Operations ACI | 2,304 | 2,540 | 3,052 | 2,616 | 2,321 | 3,137 | 2,974 | 3,348 | 50% | (1,674) | 1,674 |
| Officer ACI | 1,637 | 1,326 | 2,250 | 2,348 | 1,976 | 2,799 | 2,475 | 2,089 | 50% | (1,045) | 1,045 |
| **Total ACI** | **5,200** | **5,181** | **6,620** | **6,404** | **5,449** | **7,379** | **6,940** | **6,881** | | **(3,440)** | **3,440** |
| PGE Stock Incentives | 1,796 | 1,877 | 2,196 | 1,224 | 1,376 | 1,657 | 2,141 | 2,209 | 50% | (1,104) | 1,104 |
| Officer Stock Incentives | 2,473 | 2,446 | 3,721 | 4,049 | 4,228 | 4,157 | 5,281 | 4,945 | **100%** | (4,945) | - |
| Board of DirectorS Stock Incentives | | | | 750 | 823 | 854 | 900 | 936 | 50% | (468) | 468 |
| **Total Stock Incentive Plan** | **4,269** | **4,323** | **5,917** | **6,023** | **6,427** | **6,668** | **8,322** | **8,090** | | **(6,518)** | **1,572** |
| Notable Achievement Awards | 409 | 638 | 567 | 770 | 1,427 | 933 | 667 | 667 | 50% | (333) | 333 |
| Miscellaneous Awards | 39 | 28 | 240 | 266 | 75 | 282 | - | - | 0% | 0 | - |
| **Total Notables & Misc.** | **448** | **666** | **807** | **1,036** | **1,502** | **1,215** | **667** | **667** | | **(333)** | **333** |
| **Total Incentives** | **15,426** | **15,628** | **21,227** | **20,860** | **21,567** | **28,224** | **30,570** | **30,998** | | **(17,971)** | **13,026** |

PIC = Performance Incentive Compensation
ACI = Annual Cash Incentive

May 10, 2018

TO: Hayley Thomas
Davison Van Cleve, P.C.

FROM: Stefan Brown
Manager, Regulatory Affairs

**PORTLAND GENERAL ELECTRIC**
**UE 335**
**PGE Response to AWEC Data Request No. 073**
**Dated April 25, 2018**

**Request:**

**Please refer to PGE/400, Mersereau - Neitzke/36, lines 1 - 8.**

a. **Has PGE's proposal to update the discount rate under similar timelines as proposed in this case been proposed and accepted by other parties in prior PGE general rate cases?**
b. **Please describe the effects on the level of annual FAS 87 pension costs if the discount rate increases by 0.1 percent.**
c. **Is the effect on FAS 87 pension costs linearly related to each percentage point change in discount rate?**

*Response:*

a. PGE made a similar request in its 2018 test-year general rate case (Docket No. UE 319). During that proceeding, PGE provided (via PGE's first supplemental response to OPUC Data Request No. 178) updated discount rates for both pension and post-retirement costs. These changes resulted in a net-neutral effect to costs. Ultimately, no change to discount rates for either pension or post-retirement costs were proposed or made during the UE 319 proceeding.

b. A 10 basis point increase to PGE's discount rate used for FAS 87 pension expense would reduce PGE's gross (i.e., pre-capitalization) pension expense by approximately $860,000.

c. No. As discount rates decrease, the sensitivity (on a percentage basis) to changes is more pronounced. Similarly, as discount rates increase, the sensitivity to changes is lower on an overall percent change basis.

May 14, 2018

TO: Hayley Thomas
Davison Van Cleve, P.C.

FROM: Stefan Brown
Manager, Regulatory Affairs

**PORTLAND GENERAL ELECTRIC**
**UE 335**
**PGE Response to AWEC Data Request No. 093**
**May 1, 2018**

**Request:**

**Please identify, for each year of the time period 2010 through 2019, inclusive;**

a. **PGE gross and net distribution plant;**
b. **By month for the same time period, PGE residential, commercial, industrial and total retail loads, unadjusted;**
c. **PGE residential, commercial, industrial and total retail loads normalized for the weather;**
d. **PGE residential, commercial, industrial and total retail loads normalized for weather;**
e. **The number of each of residential, commercial, industrial and total retail customers year end; and**
f. **Actual and budgeted medical expense separated out by union and non-union**

**For the years 2018 and 2019, only projected values, consistent with PGE's general rate filing need be provided, as available.**

*Response:*

a. Attachment 093-A provides the requested information for 2010 to 2017. PGE's response to OPUC Data Request No. 128, Attachment 128-D, provides the forecasted 2018 year-end balances. PGE is not filing 2019 year-end balances in this rate case.
b. Attachment 093-B provides the requested information.
c. Attachment 093-C provides the requested information.
d. Attachment 093-C provides the requested information.
e. Attachment 093-D provides the requested information.
f. Attachment 093-E provides the requested information.

Attachment 093-E is protected information and subject to Protective Order 18-047.

AWEC 93 (a) PGE Gross and Net Plant Balance for Electric Plant in Service Classified as Distribution

Data is from PGE's filed FERC Form 1 for each year from 2010 through 2017.

| YEAR | Plant | Reserve | Net Plant |
|---|---|---|---|
| 2010 | $ 2,569,836,052 | $ 1,380,886,914 | $ 1,188,949,138 |
| 2011 | $ 2,690,710,541 | $ 1,479,972,471 | $ 1,210,738,070 |
| 2012 | $ 2,809,739,430 | $ 1,585,049,949 | $ 1,224,689,481 |
| 2013 | $ 2,939,069,492 | $ 1,686,819,395 | $ 1,252,250,097 |
| 2014 | $ 3,070,652,586 | $ 1,792,248,824 | $ 1,278,403,762 |
| 2015 | $ 3,186,283,644 | $ 1,849,206,854 | $ 1,337,076,790 |
| 2016 | $ 3,334,113,440 | $ 1,939,890,596 | $ 1,394,222,844 |
| 2017 | $ 3,534,104,917 | $ 2,028,237,016 | $ 1,505,867,901 |

**UE 335 PGE Response to AWEC DR No. 093**
**Attachment 093-A**
**Page 1**

b. by month for the same time (2010-2019) period, PGE residential commercial industrial and total retail loads, unadjusted

