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January 13, 2022

Via Electronic Filing

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

Re: In the Matter of PORTLAND GENERAL ELECTRIC CO.
Request for a General Rate Revision.
Docket No. UE 394

Attention Filing Center:

Please find enclosed the redacted versions of the Rebuttal Testimony and Exhibits of Bradley G. Mullins (AWEC/300-303) and Dr. Lance D. Kaufman (AWEC/400-403) on behalf of the Alliance of Western Energy Consumers ("AWEC") in the above-referenced docket.

Please note that AWEC's Rebuttal Testimony and Exhibits contain Protected Information that is being handled in accordance with Order No. 21-206. The confidential portions of AWEC's filing have been encrypted with 7-zip software and are being transmitted electronically to the Commission and to Qualified Persons under Order No. 21-206.

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

Sincerely,

/s/ Jesse O. Gorsuch
Jesse O. Gorsuch

Enclosures

CERTIFICATE OF SERVICE

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

Dated at Portland, Oregon, this 13th day of January, 2022.

Sincerely,

/s/ Jesse O. Gorsuch
Jesse O. Gorsuch

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BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UE 394

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

REBUTTAL TESTIMONY OF

BRADLEY G. MULLINS

ON BEHALF OF

ALLIANCE OF WESTERN ENERGY CONSUMERS

(REDACTED)

January 13, 2022

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EXHIBIT LIST

I. INTRODUCTION AND SUMMARY

Q. ARE YOU THE SAME WITNESS THAT FILED OPENING TESTIMONY IN THIS MATTER?

A. Yes. I filed Opening Testimony in this docket on October 25, 2021, on behalf of the Alliance of Western Energy Consumers ("AWEC") addressing the proposed revenue requirement of Portland General Electric Company ("PGE" or "Company").

Q. PLEASE PROVIDE AN OVERVIEW OF THE REVENUE REQUIREMENT ITEMS RESOLVED IN THE THIRD PARTIAL STIPULATION.

A. Except for a list of enumerated issues, the Third Partial Stipulation resolves all revenue requirement issues in this docket.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. I respond to the Reply Testimony of PGE filed on December 2, 2021, and December 8, 2021 regarding issues not resolved by the Third Partial Stipulation. Specifically, I discuss: 1) the outstanding deferral balances associated with the 2020 Wildfires, the 2021 Ice Storm, and the 2020 Boardman retirement; 2) the Trojan Nuclear Decommissioning Trust ("Trojan NDT"); 3) Faraday Repowering; 4) Level III Storm Costs; and 5) Open Access Transmission Tariff ("OATT") Revenues. Witness Dr. Lance Kaufman will also be providing Rebuttal Testimony on behalf of AWEC on rate spread and rate design.

Q. PLEASE SUMMARIZE YOUR REBUTTAL TESTIMONY.

A. Based upon my review of PGE's Reply Testimony, I recommend the Public Utility Commission of Oregon ("Commission"):

- *Approve $15,000,000 of amortization expense associated with the UM 2115 2020 Wildfire and UM 2156 2021 Ice Storm Deferrals, subject to refund;*
- *Initiate a new consolidated proceeding to evaluate the UM 2115 2020 Wildfire Deferral, the UM 2156 2021 Ice Storm Deferral, and the UM 2119 Boardman Deferral;*

- *Require PGE to refund $3,312,642 through Schedule 143 in recognition of Department of Energy ("DOE") Reimbursements received for calendar year 2018, inclusive of interest;*
- *Reject PGE's proposal for a tariff rider related to the delayed and over-budget Faraday Repowering project;*
- *Reject PGE's request for a Level III Storm Tracker; and*
- *Accept PGE's Rebuttal proposal to maintain an OATT revenue deferral with no amortization in this case, with potential amortization considered in PGE's next AUT filing.*

II. OUTSTANDING DEFERRALS

Q. WHAT ARE THE OUTSTANDING DEFERRALS AT ISSUE IN THIS PROCEEDING?

A. Three sizable outstanding deferrals have been identified in this proceeding for potential amortization: the UM 2119 Boardman Deferral; the UM 2115 2020 Wildfire Deferral; and the UM 2156 2021 Ice Storm Deferral. In Joint Opening Testimony, AWEC and the Oregon Citizens' Utility Board ("CUB") recommended commencing amortization the UM 2119 Boardman Deferral over a three-year period. Further, in Opening Testimony, AWEC recommended the UM 2115 2020 Wildfire and UM 2156 2021 Ice Storm Deferrals also commence amortization in this proceeding over a three-year period, in a manner offsetting the impact of the UM 2119 Boardman Deferral.

Q. HOW DID PGE RESPOND TO THESE PROPOSALS?

A. PGE opposed both proposals. In PGE/2300, PGE opposed AWEC and CUB's recommendation to begin amortization of the UM 2119 Boardman Deferral, stating that "the deferral ignores the offset for PGE's much larger new capital investments subject to regulatory lag during the same period."[1/] Further, PGE opposed AWEC's request to begin offsetting

[1/] PGE/2300, Tooman–Batzler/13:7-8

amortization of the UM 2115 2020 Wildfire and UM 2156 2021 Ice Storm Deferrals, stating that it is "premature to address amortization of the Emergency Deferrals in this [general rate case ("GRC")]," prior to conducting an earnings test.[2/]

Q. WHAT ARE THE EXPECTED DEFERRAL BALANCES?

A. In Reply Testimony, PGE identified a correction to the tax expenses included in the Boardman revenue requirement calculation that AWEC and CUB had performed.[3/] This correction, which is detailed in Exhibit AWEC/301, results in a $108,109,463 balance as of May 1, 2022. Further, in response to AWEC Data Requests 309 and 313, PGE provided updated calculations of the balances accrued with respect to the UM 2115 2020 Wildfire Deferral and the UM 2156 2021 Ice Storm Deferral, which have increased materially relative to the amounts reported in response to Bench Request 2. The balances associated with each deferral can be seen in Table 1, below.

TABLE 1
Updated Outstanding Deferral Balances
Expected May 9, 2022 Balance – Whole Dollars

UM 2119 Boardman Deferral	AWEC/301		**(109,904,915)**
UM 2156 Ice Storm - O&M	AWEC DR 309	61,744,945	
UM 2156 Ice Storm - Capital	/	4,092,453	
UM 2156 Ice Storm Total			**65,837,398**
UM 2115 Wildfire - O&M	AWEC DR 313	57,393,713	
UM 2115 Wildfire - Capital	/	1,660,543	
UM 2115 Wildfire Total			**59,054,256**
Net Outstanding Deferrals			**14,986,738**

2/ PGE/2300, Tooman–Batzler/10:7.
3/ PGE/2300, Tooman–Batzler/15:11-13.

Q. WHY HAS THE WILDFIRE DEFERRAL BALANCE INCREASED SINCE PGE ISSUED BENCH REQUEST 2?

A. It can be noted from Table 1 that the UM 2115 2020 Wildfire Deferral balance increased from $32,069,107 in Bench Request 2 to $59,054,256 in AWEC Data Request 313. The 84% increase to the deferral balance since September appears to be caused by PGE adopting a more expansive view of what is included in this deferral. Since responding to Bench Request 2, PGE has accrued a significant amount of ongoing vegetation management costs to the deferral balance. As I discuss below, PGE may be using the UM 2115 deferral to capture all wildfire mitigation activities, not just those related to the 2020 wildfire events.

Q. GIVEN THESE UPDATED BALANCES, WHAT IS YOUR RECOMMENDATION?

A. Given that the UM 2115 2020 Wildfire and the UM 2156 2021 Ice Storm Deferral balances may now exceed the Boardman Deferral, AWEC recommends the Commission approve $15,000,000 in annual amortization related to those deferrals in this proceeding, subject to refund. The UM 2115 2020 Wildfire Deferral has already been approved. Further, in the Second Partial Stipulation, all parties agreed to support approval of the UM 2156 2021 Ice Storm Deferral, although there was no agreement on the ultimate amount to be deferred. Thus, there is no opposition to either of these deferrals and no valid reason to delay amortization at the expense of ratepayers in this docket. This amortization would occur through a separate schedule and be prorated between the deferrals with $ 7,092,658 applied to the UM 2115 2020 Wildfire Deferral and $7,907,342 applied to the UM 2156 2021 Ice Storm Deferral.

Q. HOW MUCH WILL IT COST RATEPAYERS IF THE COMMISSION DOES NOT APPROVE AMORTIZATION IN THIS CASE?

A. Prior to commencing amortization, Commission policy has been to apply the utility's cost of capital as the carrying charge for a deferral balance. If the Commission were to accept PGE's proposal to delay amortization, ratepayers will be subject to approximately $7,222,173 in additional carrying charges per year. Correspondingly, PGE will benefit by $7,222,173 per year due to the delay. Thus, the implication that delaying amortization mitigates the rate impact to ratepayers is disingenuous.

Q. IS IT PERMISSIBLE TO COMMENCE AMORTIZATION OF THE UM 2115 2020 WILDFIRE AND UM 2156 2021 ICE STORM DEFERRALS IN THIS DOCKET?

A. Yes. PGE claims that it would be impossible to consider the amounts in this docket because it has not yet been able to conduct an earnings review for 2021. I disagree. The form of an earnings review is not prescribed by statute. An earnings test, for instance, is already occurring through the revenue requirement calculation being evaluated by the parties in this docket. Further, the effects of an earnings test are also not specified in the statute. PGE, for instance, assumes that if the Company's earnings are above or below its authorized return on equity ("ROE"), a deferral in the Company's or customers' respective favor would not be authorized. My understanding is that an earnings test is generally subject to a range of reasonableness, and not meant to be a guarantee that the utility will earn up to, but not exceeding, its authorized ROE. Further, in this case, where there are offsetting deferrals with a comparable impact, the earnings test is less relevant, as the net impact of the deferred items did not have a significant impact on earnings. Finally, ORS 757.259(5) specifically provides the Commission with the authority to approve amortization subject to refund, which is what AWEC proposes.[4/]

[4/] See ORS § 757.259(5) ("…[A]mounts described in this section shall be allowed in rates only to the extent authorized by the commission in a proceeding under ORS 757.210 to change rates and upon review of the utility's earnings at the time of application to amortize the deferral. The commission may require that amortization of deferred amounts be subject to refund. The commission's final determination on the amount of deferrals allowable in the rates of the utility is subject to a finding by the commission that the amount was prudently incurred by the utility.").

Q. HOW DO YOU RECOMMEND THAT THE FINAL AMOUNT OF THESE DEFERRALS BE RESOLVED?

A. Given PGE's disincentive to begin amortizing the balances, I recommend that the Commission initiate a consolidated docket to review and establish final amortization schedules for all three of the outstanding deferrals. The level of amortization AWEC proposes in this case has been designed such that the residual impact of the three deferrals will potentially offset in that instance, if all amounts identified are approved (though as previously noted, AWEC does not necessarily agree with the amounts PGE identified for the Ice Storm and Wildfire deferrals). In a consolidated proceeding, parties would be free to raise whatever issues that may be relevant in establishing the final balances and amortization schedules associated with each of the deferred balances.

Q. HOW DO YOU RECOMMEND HANDLING THE BOARDMAN DEFERRAL?

A. AWEC strongly disagrees with the arguments put forth by PGE in its Rebuttal Testimony regarding the Boardman Deferral. Notwithstanding, given the potential carrying charge benefits that will accrue to ratepayers by delaying amortization, AWEC is willing to delay amortization of the Boardman Deferral until it can be evaluated in the consolidated docket proposed above. To be clear, however, by doing this, the Boardman Deferral will continue to earn interest at PGE's authorized cost of capital.

Q. WHAT ARGUMENT DID PGE PRESENT ON THE BOARDMAN DEFERRAL?

A. PGE argues that when considering the Boardman Deferral, it is necessary to consider regulatory lag associated with other capital placed into service over the same time frame.

Q. DO YOU AGREE WITH PGE?

A. No. Regulatory lag is irrelevant to the Boardman Deferral. Only a minor portion of the Boardman Deferral represents capital. Further, the other capital projects that PGE alleges is being subject to regulatory lag is not being deferred. Going back in time to consider those capital additions outside of a rate case would therefore constitute retroactive ratemaking.

Q. IS REGULATORY LAG THE ONLY FACTOR IMPACTING A UTILITY'S REVENUES?

A. No. Many factors influence a utility's overall revenues. Sales revenue growth, for example, is a factor that offsets regulatory lag, which PGE did not discuss in its analysis of the Boardman Deferral.

Q. HAVE PGE'S SALES INCREASED SINCE ITS LAST GENERAL RATE CASE?

A. Yes. Based on the sales forecast PGE provided in this case, PGE's sales have increased by approximately 8% since its 2019 General Rate Case. Those incremental revenues were not considered in PGE's objection to the Boardman Deferral.

Q. DO YOU AGREE IT IS PREFERENTIAL TO CONSIDER UTILITIES' EARNINGS ON A HOLISTIC BASIS?

A. As a general matter, AWEC does not disagree that it is preferable to consider a utility's revenues on a holistic basis in the context of a GRC, rather than through deferrals. That option, however, has been foreclosed with respect to the Boardman retirement because PGE did not file a GRC to capture factors potentially offsetting the impact of the retirement, such as regulatory lag. It is an asymmetric aspect of utility regulation that a utility has the option to file a rate case at any point in time, but may choose not to, depending on its financial circumstances. Ratepayers, on the other hand, do not have the same opportunity to compel PGE to file a rate case to capture the beneficial revenue requirement impacts of the Boardman retirement, and therefore, a deferral was the only option available to ensure that the benefits of the retirement are returned to ratepayers in a timely manner. Additionally, as the Commission is aware, PGE has numerous deferrals outstanding that would impose additional costs on customers. Forgoing the Boardman Deferral on the basis that it is outside of a holistic rate review would be one-sided in favor of the Company.

Q. DOES PGE'S POSITION ON THE BOARDMAN DEFERRAL CONTRADICT ITS POSITION ON ITS OTHER DEFERRALS?

A. Yes. In Opening Testimony, AWEC argued that the 2021 Ice Storm capital expenditures were not so significant as to warrant deferral.[5/] Based on AWEC's review, the storm capital amounts represented ordinary regulatory lag, which could be appropriately dealt with in the context of the rate case, rather than through a deferral. PGE responded that "[t]he point of deferring capital-related costs is that they are incremental to what is currently in base rates, but not what will be in the next GRC's base rates."[6/] Regulatory lag represents capital that is incremental to what is included in base rates, before inclusion in the utility's next GRC's base rates. Thus, PGE contradicts itself by arguing that regulatory lag is irrelevant to the 2021 Ice Storm Costs but should be considered in the context of the Boardman Deferral.

Q. DO YOU HAVE ANY OTHER ISSUES THAT YOU HAVE IDENTIFIED WITH RESPECT TO THE OUTSTANDING DEFERRALS?

A. Apart from the labor loadings and capital cost issues identified in my Opening Testimony, I am concerned that PGE is treating the UM 2115 2020 Wildfire Deferral as a wildfire mitigation tracking mechanism, rather than as a discrete deferral related to the 2020 Wildfire event. While the 2020 wildfire event occurred 18 months ago, PGE continues to accrue a large

5/ AWEC/100 Mullins, at 39:11-15.
6/ PGE/2300 Tooman – Batzler, at 12:19-20.

amount of vegetation management expenses, which may not be appropriately tied to the 2020 wildfire event. These costs appear to be related to PGE's ongoing wildfire mitigation activities, and not necessarily the 2020 wildfire event. This and other issues, however, would need to be investigated and considered in the context of the consolidated docket AWEC proposes.

III. TROJAN NDT

Q. WHAT ISSUE DID AWEC IDENTIFY WITH RESPECT TO THE TROJAN NDT IN OPENING TESTIMONY?

A. In Opening Testimony, AWEC demonstrated that PGE had underfunded the Trojan NDT relative to the amounts that it had received from ratepayers and the DOE. In PGE's Direct Testimony, it had "performed an analysis of the annual accrual, updated for the latest Trojan NDT balances, expected rate of return on trust assets, cost estimates, and other parameters", and found that "no change in the collection rate was needed."[7/] PGE's analysis was performed assuming underfunded amounts were not contributed to the Trojan NDT. Put another way, the catch-up contribution discussed below was not considered in PGE's funding analysis. Accordingly, since it would not impact the funding status of the Trojan NDT, AWEC recommended that the underfunded amounts be refunded to customers through Schedule 143.