**Monthly Energy Deliveries, actual through 2017, in thousands of MWh**

| Year | Month | Residential | Commercial | Industrial | Total |
|---|---|---|---|---|---|
| 2010 | 1 | 874 | 642 | 321 | 1,836 |
| 2010 | 2 | 726 | 619 | 317 | 1,661 |
| 2010 | 3 | 662 | 599 | 304 | 1,565 |
| 2010 | 4 | 617 | 572 | 309 | 1,498 |
| 2010 | 5 | 553 | 562 | 312 | 1,427 |
| 2010 | 6 | 540 | 582 | 323 | 1,444 |
| 2010 | 7 | 536 | 612 | 326 | 1,475 |
| 2010 | 8 | 568 | 677 | 347 | 1,592 |
| 2010 | 9 | 539 | 647 | 344 | 1,529 |
| 2010 | 10 | 509 | 599 | 347 | 1,455 |
| 2010 | 11 | 595 | 600 | 350 | 1,546 |
| 2010 | 12 | 810 | 626 | 357 | 1,792 |
| 2011 | 1 | 882 | 654 | 353 | 1,889 |
| 2011 | 2 | 765 | 616 | 361 | 1,742 |
| 2011 | 3 | 769 | 637 | 342 | 1,747 |
| 2011 | 4 | 651 | 583 | 335 | 1,569 |
| 2011 | 5 | 580 | 564 | 335 | 1,479 |
| 2011 | 6 | 533 | 582 | 344 | 1,458 |
| 2011 | 7 | 504 | 608 | 342 | 1,454 |
| 2011 | 8 | 533 | 659 | 368 | 1,559 |
| 2011 | 9 | 562 | 674 | 365 | 1,601 |
| 2011 | 10 | 515 | 602 | 348 | 1,466 |
| 2011 | 11 | 617 | 591 | 342 | 1,550 |
| 2011 | 12 | 813 | 638 | 330 | 1,781 |
| 2012 | 1 | 889 | 668 | 339 | 1,897 |
| 2012 | 2 | 780 | 646 | 351 | 1,777 |
| 2012 | 3 | 737 | 621 | 338 | 1,695 |
| 2012 | 4 | 629 | 576 | 338 | 1,543 |
| 2012 | 5 | 534 | 572 | 347 | 1,453 |
| 2012 | 6 | 510 | 586 | 362 | 1,457 |
| 2012 | 7 | 525 | 622 | 356 | 1,503 |
| 2012 | 8 | 548 | 649 | 359 | 1,556 |
| 2012 | 9 | 537 | 658 | 373 | 1,568 |
| 2012 | 10 | 498 | 603 | 367 | 1,468 |
| 2012 | 11 | 584 | 584 | 362 | 1,530 |
| 2012 | 12 | 758 | 621 | 343 | 1,722 |
| 2013 | 1 | 894 | 649 | 355 | 1,898 |
| 2013 | 2 | 763 | 608 | 351 | 1,723 |
| 2013 | 3 | 669 | 585 | 329 | 1,584 |
| 2013 | 4 | 584 | 576 | 346 | 1,506 |
| 2013 | 5 | 541 | 597 | 354 | 1,493 |
| 2013 | 6 | 513 | 597 | 357 | 1,467 |
| 2013 | 7 | 558 | 641 | 351 | 1,550 |
| 2013 | 8 | 564 | 671 | 369 | 1,604 |
| 2013 | 9 | 566 | 673 | 385 | 1,624 |
| 2013 | 10 | 529 | 583 | 357 | 1,469 |
| 2013 | 11 | 582 | 576 | 357 | 1,515 |
| 2013 | 12 | 879 | 667 | 360 | 1,906 |
| 2014 | 1 | 879 | 656 | 368 | 1,902 |
| 2014 | 2 | 794 | 617 | 347 | 1,758 |
| 2014 | 3 | 679 | 599 | 322 | 1,599 |
| 2014 | 4 | 586 | 577 | 352 | 1,515 |
| 2014 | 5 | 532 | 586 | 339 | 1,457 |
| 2014 | 6 | 495 | 613 | 354 | 1,462 |
| 2014 | 7 | 554 | 650 | 360 | 1,564 |
| 2014 | 8 | 614 | 692 | 374 | 1,680 |
| 2014 | 9 | 581 | 698 | 392 | 1,672 |
| 2014 | 10 | 489 | 601 | 358 | 1,447 |
| 2014 | 11 | 572 | 588 | 364 | 1,525 |

**UE 335 PGE Response to AWEC DR No. 093**
**Attachment 093-A**
**Page 2**

| | | | | | |
|---|---|---|---|---|---|
| 2014 | 12 | 783 | 653 | 374 | 1,809 |
| 2015 | 1 | 803 | 640 | 380 | 1,822 |
| 2015 | 2 | 655 | 592 | 362 | 1,609 |
| 2015 | 3 | 590 | 579 | 359 | 1,528 |
| 2015 | 4 | 560 | 577 | 364 | 1,501 |
| 2015 | 5 | 519 | 590 | 373 | 1,482 |
| 2015 | 6 | 527 | 631 | 392 | 1,550 |
| 2015 | 7 | 646 | 705 | 393 | 1,743 |
| 2015 | 8 | 615 | 696 | 398 | 1,708 |
| 2015 | 9 | 553 | 671 | 413 | 1,638 |
| 2015 | 10 | 478 | 594 | 378 | 1,450 |
| 2015 | 11 | 562 | 597 | 392 | 1,551 |
| 2015 | 12 | 806 | 643 | 374 | 1,824 |
| 2016 | 1 | 877 | 666 | 338 | 1,881 |
| 2016 | 2 | 674 | 598 | 335 | 1,608 |
| 2016 | 3 | 625 | 582 | 317 | 1,525 |
| 2016 | 4 | 555 | 575 | 330 | 1,460 |
| 2016 | 5 | 499 | 569 | 336 | 1,404 |
| 2016 | 6 | 532 | 628 | 345 | 1,505 |
| 2016 | 7 | 520 | 623 | 346 | 1,488 |
| 2016 | 8 | 553 | 643 | 365 | 1,561 |
| 2016 | 9 | 571 | 661 | 364 | 1,596 |
| 2016 | 10 | 494 | 585 | 351 | 1,429 |
| 2016 | 11 | 539 | 578 | 343 | 1,460 |
| 2016 | 12 | 765 | 628 | 362 | 1,755 |
| 2017 | 1 | 993 | 678 | 351 | 2,022 |
| 2017 | 2 | 845 | 651 | 358 | 1,855 |
| 2017 | 3 | 731 | 631 | 337 | 1,699 |
| 2017 | 4 | 603 | 581 | 343 | 1,527 |
| 2017 | 5 | 544 | 569 | 356 | 1,469 |
| 2017 | 6 | 528 | 610 | 365 | 1,503 |
| 2017 | 7 | 560 | 641 | 355 | 1,556 |
| 2017 | 8 | 616 | 677 | 377 | 1,670 |
| 2017 | 9 | 615 | 688 | 389 | 1,692 |
| 2017 | 10 | 515 | 605 | 359 | 1,478 |
| 2017 | 11 | 569 | 578 | 344 | 1,491 |
| 2017 | 12 | 767 | 644 | 350 | 1,760 |
| 2018 (f) | 1 | 879 | 650 | 343 | 1,873 |
| 2018 (f) | 2 | 756 | 613 | 340 | 1,709 |
| 2018 (f) | 3 | 694 | 606 | 332 | 1,632 |
| 2018 (f) | 4 | 596 | 576 | 338 | 1,510 |
| 2018 (f) | 5 | 529 | 570 | 339 | 1,438 |
| 2018 (f) | 6 | 516 | 607 | 345 | 1,468 |
| 2018 (f) | 7 | 540 | 633 | 353 | 1,526 |
| 2018 (f) | 8 | 577 | 670 | 366 | 1,614 |
| 2018 (f) | 9 | 570 | 676 | 372 | 1,618 |
| 2018 (f) | 10 | 498 | 595 | 355 | 1,447 |
| 2018 (f) | 11 | 567 | 576 | 346 | 1,488 |
| 2018 (f) | 12 | 789 | 618 | 352 | 1,759 |
| 2019 (f) | 1 | 881 | 642 | 349 | 1,871 |
| 2019 (f) | 2 | 756 | 605 | 345 | 1,706 |
| 2019 (f) | 3 | 693 | 598 | 338 | 1,628 |
| 2019 (f) | 4 | 594 | 567 | 343 | 1,505 |
| 2019 (f) | 5 | 527 | 562 | 344 | 1,433 |
| 2019 (f) | 6 | 514 | 599 | 351 | 1,463 |
| 2019 (f) | 7 | 540 | 625 | 359 | 1,523 |
| 2019 (f) | 8 | 578 | 662 | 372 | 1,612 |
| 2019 (f) | 9 | 571 | 668 | 377 | 1,616 |
| 2019 (f) | 10 | 497 | 586 | 361 | 1,443 |
| 2019 (f) | 11 | 566 | 566 | 351 | 1,484 |
| 2019 (f) | 12 | 790 | 609 | 358 | 1,757 |

c. and d. PGE residential commercial industrial and total retail loads normalized for weather

**Monthly Energy Deliveries, actual through 2017, weather adjusted, in thousands of MWh**

| Year | Month | Residential | Commercial | Industrial | Total |
|---|---|---|---|---|---|
| 2010 | 1 | 848 | 638 | 320 | 1,806 |
| 2010 | 2 | 793 | 630 | 319 | 1,742 |
| 2010 | 3 | 703 | 604 | 305 | 1,612 |
| 2010 | 4 | 603 | 571 | 309 | 1,482 |
| 2010 | 5 | 541 | 563 | 312 | 1,416 |
| 2010 | 6 | 514 | 587 | 324 | 1,424 |
| 2010 | 7 | 530 | 619 | 328 | 1,477 |
| 2010 | 8 | 579 | 686 | 349 | 1,614 |
| 2010 | 9 | 541 | 654 | 345 | 1,540 |
| 2010 | 10 | 521 | 600 | 347 | 1,467 |
| 2010 | 11 | 608 | 602 | 350 | 1,560 |
| 2010 | 12 | 774 | 621 | 356 | 1,751 |
| 2011 | 1 | 867 | 651 | 353 | 1,871 |
| 2011 | 2 | 792 | 619 | 361 | 1,773 |
| 2011 | 3 | 704 | 627 | 341 | 1,672 |
| 2011 | 4 | 609 | 577 | 334 | 1,520 |
| 2011 | 5 | 548 | 564 | 335 | 1,447 |
| 2011 | 6 | 510 | 585 | 345 | 1,440 |
| 2011 | 7 | 519 | 620 | 344 | 1,483 |
| 2011 | 8 | 554 | 674 | 370 | 1,598 |
| 2011 | 9 | 554 | 664 | 364 | 1,582 |
| 2011 | 10 | 519 | 599 | 347 | 1,465 |
| 2011 | 11 | 611 | 588 | 341 | 1,541 |
| 2011 | 12 | 786 | 631 | 329 | 1,746 |
| 2012 | 1 | 902 | 664 | 339 | 1,905 |
| 2012 | 2 | 782 | 646 | 351 | 1,779 |
| 2012 | 3 | 704 | 615 | 337 | 1,656 |
| 2012 | 4 | 615 | 574 | 338 | 1,527 |
| 2012 | 5 | 547 | 571 | 347 | 1,465 |
| 2012 | 6 | 508 | 589 | 363 | 1,459 |
| 2012 | 7 | 528 | 626 | 357 | 1,511 |
| 2012 | 8 | 552 | 649 | 359 | 1,560 |
| 2012 | 9 | 537 | 656 | 372 | 1,565 |
| 2012 | 10 | 506 | 602 | 366 | 1,475 |
| 2012 | 11 | 615 | 591 | 362 | 1,569 |
| 2012 | 12 | 804 | 629 | 344 | 1,777 |
| 2013 | 1 | 870 | 642 | 354 | 1,866 |
| 2013 | 2 | 758 | 608 | 351 | 1,718 |
| 2013 | 3 | 690 | 588 | 330 | 1,608 |
| 2013 | 4 | 621 | 580 | 346 | 1,547 |
| 2013 | 5 | 566 | 597 | 354 | 1,516 |
| 2013 | 6 | 523 | 599 | 358 | 1,480 |
| 2013 | 7 | 555 | 633 | 350 | 1,537 |
| 2013 | 8 | 565 | 671 | 369 | 1,605 |
| 2013 | 9 | 555 | 662 | 384 | 1,600 |
| 2013 | 10 | 503 | 584 | 357 | 1,444 |
| 2013 | 11 | 590 | 576 | 357 | 1,523 |
| 2013 | 12 | 813 | 651 | 358 | 1,822 |
| 2014 | 1 | 880 | 651 | 367 | 1,898 |
| 2014 | 2 | 733 | 614 | 346 | 1,692 |