Q. DID PGE ACKNOWLEDGE THAT IT HAD UNDERFUNDED THE TROJAN NDT?

A. Yes. PGE acknowledged that it made an error in the amounts it had contributed. PGE claimed that the underfunded amount was $6,609,990, rather than the $12,400,175 AWEC identified in Opening Testimony.[8/] The difference between the two figures was driven by the fact that PGE

[7/] PGE/200, Tooman–Batzler/16:20-22.
[8/] PGE/1900, Bekkedahl–Cristea/5:9-13.

had been applying the DOE funding directly to the Schedule 143 balancing account, rather than contributing the funds to the Trojan NDT and later making a refund to ratepayers through Schedule 143 from the Trojan NDT balance, as AWEC had assumed.

Q. HOW DID PGE EXPLAIN THIS LEVEL OF UNDERFUNDING?

A. PGE acknowledged that it neglected to contribute the funds in a timely manner. PGE states, however, that it had "always intended to add these funds to the trust and ha[d] no intention of retaining these amounts as AWEC asserts."[9/] Regardless, the fact is that at the time of PGE's Reply Testimony, the Company had failed to make these contributions, representing multiple years of DOE reimbursements and customer contributions.

Q. WHAT ACTIONS DID PGE TAKE AFTER FILING REBUTTAL TESTIMONY?

A. Following its Reply Testimony, PGE made a catch-up contribution to the Trojan NDT in the amount of $6,609,990 in an attempt to correct the contribution error that AWEC identified in Opening Testimony. Notably, AWEC had recommended refunding these amounts to ratepayers through Schedule 143, rather than contributing them to the Trojan NDT. Accordingly, PGE's actions might be viewed as obstructing AWEC's proposal.

Q. PLEASE PROVIDE AN OVERVIEW OF SCHEDULE 143.

A. Schedule 143 was initially implemented in Docket UE 283, PGE's 2014 GRC, with rates effective January 1, 2015.[10/] At that time, PGE had received about $44 million as partial compensation for storage expenses for the spent fuel in 2013 and anticipated receiving an additional $6 million from the DOE while the 2014 GRC was pending. In total, PGE received $50,004,086 from the DOE in 2013 and 2014, which it proposed to be refunded to customers

[9/] Id. at 6:22-7:1 (internal citations omitted).
[10/] Docket No. UE 283, Executive Summary of Portland General Electric, at 3 (Feb. 13, 2014).

through Schedule 143, originally over a two-year period beginning January 1, 2015. The 2013 refund was for costs incurred in the period prior to 2010. The 2014 refund was for costs incurred over the period 2010 through 2012. In that same filing, PGE also sought to refund to customers about $5.5 million related to state pollution tax credits for the Independent Spent Fuel Storage Installation ("ISFSI") at Trojan, which were also refunded through Schedule 143.

Q. HOW DID THE SCHEDULE 143 AMORTIZATION CHANGE IN THE 2015 GRC?

A. A driving factor of the 2015 GRC, Docket No. UE 294, was the impending in-service date of the Carty Generating Station ("Carty"). However, due to several factors, Carty's commercial operation date was delayed during the pendency of the GRC. In that case, parties agreed in a stipulation to allow PGE to file a tariff rider to include Carty in rates following the rate effective date. Given the treatment of Carty, ratepayers in the 2015 GRC were expecting a seven-month rate reduction in early 2016, followed by a rate increase once the Carty rider became effective in July of 2016. Accordingly, the parties to the 2015 GRC agreed to temporarily suspend the Schedule 143 refunds and spread the remaining refund amounts into 2017 for rate stability purposes.[11/]

Q. DID PGE RECEIVE FUNDS FROM THE DOE FOLLOWING THE 2013 AND 2014 REIMBURSEMENT PAYMENTS?

A. PGE will receive DOE reimbursements every year until the fuel is disposed. Reimbursements for claim periods 2013 and 2014 would have otherwise been received in 2015 and 2016. Those reimbursements, however, were offset by state pollution tax credits, which PGE had received for the spent fuel installation but already refunded to customers. Since PGE was already being compensated for some of the spent fuel storage installation costs through state tax credits, the

11/ Docket No. UE 294, Second Partial Stipulation, at 6-7 ¶ (1)(j)(iv) (Aug. 28, 2015).

DOE deducted the value of those tax credits from the amount that it reimbursed over that period. In 2017, however, things changed; the claim year 2015 DOE reimbursement received in 2017 exceeded the value of the tax credits, resulting in a new reimbursement funding being received by PGE.

Q. HOW DID PGE HANDLE THE 2015 DOE REIMBURSEMENT RECEIVED IN 2017?

A. PGE was initially unsure about how to handle the 2015 DOE reimbursements received in 2017. In email correspondence, PGE debated about whether to keep the funds and apply them to the Schedule 143 balancing account, or to contribute the funds to the Trojan NDT. As can be seen from the email correspondence in Confidential Exhibit AWEC/302, PGE ultimately decided that [redacted]", and instead applied the funds received from the DOE to the Schedule 143 balancing account. This decision was based on the language in Schedule 143, which stated the following:

> The Company will maintain balancing accounts to track the difference between the Trojan Nuclear Decommissioning Trust Fund refund and the ISFSI payments and the actual Schedule 143 revenues. This difference will accrue interest at the Commission-authorized rate for deferred accounts.[12]

Accordingly, by the time the initial $50,004,086 was set to be fully amortized at the end of 2017, PGE had approximately $3,620,327 of new funds accrued to the Schedule 143 balancing account, which PGE continued to refund through Schedule 143 in 2018. This treatment for the new DOE reimbursements was approved in Advice Filing 17-26, Docket ADV 650.

[12] Advice No. 14-03, Portland General Electric General Rate Revision UE 283, Original Sheet No. 143-3 (Feb. 13, 2014).

Q. WHAT HAPPENED IN 2019?

A. In December of 2018, PGE received an additional $2,797,147 in DOE reimbursements for claim year 2017 costs. PGE continued to record this reimbursement to the Schedule 143 balancing account and, like the earlier reimbursements, PGE proposed to continue amortizing the reimbursements to customers in calendar year 2019 through Advice Filing 18-19, Docket ADV 869.

Q. WAS THE 2019 SCHEDULE 143 REFUND AN ERROR?

A. No. PGE claims that the 2019 refund of calendar year 2017 DOE reimbursements received in 2018 through Schedule 143 was an error. That, however, is not true. This can be noted in Confidential Exhibit AWEC/302 and the associated Advice Filings. PGE had adopted a policy, which the Commission had accepted, to continue refunding the DOE reimbursements to ratepayers through Schedule 143, rather than contributing those funds to the Trojan NDT.

Q. DID PARTIES AGREE TO SUSPEND THE SCHEDULE 143 REFUNDS IN THE 2019 GRC?

A. No. In the 2019 GRC, Docket UE 335, the settlement did not address suspending the refund of DOE reimbursements in consideration of reducing the customer contributions to $1,900,000, nor on a retroactive basis. The reduced customer contributions were based on the issuance of a new Federal Energy Regulatory Commission ("FERC") license, which extended the life of the spent fuel storage facility through 2059.[13/] That being said, the modeling in this proceeding was premised on the contribution of the DOE reimbursements into the Trojan NDT rather than refunding those amounts to ratepayers. It is possible that PGE had made a similar assumption

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[13/] UE 335, PGE/200, Tooman–Espinoza/10:16-11:4.

when it accepted the $1,900,000 customer contribution level, although that was not documented as a condition of the 2019 GRC settlement.

Q. IF THE SCHEDULE 143 REFUNDS WERE TO HAVE BEEN SUSPENDED IN UE 335, WOULD THAT HAVE OCCURRED RETROACTIVELY?

A. No. Even if such a requirement were in the 2019 GRC settlement, such a change would have only implicated future claim years, and not prior claim years. The claim year 2017 DOE reimbursement was received in December 2018, before UE 335 rates went into effect, so the UE 335 stipulation would have no bearing on the Schedule 143 refund amount in 2019. This appeared to be PGE's position as well, as it requested to refund that amount through Advice Filing 18-19, which was well after the UE 335 stipulation.

Further, the claim year 2018 reimbursement of $2,960,544 also would not have been implicated by the 2019 GRC settlement because it relates to a claim year that preceded the UE 335 rate effective date, even though the receipt of those funds did not occur until December 2019.

If PGE's claim that the 2019 GRC stipulation resulted in the suspension of the Schedule 143 refund were true, that change would only apply to the DOE reimbursements beginning with claim year 2019, corresponding to the rate effective date in the 2019 GRC.

Q. SO WHAT WAS THE ERROR THAT OCCURRED?

A. In January 2019, due to some apparent miscommunication amongst PGE's rates and accounting departments, the Company incorrectly contributed the 2018 DOE reimbursement amount of $2,797,147 into the Trojan NDT, even though the refund amount was also being refunded to ratepayers through Advice Filing 18-19. In the email correspondence provided in

AWEC/302, it is apparent that this trust contribution created alarm and disarray from an accounting perspective.

Q. HOW DID PGE ATTEMPT TO CORRECT ITS ERROR?

A. Rather than seeking Commission and stakeholder guidance on the matter, PGE attempted to unilaterally offset the error by not contributing the 2020 customer contributions to the Trojan NDT which were being recovered in rates. PGE also stopped contributing the DOE reimbursements to the Trojan NDT. While there might have been an intention to resume those contributions, no action was taken by PGE for approximately two years. PGE simply stopped contributing anything to the Trojan NDT until AWEC identified the funding issues in Opening Testimony.

Q. WAS PGE CORRECT TO SUSPEND SCHEDULE 143 IN 2020?

A. No. While it was not documented in the settlement, AWEC does not necessarily disagree that it is appropriate to contribute the DOE Reimbursements directly to the Trojan NDT in connection with the reduced customer contributions that occurred in the 2019 GRC. That change, however, should only have occurred on a going-forward basis. In December 2019, PGE received $2,960,544 in DOE reimbursements for claim year 2018. Since those amounts were for a claim year that preceded the reduction to customer contributions agreed to in the 2019 GRC, that reimbursement should have been refunded to customers through Schedule 143, in contrast to being contributed to the Trojan NDT. PGE, however, did neither of those things. Rather, PGE kept the claim year 2018 DOE reimbursement and did not make any contribution until the end of 2021, after AWEC filed its testimony requesting that the amount be refunded to ratepayers.

Q. DO YOU AGREE WITH PGE'S CORRECTIVE CONTRIBUTION?

A. No. There are two problems with PGE's corrective contribution. First, as noted above, it incorrectly assumes that the 2018 claim year reimbursement of $2,960,544 was supposed to be contributed to the Trojan NDT. As discussed above, that amount was supposed to be refunded to ratepayers. Second, the contribution ignores approximately $352,098 in interest that remains in the Schedule 143 balancing account.

Q. WHAT DO YOU RECOMMEND?

A. AWEC recommends that PGE refund $3,312,642 to ratepayers over a 12-month period through Schedule 143, representing the 2018 claim year reimbursements and the residual interest balance. Since the claim year 2018 reimbursement was incorrectly submitted to the trust, AWEC recommends PGE either withdraw the funds from the trust, or offset the amount against future customer contributions, as it did with the 2017 claim year reimbursement.

IV. FARADAY TRACKING MECHANISM

Q. WHAT DID PGE INITIALLY PROPOSE WITH RESPECT TO THE FARADAY REPOWERING PROJECT?

A. In Direct Testimony, PGE proposed to include the Faraday Repowering project as a pro forma plant addition in revenue requirement based on an expected in-service date of March 2022.[14] The total project capital, including Allowance for Funds Used During Construction ("AFUDC"), was expected to be $119,384,638. Based on PGE's response to Staff Data Request 584, Attachment A, the initial project decision was based on an expected capital cost of [redacted], including AFUDC and overheads, along with an expected in-service date of

[14] PGE/700, Jenkins–Cristea/4:5-5:23.

[redacted]. Thus, the project is already more than 100% over budget and with an expected delay of approximately [redacted].

Q. WHAT DID AWEC RECOMMEND?

A. AWEC's review of the supporting documentation underlying the Faraday Repowering project indicated that it was highly unlikely that the project would be in service by the rate effective date of this proceeding. Accordingly, AWEC recommended that the Faraday Repowering project be removed from revenue requirement and not be considered as pro forma plant addition in this docket. Notwithstanding major concerns about the prudence of the project, AWEC recommended that the Faraday Repowering project not be evaluated in this docket, as there is insufficient information available at this time to do so. Specifically, even further project delays and budget overages are expected and there is little certainty at this time regarding timing or expected total cost of the project. Thus, there are clearly valid outstanding questions regarding the prudence of the project that cannot be fully evaluated until the project is completed.

Q. WHAT DID PGE PROPOSE IN REPLY TESTIMONY?

A. PGE acknowledged that the Faraday Repowering project would not be in service by the rate effective date in this case. PGE stated that "the most recent update to the project schedule provides for a fourth quarter 2022, in-service date."[15/] To accommodate the late in-service date, PGE requests that the Commission adopt a tariff rider, presumably similar to the Carty rider approved in Docket UE 294.

15/ PGE/1900, Bekkedahl–Cristea/13:16-17.

Q. DID PGE IDENTIFY THE UPDATED BUDGET AND IN SERVICE DATE?

A. No. PGE did not provide an updated budget estimate. Further, while PGE refers to a fourth quarter 2022 in-service date, it is unclear if that date may be further pushed out in future project revisions.

Q. GIVEN THE LACK OF INFORMATION, DO YOU CONTINUE TO RECOMMEND THE COMMISSION NOT CONSIDER FARADAY IN THIS DOCKET?

A. Yes. Until the Faraday Repowering project has been placed into service, the scope of the delays and the magnitude of the budget overages are unknown. Those are critical factors in evaluating the prudence of the Faraday Repowering project. If, for example, spring floods in 2022 cause yet another round of catastrophic damage to the construction site, further delays may occur. Such potential impacts are unknown at this time.

Q. IS FARADAY ANALOGOUS TO CARTY?

A. No. Carty was a major power plant with a nominal capacity of 450 MW. Carty was selected in PGE's 2009 Integrated Resource Plan ("IRP") and underwent a rigorous request for proposal ("RFP") process, reviewed by all parties and the Commission. At the time Carty was put into rates, it had been studied by stakeholders and the Commission for approximately 7 years; there were no questions regarding the decision to build the facility, in light of other alternatives. Comparatively, the Faraday Repowering project results in a mere 1.8 aMW of incremental capacity to the system and was not considered in the IRP nor an RFP process. Thus, the fundamental question of whether PGE acted prudently in constructing the project remains at issue.

Further, unlike in this case, the Carty rider was approved through a stipulation in the 2015 GRC. In the stipulation, PGE made a firm commitment to stakeholders that it would not exceed its initial budget and that the facility would be in service by July of 2016, the originally planned in service date. However, in this case, the Faraday Repowering project is already 100% over budget and is projected to be further over budget given the most recent round of project delays. Additionally, the Faraday Repowering project is already several years behind schedule and there is little certainty regarding the in-service date of the facility. While PGE believes the in-service date will be in the fourth quarter of 2022, the lack of concrete progress on the project suggests that the in-service date will be even later than the fourth quarter of 2022.

Q. IS IT POSSIBLE FOR THE COMMISSION TO PRE-APPROVE THE RIDER THAT PGE IS SEEKING?

A. No. The Carty rider was a unique situation that was the result of a stipulation amongst all parties to the case with carefully crafted requirements and ratepayer protections. If, in the face of party objections, the Commission were to approve a rider for the Faraday Repowering project, it would represent a blank check to the utility with little to no assurance regarding the final project costs or estimates. Rather, a more reasonable way to proceed in this docket is to treat the Faraday Repowering project like any other capital addition and consider it in the context of PGE's next GRC, where the final project, including the Company's decision to construct the project, can be fully evaluated for prudence. At a minimum, if the Commission allows PGE some form of special ratemaking proceeding for the Faraday Repowering project, it should also allow parties to the proceeding to raise any relevant issues that may impact PGE's overall revenue requirement, not just the Faraday Repowering project.

V. LEVEL III STORM DEFERRAL MECHANISM

Q. WHAT DID PGE PROPOSE IN DIRECT TESTIMONY REGARDING LEVEL III STORM COSTS?

A. PGE proposed a balancing account where base prices would continue to include the 10-year average of Level III storm costs, but these amounts would be held in a reserve account that would be allowed to go negative in years where restoration costs exceed the reserve amount. PGE would assume 10% of the costs of any negative balance, with customers responsible for the other 90%. PGE would also refund or recover any positive or negative balance that exceeds $12 million.

Q. HOW DID AWEC RESPOND TO PGE'S PROPOSED MECHANISM?

A. In Opening Testimony, AWEC opposed the Level III storm mechanism. The Commission had already rejected PGE's proposal for such a mechanism in PGE's most recent GRC, Docket No. UE 335. AWEC noted that PGE has not provided any substantially new information that warrants changing Commission precedent, other than broad references to the impacts of climate change. AWEC further noted that the current methodology has allowed PGE to sufficiently recover its storm costs, including the opportunity to defer costs associated with extraordinary events, such as the 2021 Ice Storm. Thus, there is no valid reason to make a systematic change to the way Level III storm costs are recovered in this case.

Q. HOW DID PGE RESPOND?

A. PGE responded by stating that it has experienced a greater variety of Level III storm events and with greater intensity. PGE performs an analysis of storm costs over the period 1996 through 2021 in an attempt to demonstrate this point.

Q. IS CLIMATE CHANGE A REASON TO CHANGE THE CURRENT MECHANISM?

A. No. Although climate change in and of itself is certainly relevant and is likely contributing to changes in storm patterns, it has been affecting the weather for many years now. Accordingly, the current methodology, which relies on a ten year-average of Level III storm costs escalated for inflation, is well suited to capture the impacts of climate change in the rolling calculation. The accelerating effects of climate change on storms, for example, cannot readily be isolated to a period of less than 10 years, rendering the 10-year average inadequate. The devastating effects of Hurricane Sandy, for example, occurred in 2012 and were largely attributed to climate change.

Q. IS PGE'S ANALYSIS OF STORM COSTS OVER THE PERIOD 1996 THROUGH 2021 A REASON FOR THE COMMISSION TO CHANGE ITS PRECEDENT?

A. No. PGE's analysis demonstrates that the distribution of Level III storm costs has been relatively uniform over time. PGE's analysis, however, is fundamentally flawed because it ignores over half of the cost associated with the 1995-1996 ice storms. PGE starts its analysis in 1996 and ignores $10,000,000 in costs that PGE had attributed to 1995 in connection with these events. This cost was provided in PGE's response to AWEC Data Request 42 in Docket UE 335. I have included the attachment to that response, along with an updated version of PGE's analysis that includes the full impact of the 1995-1996 storms, in Exhibit AWEC/303.

Q. WHAT DOES YOUR ANALYSIS SHOW?

A. Over the first half of the period 1996 to 2021, between of 1995 to mid-2008, Level III storm costs represented 52.5% of the total. Over the second half of the 1996 to 2021 period, mid-2008 through 2021, Level III storm costs represented 47.5% of the total. Thus, Level III storm costs actually declined over the 27-year period.

Further, even if one were to accept PGE's analysis, and exclude 1995 storm costs, the distribution of storm costs over the period 1996 through 2021 is not so significant to warrant a change in Commission precedent. Over the period 1996 through 2008, the first half of the 26-year period, Level III storm costs represented 45.8% of the total. Over the period 2009 through 2021, the second half of the 26-year period, Level III storm costs represented 54.2% of the total. Thus, even with its flaws, only slightly more than half of the Level III storm costs occurred in the second half of the 26-year period in PGE's analysis.

Further, a slight increase in storm costs over time is expected, since more storms will qualify for Level III treatment due to inflation and as a result of the expansion to PGE's service area. With more equipment in service, more needs to be repaired in the context of a Level III storm. These impacts, however, are fairly captured in the context of the 10-year average.

Q. PLEASE SUMMARIZE YOUR RECOMMENDATION.

A. The current Level III storm methodology already fairly considers the effects of climate change. PGE presents no compelling reason to make a change in this proceeding. Therefore, AWEC recommends that the Commission reject PGE's proposed balancing account and retain the existing Level III Storm mechanism.

VI. OATT REVENUE DEFERRAL

Q. WHAT DID PGE PROPOSE WITH RESPECT TO OATT REVENUES IN DIRECT TESTIMONY?

A. In Direct Testimony, PGE noted that it expects to file a transmission rate case but proposed to exclude any incremental revenues associated with the transmission rate case from revenue requirement in this proceeding.[16] Notwithstanding, PGE proposed a deferral, which would "1) be subject to an automatic adjustment clause; 2) be effective as specified in the applicable FERC order; and 3) continue until PGE's next GRC (with the deferral to be re-authorized annually), at which time [PGE] will incorporate the updated transmission revenue in the forecast for Other Revenue."[17]

Q. WHAT DID AWEC RECOMMEND IN OPENING TESTIMONY REGARDING OATT REVENUES?

A. AWEC recommended that the incremental revenues associated with PGE's ongoing FERC rate case be considered in the other revenue forecast in this docket based on the revenue increase that PGE requested in its transmission rate case.

Q. HOW DID PGE RESPOND?

A. PGE opposed AWEC's recommendation to return incremental revenues in this docket, stating that "the impacts of the FERC case will not be known by the time this…GRC…is resolved."[18]

Q. DO YOU AGREE WITH PGE?

A. Given the magnitude of the revenue requirement increase in the Third-Partial Stipulation, AWEC is willing to support PGE's recommendation to defer the incremental OATT revenues and not consider them in this docket. As PGE notes, the resolution of the OATT rate case is still uncertain and it would not be preferable at this time to provide a credit to ratepayers, only to have to refund the amounts later.

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[16] PGE/200, Tooman – Batzler/10:8-11:22.
[17] Id. at 11:22-25.
[18] PGE/1400, Tooman–Batzler/11:3-4.

Q. DO YOU RECOMMEND CONSIDERING THE OATT REVENUES IN A FUTURE DOCKET?

A. Yes. PGE has proposed establishing an automatic adjustment clause to account for the OATT transmission rate deferral. AWEC supports this approach. Notwithstanding, AWEC recommends that depending on the status of the transmission rate case, amortization of the incremental OATT revenues be reviewed at least annually and considered in conjunction with PGE's Annual Update Tariff or GRC filings.

Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes.

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UE 394

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

EXHIBIT AWEC/301

UPDATED BOARDMAN DEFERRAL BALANCE CALCULATION

1	Depreciation Expense	AWEC DR 32	29,209,000
2	Labor O&M	|	11,674,504
3	Non-Labor O&M	\	17,645,453
4	Property Taxes	([8]+[9])*1.45%	522,387
5	Tax Benefit of Int.	-[12]*[18]*50%*[20]	(388,421)
6	Tax Expense	Sum([1]:[4])*[20]	(16,033,217)
7	**Net Operating Income**	Sum([1]:[6])	**42,629,706**
8	Gross Plant	AWEC DR 32	515,948,390
9	Accumulated Depreciation	|	(479,921,727)
10	Accumulated Deferred Tax	|	14,434,882
11	Fuel Stock	\	5,639,588
12	**Total Rate Base**	Sum([8]:[11])	**56,101,133**
13	Required Return	[12]*[19]	4,095,383
14	Post-Tax Rev. Req.	[13]+[7]	46,725,088
15	**Pre-Tax Rev. Req**	[14]/[21]	**66,261,494**
16	Cost of Capital:		
17	Equity	UE 335 1st Stlmnt.	9.50%
18	Debt	|	5.10%
19	Cost of Capital @ 50/50	\	7.30%
20	Tax Rate	UE 335 Wrkpprs.	0.2715
21	Revenue Conversion Factor	\	0.7052

Calculation of Boardman Deferral and Amortization

Month	Beg.Balance	Accural	Amortization	Interest Rate	Interest	Ending Balance
10/1/2020	-	2,760,896		7.30%	8,398	2,769,293
11/1/2020	2,769,293	5,521,791		7.30%	33,642	8,324,726
12/1/2020	8,324,726	5,521,791		7.30%	67,438	13,913,955
1/1/2021	13,913,955	5,521,791		7.30%	101,439	19,537,185
2/1/2021	19,537,185	5,521,791		7.30%	135,647	25,194,623
3/1/2021	25,194,623	5,521,791		7.30%	170,063	30,886,477
4/1/2021	30,886,477	5,521,791		7.30%	204,688	36,612,956
5/1/2021	36,612,956	5,521,791		7.30%	239,524	42,374,271
6/1/2021	42,374,271	5,521,791		7.30%	274,572	48,170,635
7/1/2021	48,170,635	5,521,791		7.30%	309,833	54,002,259
8/1/2021	54,002,259	5,521,791		7.30%	345,309	59,869,360
9/1/2021	59,869,360	5,521,791		7.30%	381,001	65,772,152
10/1/2021	65,772,152	5,521,791		7.30%	416,909	71,710,852
11/1/2021	71,710,852	5,521,791		7.30%	453,036	77,685,680
12/1/2021	77,685,680	5,521,791		7.30%	489,383	83,696,854
1/1/2022	83,696,854	5,521,791		7.30%	525,951	89,744,597
2/1/2022	89,744,597	5,521,791		7.30%	562,742	95,829,130
3/1/2022	95,829,130	5,521,791		7.30%	599,756	101,950,677
4/1/2022	101,950,677	5,521,791		7.30%	636,995	108,109,463
5/1/2022	108,109,463	1,603,101		7.30%	192,351	109,904,915
5/9/2022	**109,904,915**		-			

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UE 394

In the Matters of	)
	)
PORTLAND GENERAL ELECTRIC COMPANY,	)
	)
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Request for a General Rate Revision.	)
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EXHIBIT AWEC/302

TROJAN NDT EMAIL CORRESPONDENCE

(REDACTED)

Exhibit AWEC/302 includes Protected Information Subject to Order No. 21-206 and has been redacted in its entirety.

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

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PORTLAND GENERAL ELECTRIC COMPANY,	)
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EXHIBIT AWEC/303

STORM COST ANALYSIS INCLUDING 1995-1996 ICE STORM

Level III Storm Cost Analysis 1995 -2021

Year	Nominal Storm Costs	Inflation Rate	Inflation Index	2021$ Storm Costs
1995	10,000,000	2.10%	1.02	17,328,477
1996	5,880,000	2.95%	1.05	9,897,178
1997	-	2.29%	1.08	-
1998	2,438,440	1.56%	1.09	3,950,847
1999	-	2.21%	1.12	-
2000	-	3.36%	1.15	-
2001	-	2.85%	1.19	-
2002	-	1.58%	1.21	-
2003	-	2.28%	1.23	-
2004	2,976,869	2.66%	1.27	4,161,861
2005	-	3.37%	1.31	-
2006	3,869,486	3.22%	1.35	5,070,172
2007	886,621	2.87%	1.39	1,129,324
2008	5,936,058	3.81%	1.44	7,283,492
2009	2,106,514	-0.32%	1.44	2,592,972
2010	-	1.64%	1.46	-
2011	-	3.14%	1.51	-
2012	-	2.07%	1.54	-
2013	-	1.47%	1.56	-
2014	5,623,875	1.62%	1.59	6,274,258
2015	5,161,601	0.12%	1.59	5,751,622
2016	4,504,081	1.26%	1.61	4,956,489
2017	11,351,424	2.14%	1.64	12,229,887
2018	-	2.44%	1.68	-
2019	1,772,198	1.81%	1.71	1,830,730
2020	-	1.00%	1.73	-
2021	3,594,072	2.28%	1.77	3,594,072
Total	66,101,239			86,051,381

UE 355 AWEC DR 042

PGE Major Storms, 1995-2016

Year	Nominal Costs	Notes
1995	$ 10,000,000	Prior to 2010, PGE had property insurance that covered its transmission and distribution system. Under the insurance policy, there was no determination of storm by level. If a storm exceeded the deductible of $1,000,000, a claim was made. Storm costs in 2007 are less than $1,000,000 because the costs in 2007 are attributable to the December 2006 windstorm.
1996	$ 5,880,000	
1997	N/A	
1998	$ 2,438,440	
1999	N/A	
2000	N/A	
2001	N/A	
2002	N/A	
2003	N/A	
2004	$ 2,976,869	
2005	N/A	
2006	$ 3,869,486	
2007	$ 886,621	
2008	$ 5,936,058	
2009	$ 2,106,514	
2010	N/A	No Level III Storms in 2010
2011	N/A	No Level III Storms in 2011
2012	N/A	No Level III Storms in 2012
2013	N/A	No Level III Storms in 2013
2014	$ 5,623,875	
2015	$ 5,161,513	
2016	$ 4,615,060	2016 storm costs have been since from PGE's initial filing.

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UE 394

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

REBUTTAL TESTIMONY OF

DR. LANCE D. KAUFMAN

ON BEHALF OF

ALLIANCE OF WESTERN ENERGY CONSUMERS

(REDACTED)

January 13, 2022

TABLE OF CONTENTS

EXHIBIT LIST

I. INTRODUCTION AND SUMMARY

Q. PLEASE STATE YOUR NAME AND OCCUPATION.

A. My name is Dr. Lance D. Kaufman. My witness qualification statement can be found at Exhibit AWEC/201.

Q. ARE YOU THE SAME LANCE KAUFMAN THAT FILED OPENING TESTIMONY IN THIS CASE?

A. Yes.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. I discuss my response to Intervenor Opening Testimony and PGE's Reply Testimony as it relates to rate-spread, rate-design, and other issues raised in my Opening Testimony.

Q. PLEASE SUMMARIZE YOUR PROPOSALS.

A. I am sponsoring four non-revenue requirement proposals:

Rate spread Customer Marginal Cost: PGE's Reply Testimony notes that my recommended changes to other consumer cost allocations included allocation of indirect costs. However, in discovery PGE agreed that the majority of my proposed re-allocations were appropriate. I maintain my original recommendation with three changes to specific accounts in response to PGE's concerns.

Rate spread Generation Marginal Cost: AWEC and Staff made several generation marginal cost proposals. In reply, PGE opposed all changes except updating fuel. I address each party's concerns with each proposal and maintain my original recommendations. I also recommend that PGE's 2019 average planning reserve margin of 16 percent be used in modeling capacity costs.

Schedule 90 Subtransmission Rate: In Opening Testimony, I proposed a subtransmission rate for Schedule 90 to mirror Schedule 89. In reply, PGE disputed that a subtransmission rate should be available for Schedule 90. I maintain my original recommendation to add a subtransmission rate.

Nonbypassable Charges: I continue to recommend that the Public Utility Commission of Oregon ("Commission") reject PGE's proposals to assign certain costs to direct access customers.

II. OTHER CONSUMER COSTS

Q. WHAT ISSUE DID YOU RAISE REGARDING OTHER CONSUMER COSTS IN YOUR OPENING TESTIMONY?

A. I noted that PGE modified its unbundling of costs, resulting in a shift of substantial costs from Billing to Other Consumer functional categories.[1/] PGE's marginal cost model did not get appropriately updated to reflect the changes in the unbundling methodology. I recommended that additional costs be included in PGE's other consumer marginal cost model. In PGE's Reply Testimony, PGE stated that the costs that I added to the other consumer costs should either be included in billing[2/] or excluded from allocation due to being indirect costs.[3/]

Q. DOES PGE STILL MAINTAIN ITS REPLY TESTIMONY POSITION?

A. No. PGE appears to have modified its position on these costs. In AWEC data requests ("DRs") 336, 337 and 338, AWEC asked PGE to clarify its position regarding the discrepancy between unbundling costs to Other Consumer while allocating these costs as billing costs. For most of these costs, PGE stated that it "inadvertently missed the inclusion of a number of direct costs…in its marginal cost study….[A] large number of the costs [listed in the DR] should be allocated to Other Consumer but are currently allocated to Billing."[4/] Accordingly, PGE appears to now support allocating direct costs unbundled to other consumer functions within the Other Consumer marginal cost model.[5/]

1/ Costs unbundled to Billing are costs related to calculating and sending customer bills. Costs unbundled to Other Consumer are miscellaneous consumer costs that relate to miscellaneous consumer services, such as call centers and low-income assistance.

2/ PGE / 2200 Macfarlane – Tang / 6:21-23.

3/ Id. at 6:23-7:3.

4/ AWEC/401 (PGE Response to AWEC DR 338, at 3); see also, AWEC/401 (PGE Resp. to AWEC DR 336).

5/ AWEC/401 (PGE Response to AWEC Data Requests 336, 337 and 338).