| | | | | | |
|---|---|---|---|---|---|
| 2014 | 3 | 684 | 602 | 322 | 1,608 |
| 2014 | 4 | 619 | 582 | 353 | 1,554 |
| 2014 | 5 | 554 | 584 | 339 | 1,477 |
| 2014 | 6 | 522 | 616 | 355 | 1,492 |
| 2014 | 7 | 551 | 644 | 359 | 1,554 |
| 2014 | 8 | 597 | 678 | 372 | 1,646 |
| 2014 | 9 | 571 | 686 | 390 | 1,648 |
| 2014 | 10 | 515 | 596 | 357 | 1,468 |
| 2014 | 11 | 597 | 595 | 365 | 1,557 |
| 2014 | 12 | 795 | 656 | 374 | 1,825 |
| 2015 | 1 | 862 | 651 | 381 | 1,895 |
| 2015 | 2 | 766 | 615 | 365 | 1,746 |
| 2015 | 3 | 690 | 600 | 362 | 1,652 |
| 2015 | 4 | 616 | 588 | 366 | 1,569 |
| 2015 | 5 | 550 | 594 | 373 | 1,516 |
| 2015 | 6 | 523 | 614 | 390 | 1,527 |
| 2015 | 7 | 551 | 661 | 386 | 1,598 |
| 2015 | 8 | 569 | 679 | 395 | 1,643 |
| 2015 | 9 | 537 | 667 | 413 | 1,617 |
| 2015 | 10 | 502 | 594 | 377 | 1,473 |
| 2015 | 11 | 601 | 603 | 392 | 1,595 |
| 2015 | 12 | 800 | 645 | 375 | 1,819 |
| 2016 | 1 | 866 | 666 | 338 | 1,870 |
| 2016 | 2 | 786 | 624 | 338 | 1,748 |
| 2016 | 3 | 710 | 602 | 319 | 1,632 |
| 2016 | 4 | 616 | 584 | 331 | 1,530 |
| 2016 | 5 | 538 | 566 | 335 | 1,439 |
| 2016 | 6 | 522 | 617 | 343 | 1,482 |
| 2016 | 7 | 531 | 626 | 347 | 1,503 |
| 2016 | 8 | 556 | 644 | 365 | 1,565 |
| 2016 | 9 | 549 | 654 | 363 | 1,566 |
| 2016 | 10 | 506 | 589 | 351 | 1,446 |
| 2016 | 11 | 610 | 595 | 345 | 1,549 |
| 2016 | 12 | 814 | 639 | 364 | 1,817 |
| 2017 | 1 | 852 | 643 | 347 | 1,843 |
| 2017 | 2 | 742 | 630 | 355 | 1,728 |
| 2017 | 3 | 691 | 623 | 336 | 1,650 |
| 2017 | 4 | 600 | 582 | 343 | 1,525 |
| 2017 | 5 | 524 | 565 | 356 | 1,445 |
| 2017 | 6 | 520 | 603 | 364 | 1,487 |
| 2017 | 7 | 549 | 634 | 354 | 1,537 |
| 2017 | 8 | 589 | 668 | 376 | 1,634 |
| 2017 | 9 | 553 | 663 | 385 | 1,601 |
| 2017 | 10 | 493 | 600 | 358 | 1,451 |
| 2017 | 11 | 581 | 582 | 345 | 1,508 |
| 2017 | 12 | 803 | 653 | 351 | 1,807 |
| 2018 (f) | 1 | 879 | 650 | 343 | 1,873 |
| 2018 (f) | 2 | 756 | 613 | 340 | 1,709 |
| 2018 (f) | 3 | 694 | 606 | 332 | 1,632 |
| 2018 (f) | 4 | 596 | 576 | 338 | 1,510 |
| 2018 (f) | 5 | 529 | 570 | 339 | 1,438 |
| 2018 (f) | 6 | 516 | 607 | 345 | 1,468 |
| 2018 (f) | 7 | 540 | 633 | 353 | 1,526 |
| 2018 (f) | 8 | 577 | 670 | 366 | 1,614 |
| 2018 (f) | 9 | 570 | 676 | 372 | 1,618 |

**PGE Response to AWEC DR No. 093**
**Attachment 093-C**
**Page 3**

| | | | | | |
|---|---|---|---|---|---|
| 2018 (f) | 10 | 498 | 595 | 355 | 1,447 |
| 2018 (f) | 11 | 567 | 576 | 346 | 1,488 |
| 2018 (f) | 12 | 789 | 618 | 352 | 1,759 |
| 2019 (f) | 1 | 881 | 642 | 349 | 1,871 |
| 2019 (f) | 2 | 756 | 605 | 345 | 1,706 |
| 2019 (f) | 3 | 693 | 598 | 338 | 1,628 |
| 2019 (f) | 4 | 594 | 567 | 343 | 1,505 |
| 2019 (f) | 5 | 527 | 562 | 344 | 1,433 |
| 2019 (f) | 6 | 514 | 599 | 351 | 1,463 |
| 2019 (f) | 7 | 540 | 625 | 359 | 1,523 |
| 2019 (f) | 8 | 578 | 662 | 372 | 1,612 |
| 2019 (f) | 9 | 571 | 668 | 377 | 1,616 |
| 2019 (f) | 10 | 497 | 586 | 361 | 1,443 |
| 2019 (f) | 11 | 566 | 566 | 351 | 1,484 |
| 2019 (f) | 12 | 790 | 609 | 358 | 1,757 |

e. the number for each of residential, commercial, industrial, and total retail customers year end

**End of Period Customer Count, actual through 2017**

| Year | Residential | Commercial | Industrial | Total |
|---|---|---|---|---|
| 2010 | 719,031 | 101,385 | 260 | 820,676 |
| 2011 | 721,216 | 101,942 | 255 | 823,413 |
| 2012 | 725,502 | 102,594 | 258 | 828,354 |
| 2013 | 732,341 | 103,541 | 260 | 836,142 |
| 2014 | 738,008 | 104,010 | 255 | 842,273 |
| 2015 | 746,969 | 104,940 | 255 | 852,164 |
| 2016 | 756,675 | 105,826 | 263 | 862,764 |
| 2017 | 767,012 | 107,289 | 267 | 874,568 |
| 2018(f) | 776,233 | 108,274 | 269 | 884,776 |
| 2019(f) | 785,781 | 109,381 | 271 | 895,433 |

(f) refers to forecasted loads.

| **Benefit Compensation ($000)** | **2012 Budget[a,b]** | **2012 Actual** | **2013 Budget** | **2013 Actual** | **2014 Budget** | **2014 Actual** |
|---|---|---|---|---|---|---|
| Active Union Health & Dental | c | 11,003 | 12,007 | 12,226 | 12,713 | 13,485 |
| Retiree Union Health & Dental | c | 1,797 | 2,026 | 1,859 | 1,750 | 1,852 |
| Active Non-Union Health & Dental | c | 23,175 | 23,704 | 21,804 | 23,225 | 22,035 |
| Retiree Non-Union Health & Dental | c | 967 | 1,487 | 1,179 | 1,209 | 1,265 |
| Health & Dental Administration | c | 156 | 201 | 201 | 401 | 205 |
| **Total Health & Dental Plan** | **37,016** | **37,098** | **39,425** | **37,269** | **39,298** | **38,843** |

a 2012 Budget data is based on conversion data from PGE's prior accounting system and may not be fully comparable
b Accounts are not comparable to 2013-2017 at this level of detail

| 2015 Budget | 2015 Actual | 2016 Budget | 2016 Actual | 2017 Budget | 2017 Actuals | 2018 Budget | 2019 Forecast |
|---|---|---|---|---|---|---|---|
| 12,817 | 13,612 | 12,001 | 11,650 | 13,068 | 12,087 | 14,412 | 15,088 |
| 1,609 | 1,510 | 1,394 | 263 | 304 | 19 | 375 | 375 |
| 25,026 | 24,047 | 26,734 | 26,547 | 30,193 | 27,743 | 34,654 | 36,721 |
| 1,344 | 1,234 | 1,307 | 1,570 | 1,542 | 731 | 660 | 792 |
| 364 | 394 | 323 | 518 | 365 | 179 | 402 | 407 |
| **41,160** | **40,797** | **41,759** | **40,548** | **45,472** | **40,759** | **50,503** | **53,383** |

May 29, 2018

TO: Hayley Thomas
Davison Van Cleve, P.C.

FROM: Stefan Brown
Manager, Regulatory Affairs

**PORTLAND GENERAL ELECTRIC**
**UE 335**
**PGE Response to AWEC Data Request No. 137**
**Dated May 15, 2018**

**Request:**

**Please provide PGE's energy supplier assessment for the fiscal year beginning July 1, 2018 when it is available.**

*Response:*

Attachment 137-A provides the invoice for PGE's energy supplier assessment for the fiscal year beginning July 1, 2018. PGE will provide a supplemental response with a signed copy of the assessment on the payment due date by June 30, 2018.

**OREGON DEPARTMENT OF ENERGY**
625 MARION STREET NE
SALEM, OR 97301-3737
PHONE: (503) 378-3268
OREGON TOLL FREE 1-800-221-8035 x368
FEDERAL ID NO: 93-0643773

| INVOICE NUMBER | INVOICE DATE | PAYMENT DUE |
|---|---|---|
| **AR190463** | **05/22/18** | **06/30/18** |

PORTLAND GENERAL ELECTRIC
ATTN: NATALIA PAVLOVA/JEFF STEVENS
121 SW SALMON ST
ONE WORLD TRADE CTR 5TH FLR (1WTC0501)
PORTLAND, OR. 97204

| DESCRIPTION | CHARGES |
|---|---|
| Energy Resource Supplier Assessment - State Fiscal Year 2018-2019<br>Calendar year 2017 | 2,412,208.00 |
| | Amount Due |
| | **$ 2,412,208.00** |

For questions concerning this invoice, call (503) 378-3268.
Please return the remittance copy or include the invoice number on your check stub.

***ORS469.421 (11) (B), REQUIRES A PENALTY FEE OF 2% PER MONTH TO BE ASSESSED ON ALL PAST DUE BALANCES***

**CUSTOMER COPY**

**OREGON DEPARTMENT OF ENERGY**
625 MARION STREET NE
SALEM, OR 97301-3737
PHONE: (503) 378-3268
OREGON TOLL FREE 1-800-221-8035 x368
FEDERAL ID NO: 93-0643773

| INVOICE NUMBER | INVOICE DATE | PAYMENT DUE |
| --- | --- | --- |
| **AR190463** | **05/22/18** | **06/30/18** |

PORTLAND GENERAL ELECTRIC
ATTN: NATALIA PAVLOVA/JEFF STEVENS
121 SW SALMON ST
ONE WORLD TRADE CTR 5TH FLR (1WTC0501)
PORTLAND, OR. 97204

| DESCRIPTION | CHARGES |
| --- | --- |
| Energy Resource Supplier Assessment - State Fiscal Year 2018-2019<br>Calendar year 2017 | 2,412,208.00 |
| | Amount Due |
| | **$ 2,412,208.00** |

For questions concerning this invoice, call (503) 378-3268.
Please return the remittance copy or include the invoice number on your check stub.

***ORS469.421 (11) (B), REQUIRES A PENALTY FEE OF 2% PER MONTH TO BE ASSESSED ON ALL PAST DUE BALANCES***

| APPROVAL |
| --- |
| N/A |

**REMITTANCE COPY**

| FISCAL INFO ONLY |
| --- |
| GRANT/PH NO: A01301/70<br>T CODE: 199 PCA: 93066<br>AOBJ: 0401 |

February 15, 2018

TO: Kay Barnes
Public Utility Commission of Oregon

FROM: Stefan Brown
Manager, Regulatory Affairs

**PORTLAND GENERAL ELECTRIC**
**UE 335**
**PGE Response to OPUC Standard Data Request No. 060**
**Dated February 15, 2018**

**Request:**

**For FAS 87 and FAS 106, please provide the estimated effect on the Test Period Net periodic postretirement cost (income) if the discount rate is changed 25 basis points in both directions and expected rate of return is changed 25 basis points in both directions.**

*Response:*

*FAS 87*
For FAS 87, the 2019 test year cost sensitivity to a +/- 25 basis point change in the discount rate is not symmetrical.

- A 25 basis point increase in the discount rate decreases costs by approximately $2.1 million.
- A 25 basis point decrease in the discount rate increases costs by approximately $2.2 million.

The 2019 test year cost sensitivity to a +/- 25 basis point change in the expected rate of return is approximately $1.5 million (i.e., a 25 basis point increase reduces costs by $1.5 million, and a 25 basis point decrease increases costs by $1.5 million).

*FAS 106*
For FAS 106, the 2019 test year cost sensitivity to a +/- 25 basis point change in the discount rate is not symmetrical.

- A 25 basis point increase in the discount rate decreases costs by approximately $0.12 million.
- A 25 basis point decrease in the discount rate increases costs by approximately $0.14 million.

The 2019 test year cost sensitivity to a +/- 25 basis point change in the expected rate of return is approximately $0.79 million (i.e., a 25 basis point increase reduces costs by $0.79 million, and a 25 basis point decrease increases costs by $0.79 million).

**BEFORE THE PUBLIC UTILITY COMMISSION**

**OF OREGON**

**UE 335**

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

**EXHIBIT NO. AWEC/308**

**CENTRAL LINCOLN PEOPLE'S UTILITY DIST.**
**v.**
**OREGON DEPT. OF ENERGY, MARION COUNTY CIR. CT. CASE NO. 16CV18269**
**(AUG. 9, 2017)**

**CIRCUIT COURT OF OREGON**
**THIRD JUDICIAL DISTRICT**
**MARION COUNTY COURTHOUSE**
**P.O. BOX 12869**
**SALEM, OR 97309-0869**

TRACY A. PRALL
*Circuit Court Judge*
(503) 588-5030
Fax: (503) 588-5109

August 9, 2017

Brad Daniels and
Eric Kodesch
Stoel Rives LLP
760 SW Ninth Ave Ste 3000
Portland OR 97205
**VIA EMAIL ONLY**

Carla Scott
DOJ Trial Division
100 SW Market St
Portland OR 97201
**VIA EMAIL ONLY**

Marilyn Harbur
DOJ GC Tax & Finance
1162 Court St NE
Salem OR 97301
**VIA EMAIL ONLY**

RE: ***Central Lincoln People's Utility District, et al v. Oregon Department of Energy, et al***
Marion County Circuit Court Case No. 16CV18269

Counsel,

This matter came before the court on June 29, 2017, for hearing on cross Motions for Summary Judgment. Petitioners appeared by and through counsel, Brad Daniels and Eric Kodesch. Respondents appeared by and through counsel, Carla Scott and Marilyn Harbur. The court reviewed the Motions, Responses, and Replies and heard oral argument. The court then took the matter under advisement.