Q. WHAT ARE YOUR RECOMMENDATIONS GIVEN PGE'S UPDATED POSITION?

A. I maintain my original recommendations, with the following minor changes:

1. Modify the allocation basis of Department 881: Government Affairs Account 9050001 from number of customers to number of residential customers. PGE's response to AWEC DR 337 indicates that these costs are directly related to low income and special needs (i.e. customers with medical certificates).[6/]
2. Remove 979: Information Tech Transfers Account 9030001 from allocation, accepting PGE's assertion that these costs are indirect.[7/]
3. Remove 979: Information Tech Transfers Account 9080001 from allocation, accepting PGE's assertion that these costs are indirect.[8/]

Q. WHAT IS THE IMPACT OF YOUR RECOMMENDED CHANGES?

A. Relative to my Opening Testimony, the three changes identified above increase costs allocated to large schedules and reduce costs allocated to smaller customers. AWEC Exhibit 402, page 4, summarizes my recommended changes related to other customer costs.

III. GENERATION MARGINAL COST

Q. PLEASE SUMMARIZE THE RECOMMENDATIONS MADE BY PARTIES REGARDING GENERATION MARGINAL COST.

A. In my Opening Testimony I recommend two changes to PGE's generation marginal cost study to account for the impacts of Oregon House Bill ("HB") 2021 and the overall migration to non-emitting generation:

6/ AWEC/401 (PGE Response to AWEC Data Requests 337).
7/ AWEC/401 (PGE Response to AWEC Data Requests 338, part n).
8/ AWEC/401 (PGE Response to AWEC Data Requests 338, part w).

1. Reflect capacity value of wind in a parallel manner to the treatment of capacity value for a combined cycle combustion turbine ("CCCT").
2. Include a weighting of emitting and non-emitting capacity resources for capacity cost, parallel to the treatment of energy costs.

Staff's Opening Testimony also included recommendations for generation marginal cost:

1. Reduce the reserve margin from 12 to 10 percent;
2. Net out energy sales to reduce the cost of capacity;
3. Re-adopt Oregon Citizens' Utility Board's ("CUB's") UE 335 recommendation to allocate 10 percent of smart grid costs to generation; and
4. Incorporate the updated (higher) natural gas prices.

PGE's Reply Testimony responds to both AWEC and Staff's Opening Testimony on these issues.

Q. DID CUB RAISE ANY ISSUES ASSOCIATED WITH THE MARGINAL COST STUDY OR RATE SPREAD?

A. No. CUB identified no concerns with PGE's marginal cost study and stated that it would address rate spread, if at all, in its rebuttal testimony.[9/]

Q. IS THERE GENERAL GUIDANCE ON COST ALLOCATIONS AND COST OF SERVICE STUDIES THAT CAN GUIDE THE COMMISSION ON THESE ISSUES?

A. Yes. The Regulatory Assistance Project ("RAP") gives the following approach for modeling the long-run marginal cost of generation: "[c]ost of constructing and operating an optimal mix of new generating facilities at today's costs to serve the current customer requirements."[10/]

9/ CUB/200, Gehrke/23:4-9.

10/ Lazar, J., Smart Rate Design for a Smart Future, Montpelier, VT: Regulatory Assistance Project, at Appendix A:A-2 (July 2015) available at: https://www.raponline.org/wp-content/uploads/2016/05/appendix-a-smart-rate-design-2015-aug-31.pdf.

This means that long-run marginal generation costs should be modeled as if PGE's existing generation resources did not exist and PGE had the ability to construct all new facilities from scratch.

a. <u>Reflect Capacity Value of Wind in Energy Cost</u>

Q. WHAT ISSUE DID YOU RAISE IN OPENING TESTIMONY REGARDING CAPACITY VALUE OF WIND?

A. PGE's model calculates energy value by weighting the energy costs associated with a CCCT and the energy cost associated with wind generation. For the CCCT, PGE reduces energy costs to account for capacity contribution of a CCCT. For the wind component however, PGE's model makes no adjustment to account for capacity value. I recommended that the capacity value of wind be modeled at the effective load carrying capacity ("ELCC") used in PGE's Integrated Resource Plan ("IRP") and removed from the levelized cost of energy in the marginal cost study to avoid double counting the capacity cost through both the marginal cost of capacity and the marginal cost of energy.

Q. HOW DOES PGE RESPOND TO YOUR PROPOSAL?

A. PGE states that the capacity value of wind varies depending on the number of renewables on the system and asserts that "[g]iven the unpredictability of the wind blowing, it's safe to say that wind provides mostly energy."[11/] PGE's Reply Testimony does not dispute that wind offers some capacity value. PGE offered no argument for why the capacity value of wind should be treated differently from the capacity value of a CCCT in the marginal cost study. PGE further did not dispute that, to the extent there is capacity associated with wind, it would be double counted if not removed from the levelized cost of energy.

11/ PGE / 2200 Macfarlane – Tang / 5:15-16.

Q. DOES PGE CONSIDER CAPACITY VALUE OF WIND WHEN MAKING PLANNING DECISIONS?

A. Yes. In each IRP, PGE carefully evaluates the capacity contribution of wind and allows wind to meet capacity needs. PGE admits that the 2019 IRP Update provides a reasonable representation of the capacity contribution of wind.[12/] The 2019 IRP Update Figure 15 shows the ELCC of over 40 percent. This is a material capacity contribution.

Q. HOW DOES THE CURRENT ELCC ESTIMATE FOR WIND COMPARE TO THE ESTIMATE USED IN YOUR OPENING TESTIMONY?

A. The analysis in my Opening Testimony assumed an ELCC of 37% based on the 2019 IRP, which is lower than the 2019 IRP Update's estimate.

Q. IS AN ELCC OF 37% APPROPRIATE FOR THE GENERATION MARGINAL COST STUDY?

A. Yes. Recall that a marginal cost study evaluates the cost of an optimal system if it were built from scratch using today's technology.[13/] The capacity value used for wind in the marginal cost study should reflect the overall capacity contribution of renewable resources, at the penetration assumed in the marginal cost study (i.e. 20 percent for 2022). The values included in the 2022 IRP reflect incremental additions to the existing resource mix. It is reasonable to expect that an optimal mix of renewables, at 20 percent of system energy, would be sufficiently diverse to maintain an ELCC at or near the current incremental ELCC.

Q. WHAT DO YOU RECOMMEND RELATED TO WIND CAPACITY?

A. I maintain the recommendation in my Opening Testimony with no change.

12/ AWEC/401 (PGE Response to AWEC DR 335).

13/ See Lazar, J., Smart Rate Design for a Smart Future, Montpelier, VT: Regulatory Assistance Project, at Appendix A:A-2 (July 2015) available at: https://www.raponline.org/wp-content/uploads/2016/05/appendix-a-smart-rate-design-2015-aug-31.pdf.

b. Include a Weighting of Emitting and Non-Emitting Capacity Resources

Q. WHAT ISSUE DID YOU RAISE IN YOUR OPENING TESTIMONY REGARDING NON-EMITTING CAPACITY RESOURCES?

A. PGE's marginal cost model reflects a mix of thermal and renewable resources when modeling energy costs but not when modeling capacity costs. This is a mismatch that is not consistent with the current regulatory environment. A long run marginal cost model should model the cost of an optimal system, regardless of historic investments.[14/] HB 2021 requires utilities to serve 100% of their load with renewable and carbon-free generation by 2045.[15/] Given this requirement, it is unreasonable to assume that an optimal system has only emitting capacity resources. In fact, PGE currently plans to add non-thermal capacity resources to its system.[16/] I recommended that capacity resources be modeled in a similar manner as energy resources, with a weighted average of emitting and non-emitting capacity costs.

Q. HOW DID PGE RESPOND TO YOUR RECOMMENDATION?

A. PGE notes that before accounting for secondary costs and benefits of renewables, HB 2021 will likely increase costs allocated to residential and small commercial classes.[17/] PGE appears to agree that it is appropriate to consider capacity costs of non-emitting resources but prefers to wait until after its next IRP to make this change.[18/]

14/ Id.
15/ RCW 19.405.050(1).
16/ Docket No. UM 2166, PGE 2021 All-Source Request for Proposals (April 28, 2021).
17/ PGE / 2200 Macfarlane – Tang / 4:23-5:1-3.
18/ See id. at 5:5-9.

Q. IS THERE A NEED TO WAIT FOR MORE DETAILED STUDIES PRIOR TO UPDATING PGE'S MARGINAL COST MODEL FOR HB 2021?

A. No. There is no requirement that incidental benefits of resources be modeled in a marginal cost study. PGE notes that the "generation marginal cost study is a simplified model and does not include all of the benefits associated with the renewable resource."[19/] It is common when modeling to make simplifying assumptions. The Commission and other parties have accepted the general structure of PGE's simplified model in past cases without accounting for all benefits of either thermal or renewable resources despite the fact that the model included both thermal and renewable resources in the past.[20/] Absent a more complex model, PGE's current simplified model is appropriate to address changes raised by HB 2021.

Q. DID AWEC ATTEMPT TO DEVELOP A MORE COMPLEX MODEL TO ACCOUNT FOR ADDITIONAL BENEFITS OF THERMAL AND RENEWABLE RESOURCES?

A. Yes. PGE has performed detailed estimates of miscellaneous resource benefits in its 2019 IRP. However, PGE declined to provide workpapers supporting these benefits.[21/] Without the more granular underlying data, I did not have sufficient information to integrate other benefits of thermal and renewable resources from the IRP into PGE's cost model.

Q. GIVEN THE POTENTIAL IMPACT OF OTHER BENEFITS, WHY DO YOU RECOMMEND IMPLEMENTING A CHANGE NOW RATHER THAN WAITING?

A. My recommendation provides a transition step towards fully modeling a renewable system. Under my recommendation, capacity costs remain predominantly thermal. This is an incremental step when compared to other jurisdictions such as Washington, which model costs

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19/ AWEC/401 (PGE Response to AWEC DR 333).

20/ For example, simple cycle combustion turbines ("SCCTs") and CCCTs differ with respect to ramp time, frequency control, and a host of other ancillary benefits.

21/ AWEC/401 (PGE Response to AWEC DR 144 and 145).

using 100 percent non-emitting capacity and generation resources.[22/] The 2019 IRP shows that non-energy and capacity benefits of renewable capacity resources are small relative to the incremental cost. Figure 6-10 of PGE's 2019 IRP shows the cost of a 4-hour battery resource is 233 percent of the cost of an SCCT, even after accounting for other benefits.[23/] Consequently, excluding these benefits at this time from PGE's simplified marginal cost model will not have a material impact on the results.

Q. DOES STAFF AGREE THAT HB 2021 WILL SIGNIFICANTLY IMPACT COST ALLOCATIONS?

A. Yes. Staff notes that "this change might be significant because in general increasing the cost of capacity would spread rates from industrial customers onto smaller customers."[24/] Staff's expectations are consistent with PGE's expectations and the results of AWEC's non-emitting capacity cost proposal. Consequently, it is likely not a matter of "if" but "when" PGE's marginal cost study will need to be updated to accommodate a fully renewable system. Beginning to phase this change in now is in the interest of all customers and better reflects the marginal cost of PGE's system.

Q. WHAT IS YOUR RECOMMENDATION WITH RESPECT TO NON-EMITTING CAPACITY COST?

A. I maintain my Opening Testimony recommendation to smooth the transition to a fully renewable generation marginal cost model by weighting capacity costs of emitting and non-emitting resources.

22/ See WAC 480-85-060(3), at Table 2.

23/ The "Capacity" bar of this figure shows the ELCC adjusted cost of an SCCT. The "Net Cost" of $106 per kW year, plus the "Capacity benefit" of $75 per kW-year, or $181 per kW-year, is the total cost less non-capacity benefits. This is 233 percent of the cost of an equivalently sized SCCT.

24/ Staff/1400 St. Brown/12:5-7.

c. Reduce the Reserve Margin from 12 to 10 Percent

Q. WHAT ISSUE DOES STAFF RAISE REGARDING THE RESERVE MARGIN?

A. When modeling generation costs, the cost of capacity is scaled up by the reserve margin. Staff proposes reducing the reserve margin from 12 percent to 10 percent. Staff makes this recommendation based on speculation that resource adequacy efforts will reduce reserve requirements for PGE. Staff also considers operating reserves to be a more appropriate measure for long-run marginal cost than planning reserves.

Q. WHAT IS THE DIFFERENCE BETWEEN OPERATING RESERVES AND PLANNING RESERVES?

A. Operating reserves reflect the resources that are available to a utility to meet load within a particular time frame. These reserves are important for PGE to be able to respond to changes in load, or unexpected plant or transmission outages. Operating reserves do not include resources that may be available in the long term but not the short term. For example, operating reserves do not include plants that are undergoing maintenance.

Planning reserves reflect the difference between planned load and resource capacity. PGE-established planning reserves are designed to achieve an acceptable loss of load probability. PGE's 2019 IRP average reserve margin is 16 percent.[25/] PGE's planning reserves reflect an optimal level of long-term reserves.

Reserve margin is reserves divided by load. Operating reserve margin is calculated based on current load rather than peak load and are thus not relevant when evaluating capacity costs, which serve peak load. Planning margins however are based on peak load and are therefore appropriate for use in the cost of capacity calculations.

[25/] PGE 2019 IRP, at 288, Table G-1 (July 2019).

Q. SHOULD A LONG-RUN MARGINAL COST STUDY USE OPERATING OR PLANNING RESERVE MARGINS?

A. The long-run marginal cost study should use planning reserve margins. This is appropriate for two reasons.

1. The marginal cost study reflects the cost of an optimal resource mix.[26/] The optimal resource mix should have sufficient capacity to meet long-term loss of load probability targets.
2. The long-run marginal cost study evaluates the capital costs of meeting demand and energy requirements. The operating reserve does not account for all capital costs because it does not reflect capital investments that may be unavailable due to maintenance, low loads, or other economic reasons.

Q. WHAT IS STAFF'S BASIS FOR CONCLUDING THAT RESOURCE ADEQUACY EFFORTS WILL REDUCE PGE'S RESERVE REQUIREMENTS?

A. Staff alleges that a regional resource adequacy program, like the one the Northwest Power Pool is leading, "may enable a lower reserve margin because large systems are less vulnerable to individual, large contingencies."[27/] As the quotation indicates, however, this position is speculative at this time. Furthermore, as PGE has indicated, the Northwest Power Pool's resource adequacy program "is in a non-binding phase and indicative information on future planning reserve margins is not yet available. The binding phases of the NWPP WRAP are not planned to commence until 2023 and beyond."[28/] Therefore, even if a regional resource

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[26/] See Lazar, J., Smart Rate Design for a Smart Future, Montpelier, VT: Regulatory Assistance Project, at Appendix A:A-2 (July 2015) available at: https://www.raponline.org/wp-content/uploads/2016/05/appendix-a-smart-rate-design-2015-aug-31.pdf.

[27/] AWEC/401 (Staff Resp. to AWEC DR 004(e) (quoting Northwest Power Pool, "Agenda for Dynamics of Today's Energy System A Resource Adequacy Symposium," October 2, 2019, available at: https://www.nwpp.org/private-media/documents/2019.10.02_Resource_Adequacy_Symposium_ALL_SLIDES.pdf).

[28/] AWEC/401 (PGE Resp. to AWEC DR 343).

adequacy program does lead to a reduction in reserve requirements, this impact is still several years away and can be revisited in PGE's next general rate case.

Q. WHAT IS AWEC'S RESPONSE TO STAFF'S PROPOSAL?

A. It is not realistic to assume that resource adequacy efforts will reduce planning reserve requirements by 44 percent. AWEC recommends adopting PGE's 2019 IRP planning reserve margin of 16 percent.

d. <u>Net Out Energy Sales to Reduce the Cost of Capacity</u>

Q. WHAT ISSUE DOES STAFF RAISE REGARDING NET ENERGY SALES?

A. Staff proposes offsetting the capacity cost of an SCCT by the value of "net energy sales" and other revenue.[29/]

Q. HOW DOES PGE RESPOND TO STAFF'S PROPOSAL?

A. PGE responds that netting out energy sales is an "unnecessary complexity".[30/]

Q. WHAT IS YOUR RESPONSE TO STAFF'S RECOMMENDATION?

A. I see three issues with Staff's recommendation.

1. "Net Energy Sales" relied on by Staff reflects market sales from the SCCT during hours when it is actually providing capacity service. The data relied on by Staff to calculate "net sales" show that the SCCT is expected to operate, on average, 76 hours per year. The credit for net sales appears to be associated with energy produced during these hours. Given the nature of Aurora, these hours occur during the highest market prices of the year and actually represent hours during which the SCCT's generation should be considered to serve capacity needs rather than energy needs.

29/ Staff/1400 St. Brown/14:7-9.
30/ PGE/2200 Macfarlane – Tang / 6:1-2.