Now, having fully considered this matter, the court makes the following findings of fact and conclusions of law:

## STATEMENT OF FACTS

Central Lincoln People's Utility District, City of Hermiston d/b/a Hermiston Energy Services, Clatskanie People's Utility District, Columbia River People's Utility District, Consumers Power Inc., Emerald People's Utility District, Eugene Water & Electric Board, Northern Wasco People's Utility District, Tillamook People's Utility District, and Umatilla Electric Cooperative (collectively, "Petitioners") are municipal cooperative corporations that qualify as energy resource suppliers. Under ORS 469.421(8)(i)(A), an "energy resource supplier" is, "an electric utility, natural gas utility or petroleum supplier supplying, generating, transmitting or distributing electricity, natural gas or petroleum products in Oregon."

Petitioners bring a claim against the Oregon Department of Energy ("ODOE") and the ODOE director Michael Kaplan (collectively, "Respondents"). The ODOE regulates energy facilities and develops programs and activities to increase energy efficiency. Some of ODOE's public duties include serving as a "central repository…for the collection of data on energy resources," "inform[ing] and educat[ing] the public about energy problems and ways in which the public can conserve energy resources," and "administer[ing] federal and state energy allocation and conservation programs and energy research and development programs." ORS 469.030(2)(a)-(b), (e). To fund those programs and activities, ORS 469.421(8)(a) requires "each energy resource supplier pay to the department annually its share of an assessment to fund the programs and activities of the council and the department," known as the Energy Supplier Assessment ("ESA").

Each petitioner received an Order Determining and Allocating Assessment and Implementing Provisions (collectively "Orders") for the 2016-17 fiscal year. After receiving the Orders, petitioners filed this Petition for Review pursuant to ORS 183.484. Petitioners and respondents filed Cross-Motions for Summary Judgment.

## SUMMARY JUDGMENT STANDARD

Under the APA, the court determines whether a final state agency order is supported by substantial evidence and whether the agency has correctly applied the law. ORS 183.484(5). In deciding whether to grant a motion for summary judgment, the appropriate inquiry is whether there is substantial evidence in the record before the circuit court to support the agency's determination. Where no disputed issues of material fact exist, the court's inquiry is purely legal in nature. ORS 183.484 grants the court authority to:

> (5)(a)…affirm, reverse, or remand the order. If the court finds that the agency has erroneously interpreted a provision of law and that a correct interpretation compels a particular action, it shall:
>
> (A) Set aside or modify the order; or
>
> (B) Remand the case to the agency for further action under a correct interpretation of the provision of law.
>
> (b) The court shall remand the order to the agency if it finds the agency's exercise of discretion to be:
>
> (A) Outside the range of discretion delegated to the agency by law;
>
> (B) Inconsistent with an agency rule, an officially stated agency position, or a prior agency practice, if the inconsistency is not explained by the agency; or
>
> (C) Otherwise in violation of a constitutional or statutory provision.
>
> (c) The court shall set aside or remand the order if it finds that the order is not supported by substantial evidence in the record. Substantial evidence exists to support a finding of fact when the record, viewed as a whole, would permit a reasonable person to make that finding. ORS 183.484(5)(a)-(c).

## MOTIONS FOR SUMMARY JUDGMENT

On summary judgment, petitioners move the court to: (1) Declare the ESA is a tax; (2) Declare SB 5510 is subject to Oregon constitutional requirements for bills raising revenue; (3) Declare the ODOE and Michael Kaplan did not follow statutory procedures before including the ESA in the agency's 2015-17 budget; (4) Set aside the Orders imposing the 2016 ESA and refund the ESA amounts paid by petitioners; and (5) Enjoin collection of ESA until ODOE complies with the Oregon Constitution and ORS 469.421(8). Respondents move the court to declare, as a matter of law, that the ODOE lawfully issued the ESA to petitioners in 2016.

### I. Is the ESA a tax?

Pursuant to ORS 469.421(8)(a), the ODOE mandates each energy resource supplier pay to the department annually its share of an assessment "to fund the programs and activities of the council and the department." The annual assessment is commonly referred to as the ESA. ORS 469.421(8)(a) specifically provides:

> "***In addition to any other fees required by law, each energy resource supplier shall pay to the department annually its share of an assessment to fund*** the programs and ***activities of*** the council and ***the department***" (emphasis added).

ORS 469.421(8)(a) is nearly identical in language, function, and purpose to an earlier version of the ESA provided for in former ORS 469.420 (1981). Former ORS 469.420(4) provided:

> "***In addition to any other fees required by law, each energy resource supplier shall pay to the department annually*** commencing with the fiscal year beginning July 1, 1981, ***its share of an assessment to fund the activities of the department....***" (emphasis added).

In *Northwest Natural Gas Company v. Frank,* former ORS 469.420(4) was declared a tax against energy resource suppliers. *Northwest Natural Gas Company v. Frank*, 293 Or. 374, 376 (1982). In the last sentence of the opinion, the Court orderd the director to "amend his orders to assess ***taxes*** exclusively on a gross revenue basis." *Northwest Natural Gas. v. Frank*, 293 Or. at 384. After the opinion, by operation of law, former ORS 469.420 was automatically repealed and ORS 169.421 was enacted.

Respondents' comparison of the ESA set out in ORS 169.421(8)(a) to former ORS 756.310 is misplaced. The Ninth Circuit Court of Appeals held the "assessment" imposed on railroads by the Oregon Public Utility Commission ("OPUC") under former ORS 756.310 was a fee not a discriminatory tax for purposes of the federal Railroad Revitalization and Regulatory Act (4-R Act). *Union Pacific Railroad Company v. Public Utility Commission of the State of Oregon*, 899 F.2d 854, 856 (9th Cir. 1990). The assessment was paid directly to the OPUC and did not go into the general fund, generating no profit but devoted exclusively to defraying the costs of the regulatory program itself. *Id.* at 856-57. Similar to ORS 756.310, ORS 169.421(2) through (7) are devoted exclusively to defraying the costs of the regulatory programs. Specifically, subsection (7) provides:

> "When the actual ***costs of regulation*** incurred by the council and the department for the year, including that portion of the general regulation costs that have been allocated to a particular facility, are projected to exceed the annual fee for that facility, the director may issue an order revisiting the annual fee" (emphasis added).

However, subsection (8) is not devoted exclusively to defraying the costs of the regulatory programs, it is devoted to defraying the costs of the "programs and activities of the council and the department." By the clear language of the statute, the legislature intended for subsection (8) to cover costs other than regulatory costs.