2. The data relied on by Staff appear to reflect the market value of all SCCT-dispatched hours regardless of whether PGE is actually selling into the wholesale market during these hours. This means that the term “net sales” is a misnomer and there is actually no offsetting revenue being received from the “net sales”.
3. Staff fails to account for “other revenue” generated by CCCTs. Staff agrees that if CCCTs make economic energy sales, it is appropriate to offset capital costs for a CCCT in a similar manner as Staff proposed for an SCCT.[31/]

Q. WHAT IS YOUR RECOMMENDATION REGARDING NET SALES?

A. Because net sales appear to occur only during times when SCCTs should be considered to be providing capacity services, it is not appropriate to offset the capacity cost of an SCCT with net sales. I recommend the Commission not adopt Staff’s net sales proposal.

e. <u>Allocate 10 Percent of Smart Grid Costs to Generation</u>

Q. WHAT ISSUE DOES STAFF RAISE REGARDING SMART GRID COSTS?

A. Staff notes that PGE’s smart grid capabilities support PGE’s demand response (“DR”) programs. Staff recommends functionalizing 10 percent of the revenue requirement associated with Project Touchpoints to production. Staff justifies this proposal by suggesting that industrial customers pay almost none of the cost of DR programs.[32/]

Q. HOW ARE DR PROGRAM COSTS PASSED ON TO CUSTOMERS?

A. DR program costs are recovered from customers through Schedule 135, the Demand Response Cost Recovery Mechanism. Industrial customers pay their fair share of DR program costs through this schedule. Staff incorrectly characterizes Project Touchpoints as a cost of a DR

31/ AWEC/401 (Staff Response to AWEC DR 5).
32/ Staff/1400, St. Brown/15:5-8.

program. Project Touchpoints, however, did not enable PGE's DR programs and had no cost components specifically added to serve DR programs. It is therefore inappropriate to consider any of Project Touchpoints costs as DR program costs. At most, Project Touchpoints indirectly reduces the cost of implementing and expanding DR programs.

Q. WHAT IS THE BASIS FOR STAFF'S ASSUMPTION THAT 10 PERCENT OF PROJECT TOUCHPOINTS COSTS ARE DR COSTS?

A. Staff does not appear to have a basis for this number, other than that it was the percentage agreed to in a stipulation from PGE's last rate case. As the Commission is well aware, however, stipulations are nonprecedential and are the product of give-and-take from all parties. The stipulation from UE 335 cannot serve as an evidentiary basis for the reasonableness of Staff's proposal in this case.

Q. DOES STAFF CORRECTLY APPROXIMATE THE REVENUE REQUIREMENT ASSOCIATED WITH 10 PERCENT OF PROJECT TOUCHPOINTS?

A. No. Staff assumes that 10 percent of Project Touchpoints is approximately $10 million in revenue requirement. In fact, 10 percent of the 2022 revenue requirement for this project is $2.4 million.[33] If the Commission adopts Staff's recommendation, the Commission should require Staff to update its calculations using $2.4 million rather than $10 million.

Q. ARE DR PROGRAMS SUFFICIENTLY DEVELOPED TO BE CONSIDERED VIABLE ENERGY AND CAPACITY RESOURCES?

A. No. PGE's DR programs are highly uneconomic before burdening them with indirect costs of Project Touchstone. PGE spent [redacted] across its four DR programs in 2020 and achieved an average winter curtailment of [redacted].[34] This equates to [redacted] per kW-year. Burdening

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[33] AWEC/401 (PGE Response to AWEC DR 330 Attachment A).
[34] See AWEC/401 (PGE Response to AWEC DR 329 Confidential Attachment A).

these programs with an additional $2.4 million per year from Project Touchpoints increases the cost to [redacted] per kW-year. For comparison, the cost of 4-hour battery storage is $222 per kW-year, and only $181 per kW-year after accounting for energy and flexibility value. A much more economical approach to DR, and one that does not require support of smart grid technologies, is to directly contract with large customers. For example, I personally assisted on a transaction for demand response between a Northwest utility and a large customer. While the details of that transaction are confidential, it provided this utility with more DR than PGE's entire portfolio and at a fraction of the cost.

Q. WHAT IS YOUR RECOMMENDATION REGARDING SMART GRID COSTS?

A. I recommend that the Commission accept PGE's allocation of Project Touchpoints and reject Staff's proposal. AWEC does not oppose PGE commissioning a third-party study on how to allocate smart grid costs in future cases. If, however, the Commission adopts Staff's recommendation, the Commission should require Staff to update its calculations using $2.4 million rather than $10 million.

f. <u>Update Natural Gas Prices</u>

Q. WHAT ISSUE DOES STAFF RAISE REGARDING NATURAL GAS PRICES?

A. Staff notes that natural gas prices underlying PGE's marginal cost model increased after PGE's case was filed. Staff recommends updating natural gas prices in the marginal cost model.[35/] PGE finds Staff's gas price update recommendation has merit.[36/]

[35/] Staff/1400 St. Brown/17:5-10.
[36/] PGE / 2200 Macfarlane – Tang / 6:3-5.

Q. WHAT IS AWEC'S RESPONSE TO STAFF'S RECOMMENDATION?

A. While using current data has merit in some circumstances, what inputs are updated and when, and how updates are applied should be consistent and follow a set standard. Staff's recommendation does not prescribe when prices should be updated or what types of changes warrant triggering a price update. Since Staff filed its Opening Testimony, gas prices have decreased and may change again in the next few months. Staff's recommendation is also not applied systematically across the marginal cost study. For example, Staff's recommendation to offset SCCT costs using net sales relies on Aurora output that uses gas as an input. Higher gas prices mean fewer net sales for peaker units. Updating the marginal cost model's gas price without also updating the net sales model, wholesale electricity prices, and other gas-dependent inputs is not consistent.

Q. WHAT IS YOUR RECOMMENDATION REGARDING GAS PRICE UPDATES IN THE MARGINAL COST STUDY?

A. While it is reasonable to update inputs, such updates should be established prospectively to prevent biased and non-systematic updates. I recommend that no update be made at this time, and that parties collaborate outside this rate case to establish an appropriate framework for updating marginal cost inputs during a rate case filing.

Q. PLEASE SUMMARIZE YOUR RECOMMENDATIONS IN REPLY TO TESTIMONY ON GENERATION MARGINAL COST.

A. I maintain my original recommendation for generation marginal cost with one modification. I recommend modifying the 12 percent reserve margin used in PGE's opening testimony to 16 percent to be consistent with PGE's current planning reserve margin in the 2019 IRP. The impact of this change is summarized in Exhibit AWEC 402 at page 3.

IV. CUSTOMER IMPACT OFFSET

Q. WHAT WAS AWEC'S RECOMMENDATION REGARDING THE CUSTOMER IMPACT OFFSET ("CIO")?

A. AWEC recommended that no CIO be applied in this case because AWEC's Opening Testimony recommended an overall rate decrease.

Q. WHAT WAS STAFF'S RECOMMENDATION REGARDING THE CIO?

A. Staff recommended that the CIO be used to prevent Schedule 90 from receiving a rate decrease.

Q. WHY DID STAFF RECOMMEND THAT THE CIO BE USED TO PREVENT A RATE DECREASE FOR SCHEDULE 90?

A. Staff provides two reasons for preventing a rate decrease for schedule 90. First, Staff notes that the Commission has previously supported no rate decreases for schedules, presumably even when warranted by the marginal cost study.[37/] Second, Staff prefers that Schedules 89 and 90 receive consistent CIO treatment.[38/]

Q. WHAT IS THE CIO TYPICALLY USED FOR?

A. The CIO is essentially a subsidy of some customers by other customers. As with all subsidies, the use of the CIO can make rates less efficient by sending the wrong price signal to customers. Because of the undesirable attributes of a CIO, it is typically only used to mitigate cost-justified price changes that greatly exceed the system average. In Order No. 14-422, the Commission found that "[t]he CIO is a mechanism that represents departures from strict cost-of-service allocations; it is designed to achieve greater rates simplicity, comprehension, and acceptability and to mitigate the effects of cost-justified increases that greatly exceed the

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37/ Staff/1400 St. Brown/18:6-8.
38/ Id. at 18:12-14.

system overall average increase."[39/] The Commission has considered a cost increase that is the greater of 12 percent or three times the system average to qualify as greatly exceeding the system average.[40/]

Q. WHAT IS AWEC'S RESPONSE TO STAFF'S PROPOSAL TO LIMIT SCHEDULE 90 TO NO RATE DECREASE?

A. There is no economic basis for limiting any schedule's rate change to an arbitrary number such as zero percent. The only plausible reason for preventing rate decreases when they are warranted are concerns about optics and public perception. The Commission appropriately approves rate decreases in the presence of overall rate increases when circumstances warrant it. In this case, the following factors warrant a decrease for schedules 89 and 90:

1. Schedule 90 customers are price sensitive and have multiple production cites with the ability to shift energy use across utilities. Staff's proposal will make loss of load and loss of load growth for PGE more likely, to the detriment of all customer classes.
2. PGE's use of supplemental schedules allows the majority of PGE's rate changes to occur outside of rate cases. This masks the true percentage change in customer rates across rate cases and limits the ability to set cost-based rates within rate cases. CUB raised this concern in its Opening Testimony.[41/]

Q. WHY IS PRICE SENSITIVITY RELEVANT TO STAFF'S RECOMMENDATION?

A. The Commission has indicated that threat of bypass is a circumstance that warrants cost-justified rate decreases in the presence of an overall rate increase.[42/] Shifting production, and

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39/ Docket No. UE 283, Order No. 14-422, at 12 (Dec. 4, 2014).
40/ Id. at 12, 13.
41/ See CUB/100, Jenks/8:3-13:11.
42/ Docket Nos. UG 288 and UM 1753, Order No. 16-109, at 21-22 (Mar. 15, 2016). The Commission has stated that "compelling evidence that warrants more immediate action" justifies "reducing rates for some customers where

thus energy demand, from PGE to facilities served by other utilities is one method of bypassing PGE.

Q. WHY SHOULD PRICE SENSITIVITY OF SCHEDULE 90 BE TREATED DIFFERENTLY FROM PRICE SENSITIVITY OF OTHER SCHEDULES, SUCH AS SCHEDULE 32?

A. Under Staff's proposal, Schedule 90 would be *paying* a subsidy, and any subsidy-caused load decrease should be considered an inefficient outcome. On the other hand, Schedule 32 customers would *receive* subsidies, and thus any price related load decreases for Schedule 32 should be considered an efficient outcome.

Q. HOW HAVE PGE'S RATES CHANGED SINCE UE 335 RATES WERE APPROVED?

A. Relative to UE 335 rates, 2022 overall rates are 10.7 percent higher, an annual average increase of 3.6 percent.[43/] Incorporating the Third Partial Stipulation, the stand-alone rate impact of UE 394 is only 2.4 percent.[44/] This means that more than three quarters of PGE's overall rate increase since its last rate case has occurred outside of a general rate case through supplemental schedules.

Q. WHY IS THIS RELEVANT TO STAFF'S RECOMMENDATION TO PREVENT SCHEDULES 89 AND 90 FROM RECEIVING A RATE DECREASE?

A. Parties have no ability to address allocation of rates outside general rate cases. As more revenue and revenue increases are shifted outside general rate cases, general rate cases have fewer dollars available to address cost-justified rate changes. To illustrate this, consider a thought experiment where 100 percent of revenue requirement increases are recovered between

rates are increased for other customers." According to the Commission, "[c]ompelling evidence would be evidence of impending bypass or plant closure.").

43/ AWEC/401 (PGE Resp. to AWEC DR 308, Attachment A).

44/ AWEC/401 (PGE Resp. to AWEC DR 308, Attachment A).

rate cases through supplemental schedules. In this scenario there is no overall rate increase during a rate case. Under Staff's recommendation, there would be no mechanism to align costs with rates because every cost-justified rate change would require at least one schedule to experience a decrease.

Therefore, if the Commission agrees with Staff's position that customer classes generally should not receive decreases while other classes receive increases, the proper way to implement this principle is to modify Staff's proposal to include between-rate-case rate changes when evaluating the percentage change that a schedule has received.

Q. HOW HAVE BETWEEN-RATE-CASE CHANGES AFFECTED EACH SCHEDULE?

A. Not counting rates proposed in this case, overall rates have increased 8 percent since 2019. Exhibit 403 summarizes these changes by schedule. Schedules 89 and 90 have had the largest increases, at 9.3 and 9.7 percent respectively. Residential rate increases were below average, at 6.6 percent.

Q. WHAT IS THE OVERALL RATE IMPACT FOR EACH SCHEDULE WHEN BETWEEN-RATE-CASE CHANGES ARE ACCOUNTED FOR?

A. Including the stipulated revenue requirement in this case, the 2019 to 2022 overall rate change is 10.7 percent. Under PGE's proposed rate spread in this case, all schedules except Schedule 92 Traffic Signals experience a moderate rate increase from 2019, ranging from 5.7 percent for Schedule 83, to 15.5 percent for Schedule 32.[45/] Schedule 90 would experience an overall increase of 7.2 percent. No schedule experiences a change that is more than two times the average change.

[45/] AWEC/401 (PGE Resp. to AWEC DR 308, Attachment A).

Q. HOW WOULD CUSTOMERS ON SCHEDULES 89 AND 90 HAVE FAIRED IF THEY HAD THE MEANS AND OPPORTUNITY TO ADDRESS RATE SPREAD IN EVERY BETWEEN-RATE-CASE FILING?

A. Because marginal cost results change gradually, each filing would have afforded Schedules 89 and 90 a chance to have a cost-based rate reduction relative to the rate that went into effect. This means that these schedules would have had lower bills in 2020 and 2021. It also means that these schedules would have had a lower starting rate entering the 2022 rate case, reducing, and possibly eliminating, the need for a cost-based rate decrease.

Q. WHY DON'T PARTIES ADDRESS RATE SPREAD IN NON-GRC PROCEEDINGS?

A. There is not currently a process in place for parties to address rate spread between rate cases. This is appropriate because of the cost and effort involved in evaluating rate spread. Typically, between-rate-case changes are spread on a predetermined factor such as equal percent of generation revenue. Rather than require parties to participate in a rate spread discussion for every supplemental filing, the Commission should test overall rate changes based on the total rate-case to rate-case rate change.

Q. IF THE COMMISSION ALLOWS A RATE DECREASE IN THIS CASE FOR SCHEDULES 89 AND 90, CONSISTENT WITH PGE'S COST STUDY, WILL THESE SCHEDULES REALIZE AN OVERALL RATE DECREASE SINCE PGE'S LAST RATE CASE?

A. No. Schedule 89 will still experience an overall increase of 7% and Schedule 90 will experience an overall increase of 6.5%.

Q. WHAT IS YOUR RECOMMENDATION REGARDING THE CIO?

A. I recommend that the CIO be used only to reduce rates for customer classes with rate increases more than the greater of 12 percent or three times the overall rate increase. This is the standard implemented by the Commission in Order No. 14-422.[46] The rate increase should be judged relative to the approved rates in Docket No. UE 335. I also recommend that no schedule be limited to a zero percent rate decrease.

Q. WHAT IS THE AVERAGE RATE IMPACT UNDER YOUR RECOMMENDED COST STUDY AND CIO?

A. Exhibit AWEC 402 summarizes the impacts of my recommendations. The overall rate impacts, including between rate case changes, is found on page 1. The standalone impacts of this rate case are found on page 2. Under my proposal no customer experiences a rate change more than three times the average change and no customer experiences a rate decrease relative to rates approved in Docket No. UE 335.

V. SUBTRANSMISSION

Q. WHAT ISSUE DID YOU RAISE REGARDING SUBTRANSMISSION RATES?

A. In my Opening Testimony, I proposed that a subtransmission rate be provided for Schedule 90. PGE opposed my recommendation on the basis that PGE has not added new subtransmission customers in 16 years.

Q. WHAT IS YOUR RESPONSE TO PGE'S CONCERN?

A. PGE does not provide a rational basis for not offering a subtransmission option. Past customer additions have no bearing on future economic development in PGE's service territory. AWEC has members that have expressed interest in a subtransmission rate for Schedule 90, particularly at the reduced eligibility threshold PGE proposes in this case (which AWEC

[46] Docket No. UE 283, Order No. 14-422, at 12 (Dec. 4, 2014).

supports). Subtransmission rates are common options for large customers across the U.S.[47/] Offering a subtransmission rate does not impose any material costs on PGE, has no impact on any other customer class, and provides customers with the option of taking service at a higher voltage. Subtransmission service allows customers more flexibility in how they design and utilize their electric service. I maintain my recommendation to develop a subtransmission rate for Schedule 90 in this proceeding.