The Oregon Supreme Court two-part test for determining whether a bill qualifies as a bill for raising revenue: (1) whether the bill collects or brings money into the treasury; and (2) whether the bill possesses the essential features of a bill levying a tax. *Bobo v. Kulongoski*, 338 Or. 111, 122, 107 P.3d 18, 24 (2005). The court finds ORS 169.421(8)(a) is a tax. The court also finds that ORS 169.421(8) correctly originated in the House of Representatives as HB 2259 and the amended HB 2807 (2013). Therefore, ORS 169.412 (8) does not violate the Oregon constitutional requirements for bills raising revenue.

(2) Is SB 5510 subject to Oregon constitutional requirements for bills raising revenue?

In 2015, the Oregon Legislative Assembly Regular Session passed Senate Bill 5510 that limits biennial expenditures from fees, moneys or other revenues, including Miscellaneous Receipts, but excluding lottery funds and federal funds, collected or received by State Department of Energy. *SB 5510,* 78th Gen. Assembly, Reg. Sess. (2015). Section 1 declares "$47,888,133 is established for the biennium beginning July 1, 2015, as the maximum limit for payment of expenses from fees...collected or received by the State Department of Energy" and Section 3 declares "$3,091,351 is established for the biennium beginning July 1, 2015, as the maximum limit for payment of expenses from federal funds collected or received by the State Department of Energy." *Id.*

The court finds SB 5510 is a budget bill for the 2015-17 biennium because it raises no revenue but authorizes expenditures. Also, SB 5510 transfers money between programs not "collect[ing] or bring[ing] money into the treasury." *Bobo v. Kulongoski*, 338 Or. at 122, 107 P.3d at 24. Therefore, SB 5510 is not subject to Oregon constitutional requirement that bills raising revenue originate in the House of Representatives.

(3) Did ODOE and Michael Kaplan follow statutory procedures before including the ESA in the agency's 2015-17 budget?

In 2013, the Oregon Legislative Assembly amended ORS 469.421 to include a new subsection regarding the ESA, subsection (8)(b) which provides:

> "Prior to filing an agency request budget under ORS 291.208. for purposes related to the compilation and preparation of the

> Governor's budget under ORS 291.216, the director shall determine the projected aggregate amount of revenue to be collected from energy resource suppliers under this subsection that will be necessary to fund the programs and activities of the council and the department for each fiscal year of the upcoming biennium. After making that determination, the director shall convene a **public meeting** with representatives of energy resource suppliers and other interested parties for the purpose of providing energy resource suppliers with a **full accounting** of:
>
> (A) The projected revenue needed to fund **each department program or activity**; and
>
> (B) The projected allocation of moneys derived from the assessment imposed under this subsection to **each department program or activity**."

ORS 469.421(8)(b) (emphases added).

In this matter, the ODOE convened four meetings in 2014, but none pursuant to the public meeting laws set out in ORS 192.630-640(1). The first meeting on May 19, 2014, called the "Energy Advisory Work Group", was an overall retrospective review of department policies, plans, and activities but did not specifically provide an accounting of the projected revenue needed or the projected allocation of the monies derived from the assessment. The second meeting on August 5, 2014 and the third meeting on August 7, 2014 were about budget information; however, both meetings lacked representatives of energy resource suppliers and other interested parties as mandated by ORS 469.421(8)(b). The fourth meeting on September 2, 2014, called the "Energy Advisory Work Group" was similar to the first meeting on May 19, 2014.

The first statutory violation the plaintiffs ask the court to consider is whether ODOE was required to and failed to hold a "public meeting" as that term is defined by ORS 192.630-640. Oregon's Public Meeting Laws define a "meeting" as "the convening of a governing body of a public body for which a quorum is required in order to make a decision or to deliberate toward a decision on any matter." ORS 192.610(5). Where no decision or deliberation takes place, there is no basis for calling an interaction a public meeting subject to the notice requirement. *See Handy v. Lane County*, 274 Or. App. 644, 661 (2015). A "governing body" is "any public body which consists of two or more members, with the authority to make decisions for or recommendations to the public body on policy or administration." ORS 192.610(3). A "decision" is "any determination, action, vote or final disposition upon a motion, proposal, resolution, order, ordinance or measure on which a vote of a governing body is required, at any meeting." ORS 192.610(1). The ESA meetings from 2014 were to provide energy resource suppliers with information. A meeting that facilitates information gathering is not, by itself a public meeting. *Harris v. Nordquist*, 96 Or. App. 19, 25 (1989). Thus, the 2014 meetings were not within the definition of requiring a governing body to make a decision but informational meetings pursuant to ORS 469.421(8).

Additionally, according to the *Attorney General's Public Records and Meetings Manual*, "The Public Meetings Law applies to the meetings of the governing body of public body… A 'public body' is also a board, department, commission, council, bureau, committee, subcommittee or advisory group." (*Attorney General's Public Records and Meetings Manual – Governing Bodies of Public Bodies* (November 2014) § II.B.1). More importantly, "a department headed by an individual public officer, such as the office of the State Treasurer, is not a 'governing body.'" *Id.* Here, the ODOE is a public body. The ODOE is headed by Michael Kaplan. As the director, Mr. Kaplan is not a governing body; therefore the Public Meetings Law is not applicable to ORS 469.421(8)(b).

The second violation the plaintiffs ask the court to consider is whether ODOE provided a "full accounting" to representatives of energy resource suppliers and other interested parties as required by the statute. On this point the court finds there is no genuine issue of material fact. Despite holding four separate meetings in 2014 and claims that a "full accounting" was provided, at no time did ODOE provide the full accounting required by ORS 469.421(8)(b). ODOE erroneously interpreted this provision of the law. ODOE failed to specifically provide the representatives of energy resource suppliers and other interested parties the projected revenue needed to fund each department program or activity and the projected allocation of monies derived from the assessment imposed under this subsection to each department program or activity. Therefore, the court finds ODOE failed to follow statutory procedures before including the ESA in the agency's 2015-17 budget. The court must assume that the legislature intended to give full effect to each statutory provision. ODOE's failure to provide the full accounting required by ORS 469.421(8)(b) deprived the representatives of energy resource suppliers and other interested parties of information the legislature intended them to have so that they could fully and effectively engage in the legislative process. There is no remedy that would adequately address ODOE's failure other than setting aside the Orders imposing the 2016 ESA.

## CONCLUSION

Plaintiffs' Motion for Summary Judgment is ***GRANTED*** in part. Respondents' Motion for Summary Judgment is ***DENIED***.