VI. DIRECT ACCESS COST ALLOCATION

Q. WHAT CONCERNS DID YOU RAISE REGARDING PGE'S PROPOSAL TO ASSIGN CERTAIN COSTS TO DIRECT ACCESS CUSTOMERS?

A. In Direct Testimony, PGE proposed to allocate costs of the Company's existing Solar Payment Option ("SPO") under Schedule 137 to direct access, as well as costs associated with new Schedule 150, transportation electrification.[48/]

In my Opening Testimony, I opposed this allocation on the basis that PGE had not justified this treatment. Specifically, for the SPO, PGE does not propose to allocate only the "above-market" costs associated with this offering, as the Commission approved for the Community Solar Program. PGE also did not propose to allocate those costs based on total revenues, consistent with the Community Solar Program allocation, and instead proposed to allocate them based on generation. Meanwhile, for Schedule 150, PGE failed to explain what benefits direct access customers receive from this program or limit its allocation to "above-market" public policy costs similar to those associated with the Community Solar Program.

47/ See Central Maine Power Company, Rate LGS-ST-TOU, Large General Service – Subtransmission- Time-of-Use; New York State Electric & Gas Corporation, 3S - Non-Residential Subtransmission Service with Demand; and Southern California Edison, Schedule TOU-8 Sheet, Time-of-Use-General Service-Large.

48/ PGE/1200, Macfarlane-Tang/44:13-45:9.

Q. HOW DID PGE RESPOND TO YOUR TESTIMONY ON THESE ISSUES?

A. PGE did not substantively respond. In PGE's Reply Testimony, limited to a single page, the Company suggests that "the Commission accept PGE's proposed nonbypassability in this case and revisit this issue after UM 2024 concludes."[49/] PGE further states that it "seeks to ensure that large nonresidential customers that choose to purchase energy from an [Electricity Supply Service ("ESS")] pay their fair share of system costs," but entirely fails to explain or justify how its proposals result in this outcome.[50/]

Q. CAN THE COMMISSION ACCEPT PGE'S PROPOSAL?

A. No. As the applicant in this case PGE carries the burden of proof and persuasion to demonstrate that its proposal is just and reasonable.[51/] I raised substantive criticisms with PGE's nonbypassability charges in my Opening Testimony, which PGE has not even attempted to rebut. The Company has clearly failed to meet its burden, so its proposals cannot be adopted. AWEC agrees that UM 2024 is an appropriate docket to address nonbypassability of costs to direct access. However, the Commission must base any decision regarding nonbypassability in this rate case on evidence in the record. The only justifiable decision, therefore, is to reject PGE's proposals and revisit this issue in UM 2024.

Q. DO YOU HAVE ANY OTHER CONCERNS WITH PGE'S NONBYPASSABILITY PROPOSALS?

A. Yes. PGE's proposals appear to have changed on this issue between its Direct and Reply Testimony. In Direct Testimony, PGE proposed nonbypassable charges for Schedules 137 and 150 (as well as for its Flexible Load Plan, but those costs are not included in this case). In

49/ PGE/2200, Macfarlane-Tang/14:8-9.
50/ Id. at 14:11-12.
51/ See ORS § 757.210(1)(a).

Reply Testimony, PGE states that it is proposing nonbypassable charges for Schedules 137, 135, and 150. Schedule 135 is PGE's Demand Response Cost Recovery Mechanism. While PGE's opening testimony referenced this concept in passing in its policy testimony, it offered no justification for it or details on the charge itself.[52/] Further, Schedule 135, as filed with PGE's application, continues to exclude long-term direct access customers.[53/] Accordingly, the Commission certainly cannot adopt a nonbypassable charge for demand response in this case, as PGE has provided no explanation or justification of this charge, failed to include any such charge in its tariffs accompanying its initial filing, and improperly raised this issue on rebuttal.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

52/ PGE/100, Pope-Sims/15:4-7.
53/ PGE/1201, Macfarlane-Tang at 69.

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UE 394

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

EXHIBIT AWEC/401

RESPONSES TO DATA REQUESTS

(REDACTED)

October 7, 2021

To: Jesse O. Gorsuch
Alliance of Western Energy Consumers

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 394
PGE Response to AWEC Data Request 144
Dated September 23, 2021

Request:

Please refer to PGE's 2019 Integrated Resource Plan, page 107, figure 4-14: "Reference Case loss-of-load expectation in 2025."

a. Please provide the loss of load probability by hour and month for the high need future, reference case, and low need future provided for each future year studied.

b. Please also refer to page 105, figure 4-11: "Loss-of-load hour profiles for 2025 with and without demand response." Please provide loss of load probability by hour and month with demand response for the high need future, reference case, and low need future provided for each future year studied.

Response:

PGE objects that this request seeks information that is neither relevant nor reasonably calculated to lead to the discovery of admissible evidence in this case. This request seeks information related to years 2023 – 2025 from Docket No. LC 73. The test year for this general rate case is 2022.

October 7, 2021

To: Jesse O. Gorsuch
Alliance of Western Energy Consumers

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 394
PGE Response to AWEC Data Request 145
Dated September 23, 2021

Request:

Please refer to PGE's 2019 Integrated Resource Plan. Please provide the workpapers used to calculate the values for each resource in each of the following figures and tables:

a. Page 162, Table 6-4: "Energy values for new resource options",

b. Page 163, Table 6-5: "Flexibility values of new dispatchable resource options",

c. Page 167, Table 6-6: "ELCC and capacity values of resource options",

d. Page 169, Figure 6-9: "Net costs of energy resource options by COD" for 2023 only, and

e. Page 170, Figure 6-11: "Net costs of capacity resource options by COD" for 2023 only.

Response:

PGE objects that this request seeks information that is neither relevant nor reasonably calculated to lead to the discovery of admissible evidence in this case. This request seeks information related to years 2023 – 2025 from Docket No. LC 73. The test year for this general rate case is 2022.

December 27, 2021

To: Jesse O. Gorsuch
Alliance of Western Energy Consumers

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 394
PGE Response to AWEC Data Request 308
Dated December 20, 2021

Request:

Please provide rate increases by rate schedule since PGE's last rate case, Docket No. UE 335.

Response:

Attachment 308-A provides the requested information. See the worksheet labeled, "Table 3 2000-2019."

TABLE 3
PORTLAND GENERAL ELECTRIC
ESTIMATED EFFECT ON CONSUMERS' TOTAL ELECTRIC BILLS
2022

CATEGORY	RATE SCHEDULE	CUSTOMERS (Forecast SSEP21E22)	MWH SALES	TOTAL ELECTRIC BILLS: CURRENT (all supplementals except LIA, PPC & Sch 109)	TOTAL ELECTRIC BILLS: PROPOSED (all supplementals except LIA, PPC & Sch 109)	Change: AMOUNT	Change: PCT.
Residential	7	808,245	7,569,338	$928,099,756	$1,037,507,051	$109,407,295	11.8%
Employee Discount				($1,110,239)	($1,145,856)	($35,617)	
Subtotal				$926,989,517	$1,036,361,195	$109,371,678	11.8%
Outdoor Area Lighting	15	0	13,922	$3,038,151	$3,284,165	$246,014	8.1%
General Service <30 kW	32	94,547	1,588,439	$183,912,419	$212,406,502	$28,494,083	15.5%
Opt. Time-of-Day G.S. >30 kW	38	376	27,371	$3,656,008	$3,997,652	$341,643	9.3%
Irrig. & Drain. Pump. < 30 kW	47	2,644	19,423	$3,780,692	$4,147,603	$366,911	9.7%
Irrig. & Drain. Pump. > 30 kW	49	1,449	62,083	$8,634,342	$9,742,289	$1,107,947	12.8%
General Service 31-200 kW	83	11,463	2,870,308	$266,001,667	$297,532,853	$31,531,186	11.9%
General Service 201-4,000 kW							
Secondary	85-S	1,190	2,074,462	$166,795,555	$176,368,221	$9,572,666	5.7%
Primary	85-P	171	570,537	$42,335,768	$45,048,803	$2,713,035	6.4%
Schedule 89 > 4 MW							
Secondary	89-S	3	95,807	$6,197,894	$6,646,791	$448,896	7.2%
Primary	89-P	15	639,544	$40,493,995	$43,311,103	$2,817,108	7.0%
Subtransmission	89-T/75-T	5	51,499	$4,015,478	$4,304,933	$289,454	7.2%
Schedule 90	90-P	6	2,827,139	$164,305,158	$176,181,379	$11,876,221	7.2%
Street & Highway Lighting	91/95	185	43,876	$9,684,133	$10,537,007	$852,873	8.8%
Traffic Signals	92	0	2,576	$214,993	$193,123	($21,870)	-10.2%
COS TOTALS		920,299	18,456,323	$1,830,055,770	$2,030,063,617	$200,007,847	10.9%
Direct Access Service 201-4,000 kW							
Secondary	485-S	224	493,315	$12,510,200	$9,774,117	($2,736,083)	
Primary	485-P	55	341,815	$6,513,336	$5,850,198	($663,138)	
Direct Access Service > 4 MW							
Secondary	489-S	0	0	$0			
Primary	489-P	16	1,057,666	$10,783,289	$11,196,257	$412,967	
Subtransmission	489-T	3	266,569	$0	$1,282,633	$1,282,633	
New Load Direct Access Service > 10MW							
Primary	689-P	1	37,473	$266,934	$468,982	$202,048	
DIRECT ACCESS TOTALS		299	2,196,838	30,073,760	28,572,187	($1,501,573)	
COS AND DA CYCLE TOTALS		920,598	20,653,161	$1,860,129,531	$2,058,635,804	$198,506,273	10.7%

TABLE 3
PORTLAND GENERAL ELECTRIC
ESTIMATED EFFECT ON CONSUMERS' TOTAL ELECTRIC BILLS
2022

CATEGORY	RATE SCHEDULE	Forecast SSEP21E22 CUSTOMERS	MWH SALES	TOTAL ELECTRIC BILLS CURRENT all supplementals except LIA, PPC & Sch 109	TOTAL ELECTRIC BILLS PROPOSED all supplementals except LIA, PPC & Sch 109	Change AMOUNT	Change PCT.
Residential	7	808,245	7,569,338	$989,799,621	$1,037,507,051	$47,707,431	4.8%
Employee Discount				($1,110,239)	($1,145,856)	($35,617)	
Subtotal				$988,689,382	$1,036,361,195	$47,671,814	4.8%
Outdoor Area Lighting	15	0	13,922	$3,117,688	$3,284,165	$166,477	5.3%
General Service <30 kW	32	94,547	1,588,439	$198,672,623	$212,406,502	$13,733,879	6.9%
Opt. Time-of-Day G.S. >30 kW	38	376	27,371	$3,823,161	$3,997,652	$174,491	4.6%
Irrig. & Drain. Pump. < 30 kW	47	2,644	19,423	$3,952,188	$4,147,603	$195,415	4.9%
Irrig. & Drain. Pump. > 30 kW	49	1,449	62,083	$9,174,867	$9,742,289	$567,422	6.2%
General Service 31-200 kW	83	11,463	2,870,308	$287,568,509	$297,532,853	$9,964,343	3.5%
General Service 201-4,000 kW							
Secondary	85-S	1,190	2,074,462	$180,149,934	$176,368,221	($3,781,712)	-2.1%
Primary	85-P	171	570,537	$45,903,546	$45,048,803	($854,743)	-1.9%
Schedule 89 > 4 MW							
Secondary	89-S	3	95,807	$6,817,660	$6,646,791	($170,869)	-2.5%
Primary	89-P	15	639,544	$44,267,613	$43,311,103	($956,510)	-2.2%
Subtransmission	89-T/75-T	5	51,499	$4,322,637	$4,304,933	($17,704)	-0.4%
Schedule 90	90-P	6	2,827,139	$180,212,670	$176,181,379	($4,031,291)	-2.2%
Street & Highway Lighting	91/95	185	43,876	$9,927,744	$10,537,007	$609,263	6.1%
Traffic Signals	92	0	2,576	$229,824	$193,123	($36,701)	-16.0%
COS TOTALS		920,299	18,456,323	$1,966,830,044	$2,030,063,617	$63,233,572	3.2%
Direct Access Service 201-4,000 kW							
Secondary	485-S	224	493,315	$12,127,913	$9,774,117	($2,353,796)	
Primary	485-P	55	341,815	$7,509,500	$5,850,198	($1,659,302)	
Direct Access Service > 4 MW							
Secondary	489-S	0	0	$0			
Primary	489-P	16	1,057,666	$20,790,410	$11,196,257	($9,594,153)	
Subtransmission	489-T	3	266,569	$1,634,041	$1,282,633	($351,408)	
New Load Direct Access Service > 10MW							
Primary	689-P	1	37,473	$591,195	$468,982	($122,212)	
DIRECT ACCESS TOTALS		299	2,196,838	42,653,058	28,572,187	($14,080,871)	
COS AND DA CYCLE TOTALS		920,598	20,653,161	$2,009,483,103	$2,058,635,804	$49,152,702	2.4%

December 28, 2021

To: Jesse O. Gorsuch
Alliance of Western Energy Consumers

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 394
PGE Response to AWEC Data Request 329
Dated December 21, 2021

Request:

Please refer to PGE / 500 Bekkedahl – McFarland / 9 and PGE / 601 Salmi Klotz / 27 to 31. Please provide the following data by year and Demand Response Program:

a. Total cost of program by FERC account.
b. Incentives paid.
c. Date of each curtailment event and total peak load reduction achieved.
d. Number of customers and MW enrolled by schedule.
e. Please also refer to Staff/1400, St. Brown/16. Please provide the components of the Touchstone that are necessary to implement the demand response program.

Response:

a. All deferred demand response costs are charged to FERC Account 182.3 (Other Regulatory Assets). Please see Confidential Attachment 329-A for the most recently submitted deferral application budgets and actuals.
b. Please see Confidential Attachment 329-A for the incentive costs as most recently submitted in the deferral applications.
c. Please see Confidential Attachment 329-A for preliminary data.
d. Please see Confidential Attachment 329-A for preliminary data.
e. PGE assumes this request refers to the Customer Touchpoints project as there is no Touchstone project. PGE had demand response (DR) pilots operating prior to the implementation of Customer Touchpoints. Consequently, Customer Touchpoints was not “necessary” to implement demand response. Instead, Customer Touchpoints allowed certain DR pilots to be expanded to DR programs with enhanced pricing options and at lower cost than with the legacy systems. See also PGE’s response to AWEC Data Request No. 331 for additional information.

Attachment 329-A contains protected information and is subject to General Protective Order No. 21-206.

Pages 7 – 11 of Exhibit AWEC/401 include Protected Information Subject to Order No. 21-206 and have been redacted in their entirety.

December 28, 2021

To: Jesse O. Gorsuch
Alliance of Western Energy Consumers

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 394
PGE Response to AWEC Data Request 330
Dated December 21, 2021

Request:

Please provide the stipulated revenue requirement associated with the Touchstone project.

Response:

PGE objects to this request on the basis that it is vague and ambiguous. First, PGE assumes this request refers to the Customer Touchpoints project as there is no Touchstone project. Second, PGE is not aware of the Customer Touchpoints project being a stipulated item in either Docket UE 335 or UE 394. Subject to and without waving its objection, PGE responds as follows:

Attachment 330-A provides the revenue requirement for the Customer Touchpoints capital as of April 30, 2022, the date on which PGE's UE 394 rate base is established. The revenue requirement is also based on the cost of capital as determined in the first partial stipulation filed in Docket UE 394.

Portland General Electric Company
Customer Touchpoints Revenue Requirement
Dollars in $000s

	Based on UE 394 Annual RevReq
1 Sales to Consumers	24,375
2 Sales for Resale	
3 Other Revenues	
4 Total Operating Revenues	24,375
5 Net Variable Power Costs	
6 Production O&M (excludes Trojan)	
7 Trojan O&M	
8 Transmission O&M	
9 Distribution O&M	
10 Customer & MBC O&M	
11 Uncollectibles Expense	80
12 OPUC Fees	99
13 A&G, Ins/Bene., & Gen. Plant	
14 Total Operating & Maintenance	178
15 Depreciation	709
16 Amortization	14,685
17 Property Tax	1,329
18 Payroll Tax	
19 Other Taxes	
20 Franchise Fees	623
21 Utility Income Tax	1,662
22 Total Operating Expenses & Taxes	19,188
23 **Utility Operating Income**	5,188
24 **Rate Base**	
25 Gross Plant	152,284
26 Accum. Deprec. / Amort	(60,600)
27 Accum. Def Tax	(16,281)
28 Accum. Def ITC	
29 **Net Utility Plant**	75,403
30 Misc. Deferred Debits	
31 Operating Materials & Fuel	
32 Misc. Deferred Credits	-
33 Working Cash	746
34 **Rate Base**	76,150
35 **Rate of Return**	6.812%
36 **Implied Return on Equity**	9.500%
37 Effective Cost of Debt	4.125%
38 Effective Cost of Preferred	0.000%
39 Debt Share of Cap Structure	50.000%
40 Preferred Share of Cap Structure	0.000%
41 Weighted Cost of Debt	2.063%
42 Weighted Cost of Preferred	0.000%
43 Equity Share of Cap Structure	50.000%
44 State Tax Rate	7.594%
45 Federal Tax Rate	21.000%
46 Composite Tax Rate	27.000%
47 Bad Debt Rate	0.326%
48 Franchise Fee Rate	2.556%
49 Working Cash Factor	3.891%
50 Gross-Up Factor	1.370
51 ROE Target	9.500%
52 Grossed-Up COC	8.569%
53 OPUC Fee Rate	0.406%
Utility Income Taxes	
54 Book Revenues	24,375
55 Book Expenses	17,526
56 Interest Deduction	1,571
57 Production Deduction	
58 Permanent Ms	(877)
59 Deferred Ms	(15,805)
60 Taxable Income	21,962
61 Current State Tax	1,668
62 State Tax Credits	
63 Net State Taxes	1,668
64 Federal Taxable Income	20,294
65 Current Federal Tax	4,262
66 Federal Tax Credits	
67 Excess ADIT Reversal (ARAM)	
68 Deferred Taxes	(4,267)
69 Total Income Tax Expense	1,662
70 Regulated Net Income	3,617
71 Check Regulated NI	3,617

December 28, 2021

To: Jesse O. Gorsuch
Alliance of Western Energy Consumers

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 394
PGE Response to AWEC Data Request 333
Dated December 21, 2021

Request:

Please refer to PGE / 2200, Macfarlane – Tang / 4:22-23. Please refer to PGE's 2019 Integrated Resource Plan ("IRP"), Chapter 6, which identifies various benefits of renewable resources including PTCs, energy value, capacity value, and flexibility value. Does PGE believe that the 2019 IRP does not adequately account for flexibility, capacity, and other benefits of renewable resources?

Response:

As PGE stated in PGE Exhibit 2200/5 lines 16-17, the generation marginal cost study is a simplified model and does not include all of the benefits associated with the renewable resource. The benefits identified in PGE's 2019 IRP accounted for the benefits PGE identified at the time.

December 28, 2021

To: Jesse O. Gorsuch
Alliance of Western Energy Consumers

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 394
PGE Response to AWEC Data Request 335
Dated December 21, 2021

Request:

Please refer to PGE / 2200, Macfarlane – Tang /5:15-16. Please refer to PGE's 2019 IRP, Figure 6-3. Does PGE agree that Figure 6-3 provides a reasonable representation of the capacity contribution of wind? If no, why not?

Response:

No. PGE's most recent update of the capacity contribution of wind is included in its 2019 IRP update, Figure 15. The IRP update included new resources added after the initial 2019 IRP was prepared.

December 28, 2021

To: Jesse O. Gorsuch
Alliance of Western Energy Consumers

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 394
PGE Response to AWEC Data Request 336
Dated December 21, 2021

Request:

Please refer to PGE / 200 workpaper "2022 Unbundled ROO Initial_Separate Colstrip.xlsx" sheet "Unbundled" Rows 4793 and 4679.

a. Please confirm that PGE unbundles both 9030001 and 9050001 costs for Department 432: Customer Contact Operations to Other Consumer Costs.
b. Please refer to PGE / 2200, Macfarlane – Tang /6:20-23, which states that account 9030001, Department 432: Customer Contact Operations costs are "part of the Billing costs." Please clarify whether PGE considers these cost to be part of billing costs when they are unbundled to other consumer costs.

Response:

a. Yes.
b. PGE considers these part of Other Consumer costs. PGE inadvertently included them as a Billing cost in the customer marginal cost study as it did in its previous general rate case, UE 335.

December 28, 2021

To: Jesse O. Gorsuch
Alliance of Western Energy Consumers

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 394
PGE Response to AWEC Data Request 337
Dated December 21, 2021

Request:

Please refer to PGE / 2200 Macfarlane – Tang / 7:1.

a. Please explain what Department 881: Government Affairs costs are charged to account 9050001 and why these costs are charged to 9050001.

b. If account 9050001 Department 881: Government Affairs costs are considered indirect costs, why does PGE unbundle 100% of these costs to other consumer costs?

Response:

a. The costs of addressing the needs of PGE's low income and special needs customers are charged to this account. They are charged to 9050001 as they fall under the definition of FERC account 905 - Miscellaneous customer accounts expenses.

b. These are not considered indirect costs. They are directly charged for 9050001, as they are for the specific purpose mentioned in part (a), which is classified as an Other Consumer cost in PGE's unbundling functionalization.

December 29, 2021

To: Jesse O. Gorsuch
Alliance of Western Energy Consumers

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 394
PGE Response to AWEC Data Request 338
Dated December 21, 2021

Request:

Please refer to Exhibit AWEC/205. For each of the following costs, please 1) indicate whether PGE considers the costs to be indirect, and 2) if indirect, explain why PGE considers the costs to be indirect. If direct, please explain why PGE does not support inclusion of the costs in a customer marginal cost model.

a. 401: Business Customer Contact Ops Account 9030001
b. 404: Customer Services Ops Admin Account 9030001
c. 432: Customer Contact Operations Account 9030001
d. 472: OPS Performance Solutions Account 9030001
e. 536: Customer Analytics Account 9030001
f. 567: Customer Digital Channels Account 9030001
g. 692: Cust Tech QA Automation Account 9030001
h. 694: Cust Tech Digital Account 9030001
i. 695: Cust Tech Apps Shared Serv Account 9030001
j. 697: Cust Tech Apps Back Office Account 9030001
k. 698: Cust Tech Apps Call Centr & BP Account 9030001
l. 831: DCIO Customer Strategy & Ops Account 9030001
m. 924: Customer Specialized Programs Account 9030001
n. 979: Information Tech Transfers Account 9030001
o. 555: VP, Customer Solutions Account 9050001
p. 881: Government Affairs Account 9050001
q. 495: Energy Efficiency Outreach Account 9080001
r. 532: Product Portfolio Management Account 9080001
s. 533: Product Development Account 9080001
t. 534: Product Marketing Account 9080001
u. 538: Residential Marketing P.O. Account 9080001
v. 881: Government Affairs Account 9080001
w. 979: Information Tech Transfers Account 9080001

Response:

a. 401: Business Customer Contact Ops Account 9030001 – Direct to Other Consumer. Currently allocated to Billing in customer marginal cost model, allocating to Other Consumer is appropriate.
b. 404: Customer Services Ops Admin Account 9030001 – Direct to Other Consumer. Currently allocated to Billing in customer marginal cost model, allocating to Other Consumer is appropriate.
c. 432: Customer Contact Operations Account 9030001 – Direct to Other Consumer. Currently allocated to Billing in customer marginal cost model, allocating to Other Consumer is appropriate.
d. 472: OPS Performance Solutions Account 9030001 – Direct to Other Consumer. Currently allocated to Billing in customer marginal cost model, allocating to Other Consumer is appropriate.
e. 536: Customer Analytics Account 9030001 – Direct to Other Consumer. Adding this to and allocating to Other Consumer in the customer marginal cost model is appropriate.
f. 567: Customer Digital Channels Account 9030001 – Direct to Other Consumer. Currently allocated to Billing in customer marginal cost model, allocating to Other Consumer is appropriate.
g. 692: Cust Tech QA Automation Account 9030001 – Direct to Other Consumer. Adding this to and allocating to Other Consumer in the customer marginal cost model is appropriate.
h. 694: Cust Tech Digital Account 9030001 – Direct to Other Consumer. Adding this to and allocating to Other Consumer in the customer marginal cost model is appropriate.
i. 695: Cust Tech Apps Shared Serv Account 9030001 – Direct to Other Consumer. Adding this to and allocating to Other Consumer in the customer marginal cost model is appropriate.
j. 697: Cust Tech Apps Back Office Account 9030001 – Direct to Other Consumer. Adding this to and allocating to Other Consumer in the customer marginal cost model is appropriate.
k. 698: Cust Tech Apps Call Centr & BP Account 9030001 – Direct to Other Consumer. Adding this to and allocating to Other Consumer in the customer marginal cost model is appropriate.
l. 831: DCIO Customer Strategy & Ops Account 9030001 – Direct to Other Consumer. Adding this to and allocating to Other Consumer in the customer marginal cost model is appropriate.
m. 924: Customer Specialized Programs Account 9030001 – Direct to Production (Operating Unit 14300, Distributed Generation) and Other Consumer (Operating Unit 18100, PGE General Operations). Adding this to and allocating to Other Consumer in the customer marginal cost model is appropriate.
n. 979: Information Tech Transfers Account 9030001 – Indirect, allocated to Billing and Other Consumer. RC 979 is purely an allocation account that handles the IT service provider allocation activity and therefore the costs are indirect.
o. 555: VP, Customer Solutions Account 9050001 – Direct to Other Consumer. Adding this to and allocating to Other Consumer in the customer marginal cost model is appropriate.

p. 881: Government Affairs Account 9050001 – Direct to Other Consumer. Adding this to and allocating to Other Consumer in the customer marginal cost model is appropriate.
q. 495: Energy Efficiency Outreach Account 9080001 – Direct to Other Consumer. Adding this to and allocating to Other Consumer in the customer marginal cost model is appropriate.
r. 532: Product Portfolio Management Account 9080001 – Direct to Other Consumer. Adding this to and allocating to Other Consumer in the customer marginal cost model is appropriate.
s. 533: Product Development Account 9080001 – Direct to Other Consumer. Adding this to and allocating to Other Consumer in the customer marginal cost model is appropriate.
t. 534: Product Marketing Account 9080001 – Direct to Other Consumer. Adding this to and allocating to Other Consumer in the customer marginal cost model is appropriate.
u. 538: Residential Marketing P.O. Account 9080001 – Direct to Other Consumer. Adding this to and allocating to Other Consumer in the customer marginal cost model is appropriate.
v. 881: Government Affairs Account 9080001 – Direct to Other Consumer. Adding this to and allocating to Other Consumer in the customer marginal cost model is appropriate.
w. 979: Information Tech Transfers Account 9080001 – Indirect, allocated to Billing and Other Consumer. RC 979 is purely an allocation account that handles the IT service provider allocation activity and therefore the costs are indirect.

PGE inadvertently missed the inclusion of a number of direct costs above in its marginal cost study due to changes in methodology between the current general rate case, UE 394, and its previous general rate case, UE 335. In addition, a large number of the costs above should be allocated to Other Consumer but are currently allocated to Billing.

January 11, 2022

To: Corinne O. Milinovich
Alliance of Western Energy Consumers

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 394
PGE Response to AWEC Data Request 343
Dated January 4, 2022

Request:

Does PGE expect resource adequacy efforts to reduce PGE's planning reserve margin? If yes, when would PGE implement a reduced planning reserve?

Response:

PGE clarifies that its resource adequacy model Sequoia does not calculate capacity need based on a prescribed planning reserve margin. Rather, the model calculates the amount of incremental capacity needed to achieve a targeted reliability metric.

For further detail, see PGE's Response to AWEC Data Request 341. The Northwest Power Pool (NWPP) Western Resource Adequacy Program (WRAP) is in a non-binding phase and indicative information on future planning reserve margins is not yet available. The binding phases of the NWPP WRAP are not planned to commence until 2023 and beyond. The impending future retirement of several thermal generators within and outside the region, mixed with increasing variable energy resource and the effects of a changing climate, has led to resource adequacy efforts to explore whether the region will continue to have an adequate supply of electricity during critical hours. These resource adequacy efforts aim to improve the reliability of supply to meet load. Participation in these efforts could drive investment cost savings by virtue of sharing resources across a broad footprint during this transition of the regional power system.

Date: January 6, 2022

TO:
DAVISON VAN CLEVE PC
ATTORNEYS AT LAW
1750 SW HARBOR WAY SUITE 450
PORTLAND, OR 97201

FROM: Max St. Brown
Renewable Resource Analyst
Utility Strategy and Integration Division

OREGON PUBLIC UTILITY COMMISSION
Docket No. UE 394
First Set Data Request filed December 30, 2021

AWEC Data Request No 04:

04. Please refer to Staff/1400, St. Brown/13:15-17.

a. How does Staff define reserve margin in this context?
b. Does Staff differentiate between reserve margin and reserve required to be held? If yes, what is the difference?
c. Please provide all analysis performed by Staff to determine that a reserve margin of 10 percent is a prudent level of reserves when selecting an optimal mix of new generating facilities.
d. What level of reserves is PGE currently required to hold?
e. What resource adequacy efforts are expected to reduce PGE's held reserves?
f. Does Staff agree that PGE should be capable of meeting reserve requirements even in the face of abnormal weather or other load events? If no, why not?
g. Does Staff agree that PGE should be capable of meeting reserve requirements in the presence of a severe contingency event such as a prolonged outage of Carty? If no, why not?
h. Please provide the expected decrease in reserve required to be held because of resource adequacy efforts.
i. What is Staff's basis for using a 10 percent reserve margin rather than 9 or 11 percent?
j. Was Staff's recommended 10 percent reserve margin developed with PGE's current resource mix in mind? If no, what resource mix was

assumed when developing the recommendation for a 10 percent reserve margin?

k. Was Staff's recommended 10 percent reserve margin developed with regional resources and loads other than PGE in mind?

<u>OPUC Response No 04</u>:

04.

a. Staff defines reserve margin in this context as the value PGE work paper "MC gen 2022 SDEC20E22 Final_CONF.xlsx," tab "Nominal Prices," row 42. When this value decreases, PGE's SCCT cost to input into the marginal cost of service study decreases. PGE's use of "operating reserve margin" in its response to Staff DR 955 is also influential to Staff's definition in this context. "PGE defines the system actual reserve margin as the operating reserves divided by load at any given point in time."[1] And note that PGE excludes renewable generation from operating reserves.[2]
b. Yes. Staff differentiates between planning reserve margin and operating reserve margin. "Generally, operating reserve margin is lower than planning reserve, since at any given time, some generation units are not available."[3] Staff was not able to find a standard definition of the term "reserves required to be held."
c. Staff considered achieved reserve margins and anticipated efficiency gains from resource adequacy efforts. For achieved reserve margins see PGE's response to Staff DR 956.
d. Please see the response to part b.
e. A resource adequacy effort that Staff expects to reduce PGE's held reserves is the Northwest Power Pool's resource adequacy program. See for example, "may enable a lower reserve margin because large systems are less vulnerable to individual, large contingencies."[4]
f. Yes.
g. Yes.
h. Staff has proposed to adjust the reserve margin from 12 percent to 10 percent. Staff's recommendation for a 10 percent reserve margin is also informed by PGE's modeling of an SCCT as the capacity resource instead of modeling a non-emitting resource.

---

1 PGE's response to Staff DR 955.

2 PGE's response to Staff DR 957.

3 Quotation of Dr. Ross Baldick in Jaclyn Brandt, "ERCOT facing low reserve margins to meet peak electricity demand this summer," July 9, 2019, available at https://dailyenergyinsider.com/featured/20357-ercot-facing-low-reserve-margins-to-meet-peak-electricity-demand-this-summer/

4 Northwest PowerPool, "Agenda for Dynamics of Today's Energy System A Resource Adequacy Symposium," October 2, 2019, available at: https://www.nwpp.org/private-media/documents/2019.10.02_Resource_Adequacy_Symposium_ALL_SLIDES.pdf

i. In UE 335 Staff described a 10 percent reserve margin as more realistic.[5] Furthermore, 10 percent is the bottom of the range of an older study: "reliable system operation requires a net reserve margin (native generation plus contracted imports) of 10 to 15 percent." [6] An older study might be relevant because of the modeling of an SCCT instead of a non-emitting resource.

j. Staff's recommended 10 percent reserve margin was developed with the resource mix contemplated in PGE's marginal cost study in mind.

k. Please see the response to parts i and j.

[5] UE 335, Staff/900, Compton/4, line 1.