- The court declares the ESA is a tax.
- The court declares SB 5510 is not subject to Oregon constitutional requirements for bills raising revenue.
- The court declares the ODOE and Michael Kaplan did not follow statutory procedures before including the ESA in the agency's 2015-17 budget. Pursuant to ORS 183.484, the court finds that the ODOE erroneously interpreted a provision of law and that a correct interpretation compels the court to set aside the Orders imposing the 2016 ESA. Therefore, the ESA amounts paid by petitioners shall be refunded.
- Pursuant to ORS 183.484, the court lacks authority to issue an order enjoining collection of future ESAs.

Mr. Daniels shall prepare an appropriate order and judgment within 14 days for opposing counsel's review. There are no future dates set in this matter.

Sincerely,

Tracy A. Prall
Circuit Court Judge

TAP:cdh

**BEFORE THE PUBLIC UTILITY COMMISSION**

**OF OREGON**

**UE 335**

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

**EXHIBIT NO. AWEC/309**

**EXCERPT OF ODOE ESA POWERPOINT**

8/11/2016

## 2017-19 PROGRAM BUDGET ALLOCATIONS WITH PACKAGES

| | Base | Essential | Current Service Level | | Policy Option | ESA in Packages | | Agency Request Budget | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | Budget | Packages | CSL | CSL ESA | Packages | Pkg 070 | Pkg 110 | ARB | ARB ESA | FTE | FTE ESA |
| PUBLIC SCHOOLS | $1,114,826 | $10,806 | $1,125,632 | $174,526 | | | | $1,125,632 | $174,526 | 3.18 | 0.43 |
| PUBLIC BUILDINGS | $1,328,029 | $12,665 | $1,340,694 | $779,451 | $77,393 | | | $1,418,087 | $779,451 | 3.92 | 2.08 |
| ENERGY EFFICIENCY & CONSERVATION | $1,067,800 | $10,668 | $1,078,467 | $860,002 | ($77,393) | | ($77,393) | $1,001,074 | $782,609 | 2.37 | 1.83 |
| RENEWABLE TECHNOLOGIES | $2,060,564 | $166,552 | $2,227,116 | $2,198,753 | | | | $2,227,116 | $2,198,753 | 6.06 | 6.06 |
| TRANSPORTATION | $790,144 | $7,374 | $797,518 | $790,918 | ($164,480) | ($164,480) | | $633,039 | $626,439 | 1.33 | 1.33 |
| PLANNING, ECONOMICS & OTHER | $1,150,481 | $59,309 | $1,209,790 | $1,197,117 | | | | $1,209,790 | $1,197,117 | 3.09 | 3.09 |
| SELP LOAN ACTIVITY | $118,981,555 | $0 | $118,981,555 | | | | | $118,981,555 | $0 | | |
| SELP ADMINISTRATION | $2,688,081 | ($29,471) | $2,658,610 | | ($118,220) | | | $2,540,390 | $0 | 7.64 | |
| CLEAN ENERGY DEPLOYMENT FUND | $1,227,760 | $45,427 | $1,273,187 | | | | | $1,273,187 | $0 | | |
| EEAST DEBT SERVICES | $3,023,630 | $0 | $3,023,630 | | | | | $3,023,630 | $0 | | |
| ALT FUEL VEHICLE LOAN PROGRAM | $1,007,661 | $37,511 | $1,045,172 | | | | | $1,045,172 | $0 | | |
| ENERGY INCENTIVE PROGRAM | $4,904,490 | ($618,889) | $4,285,601 | | $2,000,000 | | | $6,285,601 | $0 | 4.81 | |
| BIOMASS TAX CREDITS | $406,172 | ($254,420) | $151,752 | $5,000 | | | | $151,752 | $5,000 | 0.59 | |
| BUSINESS ENERGY TAX CREDITS | $380,326 | ($215,391) | $164,935 | $2,000 | | | | $164,935 | $2,000 | 0.54 | |
| RESIDENTIAL ENERGY TAX CREDIT | $859,336 | ($130,476) | $728,859 | $447,837 | | | | $728,859 | $447,837 | 3.25 | 1.82 |
| STATE HEATING OIL WEATHERIZATION PROGRAM | $717,528 | $16,024 | $733,552 | | | | | $733,552 | $0 | 0.27 | |
| HANFORD OVERSIGHT | $1,903,256 | $15,933 | $1,919,190 | | | | | $1,919,190 | $0 | 3.80 | |
| EMERGENCY PREPAREDNESS | $783,136 | $6,610 | $789,746 | $173,149 | | | | $789,746 | $173,149 | 1.58 | 0.40 |
| RADIOACTIVE WASTE TRANSPORATION | $166,950 | $2,002 | $168,952 | | | | | $168,952 | $0 | 0.25 | |
| SITING CERTIFICATION | $3,346,109 | $67,288 | $3,413,397 | | | | | $3,413,397 | $0 | 4.46 | |
| SITE CERTFICATION MONITORING | $416,998 | $0 | $416,998 | | | | | $416,998 | $0 | 1.10 | |
| FEDERAL SITING COORDINATION | $5,829 | $0 | $5,829 | $5,829 | | | | $5,829 | $5,829 | 0.11 | 0.01 |
| ENERGY FACILITY SITING COUNCIL | $2,210,241 | $7,611 | $2,217,852 | $594,169 | $202,097 | | | $2,419,949 | $594,169 | 6.33 | 1.38 |
| DIRECTOR'S OFFICE | $4,839,713 | ($775,629) | $4,064,084 | $4,187,493 | $250,000 | | | $4,314,084 | $4,187,493 | 8.52 | 8.52 |
| CENTRAL SERVICES | $6,443,114 | $2,226,356 | $8,669,470 | | $819,073 | | | $9,488,543 | $0 | 28.45 | |
| OTHER ADMINISTRATIVE SERVICES | $729,410 | $1,075 | $730,485 | | $502,617 | | | $1,233,102 | $0 | 3.00 | |
| NON PROGRAM SPECIFIC FUNCTIONS | | | | | | | | | | | |
| Energy Planning & Innovation | $2,656,706 | $57,762 | $2,714,467 | $1,337,111 | ($1,147,890) | | | $1,566,577 | $1,337,111 | 3.30 | 3.30 |
| Energy Development Services | $2,191,747 | ($628,016) | $1,563,732 | $549,420 | ($118,220) | ($118,220) | | $1,445,512 | $431,200 | 0.73 | 0.73 |
| Nuclear Safety & Emergency Preparedness | $376,486 | ($47,525) | $328,961 | $176,855 | ($135,000) | | | $193,961 | $176,855 | 0.37 | 0.37 |
| Energy Facility Siting | | $0 | $0 | | | | | $0 | $0 | | |
| Administrative Service: | $1,667,023 | ($681,901) | $985,121 | | ($655,752) | | | $329,369 | $0 | | |
| Total (Includes indirects) | $169,445,102 | ($630,745) | $168,814,357 | $13,479,632 | $1,434,225 | ($282,700) | ($77,393) | $170,248,582 | $13,119,539 | 99.04 | 31.34 |