[6] DOE, "Electricity Reliability Impacts of a Mandatory Cooling Tower Rule for Existing Steam Generation Units," October 2008, page 29, available at https://www.energy.gov/sites/prod/files/oeprod/DocumentsandMedia/Cooling_Tower_Report.pdf

Date: January 6, 2022

TO:
DAVISON VAN CLEVE PC
ATTORNEYS AT LAW
1750 SW HARBOR WAY SUITE 450
PORTLAND, OR 97201

FROM: Max St. Brown
Renewable Resource Analyst
Utility Strategy and Integration Division

OREGON PUBLIC UTILITY COMMISSION
Docket No. UE 394
First Set Data Request filed December 30, 2021

AWEC Data Request No 05:

05. Please refer to Staff/1400, St. Brown/14:7-11.

a. Does Staff's recommendation presume capacity resources can make energy sales to wholesale markets when not needed to serve capacity needs?
b. Does Staff agree that if CCCTs make off-system sales, it is reasonable to use net revenue to reduce the long-run cost of operating a CCCT? If no, why not?

OPUC Response No 05:

05.

a. Yes.
b. Yes.

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UE 394

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

EXHIBIT AWEC/402

MARGINAL COST AND RATE SPREAD

TABLE 3
PORTLAND GENERAL ELECTRIC
ESTIMATED EFFECT ON CONSUMERS' TOTAL ELECTRIC BILLS AWEC REPLY
UE335 to 2022

CATEGORY	RATE SCHEDULE	CUSTOMERS (Forecast SSEP21E22)	MWH SALES	TOTAL ELECTRIC BILLS: UE 335 Rates all supplementals except LIA, PPC & Sch 109	TOTAL ELECTRIC BILLS: PROPOSED all supplementals except LIA, PPC & Sch 109	Change AMOUNT	Change PCT.
Residential	7	808,245	7,569,338	$928,099,756	$1,061,306,555	$133,206,798	14.4%
Employee Discount				($1,110,239)	($1,172,801)	($62,562)	
Subtotal				$926,989,517	$1,060,133,753	$133,144,236	14.4%
Outdoor Area Lighting	15	0	13,922	$3,038,151	$3,121,277	$83,126	2.7%
General Service <30 kW	32	94,547	1,588,439	$183,912,419	$215,069,747	$31,157,328	16.9%
Opt. Time-of-Day G.S. >30 kW	38	376	27,371	$3,656,008	$4,065,805	$409,796	11.2%
Irrig. & Drain. Pump. < 30 kW	47	2,644	19,423	$3,780,692	$4,173,435	$392,743	10.4%
Irrig. & Drain. Pump. > 30 kW	49	1,449	62,083	$8,634,342	$10,623,862	$1,989,520	23.0%
General Service 31-200 kW	83	11,463	2,870,308	$266,001,667	$294,834,763	$28,833,097	10.8%
General Service 201-4,000 kW							
Secondary	85-S	1,190	2,074,462	$166,795,555	$167,674,492	$878,937	0.5%
Primary	85-P	171	570,537	$42,335,768	$43,195,924	$860,157	2.0%
Schedule 89 > 4 MW							
Secondary	89-S	3	95,807	$6,197,894	$6,335,030	$137,136	2.2%
Primary	89-P	15	639,544	$40,493,995	$41,373,419	$879,424	2.2%
Subtransmission	89-T/75-T	5	51,499	$4,015,478	$4,056,705	$41,227	1.0%
Schedule 90	90-P	6	2,827,139	$164,305,158	$167,195,232	$2,890,074	1.8%
Street & Highway Lighting	91/95	185	43,876	$9,684,133	$10,640,115	$955,982	9.9%
Traffic Signals	92	0	2,576	$214,993	$186,296	($28,697)	-13.3%
COS TOTALS		920,299	18,456,323	$1,830,055,770	$2,032,679,857	$202,624,086	11.1%
Direct Access Service 201-4,000 kW							
Secondary	485-S	224	493,315	$12,510,200	$8,508,047	($4,002,153)	
Primary	485-P	55	341,815	$6,513,336	$5,298,900	($1,214,437)	
Direct Access Service > 4 MW							
Secondary	489-S	0	0	$0			
Primary	489-P	16	1,057,666	$10,783,289	$10,430,954	($352,335)	
Subtransmission	489-T	3	266,569	$0	$1,208,473	$1,208,473	
New Load Direct Access Service > 10MW							
Primary	689-P	1	37,473	$266,934	$444,262	$177,328	
DIRECT ACCESS TOTALS		299	2,196,838	30,073,760	25,890,637	($4,183,124)	
COS AND DA CYCLE TOTALS		920,598	20,653,161	$1,860,129,531	$2,058,570,493	$198,440,963	10.7%

TABLE 3
PORTLAND GENERAL ELECTRIC
ESTIMATED EFFECT ON CONSUMERS' TOTAL ELECTRIC BILLS AWEC REPLY
2022

CATEGORY	RATE SCHEDULE	Forecast SSEP21E22 CUSTOMERS	MWH SALES	TOTAL ELECTRIC BILLS CURRENT all supplementals except LIA, PPC & Sch 109	TOTAL ELECTRIC BILLS PROPOSED all supplementals except LIA, PPC & Sch 109	Change AMOUNT	Change PCT.
Residential	7	808,245	7,569,338	$989,799,621	$1,061,306,555	$71,506,934	7.2%
Employee Discount				($1,110,239)	($1,172,801)	($62,562)	
Subtotal				$988,689,382	$1,060,133,753	$71,444,372	7.2%
Outdoor Area Lighting	15	0	13,922	$3,117,688	$3,121,277	$3,590	0.1%
General Service <30 kW	32	94,547	1,588,439	$198,672,623	$215,069,747	$16,397,124	8.3%
Opt. Time-of-Day G.S. >30 kW	38	376	27,371	$3,823,161	$4,065,805	$242,644	6.3%
Irrig. & Drain. Pump. < 30 kW	47	2,644	19,423	$3,952,188	$4,173,435	$221,247	5.6%
Irrig. & Drain. Pump. > 30 kW	49	1,449	62,083	$9,174,867	$10,623,862	$1,448,995	15.8%
General Service 31-200 kW	83	11,463	2,870,308	$287,568,509	$294,834,763	$7,266,254	2.5%
General Service 201-4,000 kW							
Secondary	85-S	1,190	2,074,462	$180,149,934	$167,674,492	($12,475,441)	-6.9%
Primary	85-P	171	570,537	$45,903,546	$43,195,924	($2,707,622)	-5.9%
Schedule 89 > 4 MW							
Secondary	89-S	3	95,807	$6,817,660	$6,335,030	($482,630)	-7.1%
Primary	89-P	15	639,544	$44,267,613	$41,373,419	($2,894,194)	-6.5%
Subtransmission	89-T/75-T	5	51,499	$4,322,637	$4,056,705	($265,932)	-6.2%
Schedule 90	90-P	6	2,827,139	$180,212,670	$167,195,232	($13,017,438)	-7.2%
Street & Highway Lighting	91/95	185	43,876	$9,927,744	$10,640,115	$712,372	7.2%
Traffic Signals	92	0	2,576	$229,824	$186,296	($43,527)	-18.9%
COS TOTALS		920,299	18,456,323	$1,966,830,044	$2,032,679,857	$65,849,812	3.3%
Direct Access Service 201-4,000 kW							
Secondary	485-S	224	493,315	$12,127,913	$8,508,047	($3,619,866)	
Primary	485-P	55	341,815	$7,509,500	$5,298,900	($2,210,600)	
Direct Access Service > 4 MW							
Secondary	489-S	0	0	$0			
Primary	489-P	16	1,057,666	$20,790,410	$10,430,954	($10,359,456)	
Subtransmission	489-T	3	266,569	$1,634,041	$1,208,473	($425,568)	
New Load Direct Access Service > 10MW							
Primary	689-P	1	37,473	$591,195	$444,262	($146,932)	
DIRECT ACCESS TOTALS		299	2,196,838	42,653,058	25,890,637	($16,762,421)	
COS AND DA CYCLE TOTALS		920,598	20,653,161	$2,009,483,103	$2,058,570,493	$49,087,391	2.4%

PORTLAND GENERAL ELECTRIC
2022 MARGINAL ENERGY AND CAPACITY COSTS - AWEC REPLY

Year	Thermal Capacity SCCT $/kW-year	Hydro Capacity Pump Storage $/kW-year	Thermal Marginal Energy $/MWh	Wind Marginal Energy $/MWh	RPS	Capacity Costs $/kW-year	Weighted Marginal Energy $/MWh
2022	90.63	238.32	29.40	37.51	20.00%	120.17	31.02
2023	92.44	243.09	29.99	38.26	20.00%	122.57	31.64
2024	94.28	247.95	30.59	39.02	20.00%	125.02	32.27
2025	96.17	252.90	31.20	39.80	27.00%	138.49	33.52
2026	98.09	257.95	31.82	40.60	27.00%	141.25	34.19
2027	100.05	263.11	32.46	41.41	27.00%	144.08	34.87
2028	102.05	268.37	33.11	42.24	27.00%	146.96	35.57
2029	104.09	273.73	33.77	43.08	27.00%	149.89	36.28
2030	106.17	279.20	34.44	43.94	35.00%	166.73	37.77
2031	108.29	284.78	35.13	44.82	35.00%	170.06	38.52
2032	110.46	290.47	35.83	45.72	35.00%	173.46	39.29
2033	112.66	296.28	36.55	46.63	35.00%	176.93	40.08
2034	114.91	302.20	37.28	47.56	35.00%	180.46	40.88
2035	117.21	308.24	38.02	48.51	45.00%	203.17	42.74
2036	119.55	314.40	38.78	49.48	45.00%	207.23	43.60
2037	121.94	320.68	39.56	50.47	45.00%	211.38	44.47
2038	124.38	327.09	40.35	51.48	45.00%	215.60	45.36
2039	126.87	333.63	41.16	52.51	45.00%	219.91	46.26
2040	129.40	340.29	41.98	53.56	50.00%	234.85	47.77
2041	131.99	347.09	42.82	54.63	0.00%	131.99	42.82
Real Levelized	$90.63	$238.32	$29.40	$37.51		$136.06	$31.89
NPV	$1,158	$3,046	$376	$479		$1,739	$408
Nominal Levelized	$105.65	$277.83	$34.27	$43.72		$158.61	$37.18
Real Levelized	$90.63	$238.32	$29.40	$37.51		$136.06	$31.89

SUMMARY OF OTHER CONSUMER MARGINAL COSTS

SCHEDULE	DESCRIPTION	PGE	AWEC	AWEC Reply
Schedule 7	Residential	$ 19.61	$ 65.58	$ 56.82
Schedule 15	Residential - Area Lights	$ 9.43	$ 47.60	$ 38.85
Schedule 15	Commercial - Area Lights	$ 9.43	$ 43.64	$ 34.62
Schedule 32	Small Non-Residential (< 30 kW)	$ 20.93	$ 63.05	$ 54.03
Schedule 38	Large Non-Residential Time-of-Use	$ 24.59	$ 241.06	$ 232.04
Schedule 47	Small Irrigation	$ 18.75	$ 60.72	$ 51.70
Schedule 49	Large Irrigation	$ 18.96	$ 236.05	$ 227.03
Schedule 83	Large Non-Residential (31-200 kW)	$ 129.63	$ 347.45	$ 338.43
Schedule 85	Large Non-Residential (201-1,000 kW)	$ 1,052.74	$ 1,263.99	$ 1,254.97
Schedule 89	Large Non-Residential (> 4,000 kW)	$ 6,918.81	$ 7,133.00	$ 7,123.98
Schedule 90	Large Non-Residential (>4,000 kW and Aggregate to >100 aMW)	$ 42,702.19	$ 42,912.41	$ 42,903.39
Schedule 91 & 95	Street and Highway Lighting	$ 9.43	$ 72.77	$ 63.75
Schedule 92	Traffic Sign. & Comm. Dev.	$ 9.43	$ 66.17	$ 57.15

TABLE 3
PORTLAND GENERAL ELECTRIC
ESTIMATED EFFECT ON CONSUMERS' TOTAL ELECTRIC BILLS
PGE Proposed Rate Spread

CATEGORY	RATE SCHEDULE	CUSTOMERS (Forecast SSEP21E22)	MWH SALES	TOTAL ELECTRIC BILLS CURRENT all supplementals except LIA, PPC & Sch 109	TOTAL ELECTRIC BILLS PROPOSED all supplementals except LIA, PPC & Sch 109	Change AMOUNT	Change PCT.
Residential	7	808,245	7,569,338	$928,099,756	$1,037,507,051	$109,407,295	11.8%
Employee Discount				($1,110,239)	($1,145,856)	($35,617)	
Subtotal				$926,989,517	$1,036,361,195	$109,371,678	11.8%
Outdoor Area Lighting	15	0	13,922	$3,038,151	$3,284,165	$246,014	8.1%
General Service <30 kW	32	94,547	1,588,439	$183,912,419	$212,406,502	$28,494,083	15.5%
Opt. Time-of-Day G.S. >30 kW	38	376	27,371	$3,656,008	$3,997,652	$341,643	9.3%
Irrig. & Drain. Pump. < 30 kW	47	2,644	19,423	$3,780,692	$4,147,603	$366,911	9.7%
Irrig. & Drain. Pump. > 30 kW	49	1,449	62,083	$8,634,342	$9,742,289	$1,107,947	12.8%
General Service 31-200 kW	83	11,463	2,870,308	$266,001,667	$297,532,853	$31,531,186	11.9%
General Service 201-4,000 kW							
Secondary	85-S	1,190	2,074,462	$166,795,555	$176,368,221	$9,572,666	5.7%
Primary	85-P	171	570,537	$42,335,768	$45,048,803	$2,713,035	6.4%
Schedule 89 > 4 MW							
Secondary	89-S	3	95,807	$6,197,894	$6,646,791	$448,896	7.2%
Primary	89-P	15	639,544	$40,493,995	$43,311,103	$2,817,108	7.0%
Subtransmission	89-T/75-T	5	51,499	$4,015,478	$4,304,933	$289,454	7.2%
Schedule 90	90-P	6	2,827,139	$164,305,158	$176,181,379	$11,876,221	7.2%
Street & Highway Lighting	91/95	185	43,876	$9,684,133	$10,537,007	$852,873	8.8%
Traffic Signals	92	0	2,576	$214,993	$193,123	($21,870)	-10.2%
COS TOTALS		920,299	18,456,323	$1,830,055,770	$2,030,063,617	$200,007,847	10.9%
Direct Access Service 201-4,000 kW							
Secondary	485-S	224	493,315	$12,510,200	$9,774,117	($2,736,083)	
Primary	485-P	55	341,815	$6,513,336	$5,850,198	($663,138)	
Direct Access Service > 4 MW							
Secondary	489-S	0	0	$0			
Primary	489-P	16	1,057,666	$10,783,289	$11,196,257	$412,967	
Subtransmission	489-T	3	266,569	$0	$1,282,633	$1,282,633	
New Load Direct Access Service > 10MW							
Primary	689-P	1	37,473	$266,934	$468,982	$202,048	
DIRECT ACCESS TOTALS		299	2,196,838	30,073,760	28,572,187	($1,501,573)	
COS AND DA CYCLE TOTALS		920,598	20,653,161	$1,860,129,531	$2,058,635,804	$198,506,273	10.7%

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UE 394

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

EXHIBIT AWEC/403

BETWEEN RATE CASE IMPACTS BY SCHEDULE

TABLE 3
PORTLAND GENERAL ELECTRIC
ESTIMATED EFFECT ON CONSUMERS' TOTAL ELECTRIC BILLS
UE 335 to Current Rates

CATEGORY	RATE SCHEDULE	Forecast SSEP21E22 CUSTOMERS	MWH SALES	TOTAL ELECTRIC BILLS UE 335 all supplementals except LIA, PPC & Sch 109	TOTAL ELECTRIC BILLS CURRENT all supplementals except LIA, PPC & Sch 109	Change AMOUNT	Change PCT.
Residential	7	808,245	7,569,338	$928,099,756	$989,799,621	$61,699,865	6.6%
Employee Discount				($1,110,239)	($1,110,239)	$0	
Subtotal				$926,989,517	$988,689,382	$61,699,865	6.7%
Outdoor Area Lighting	15	0	13,922	$3,038,151	$3,117,688	$79,537	2.6%
General Service <30 kW	32	94,547	1,588,439	$183,912,419	$198,672,623	$14,760,204	8.0%
Opt. Time-of-Day G.S. >30 kW	38	376	27,371	$3,656,008	$3,823,161	$167,152	4.6%
Irrig. & Drain. Pump. < 30 kW	47	2,644	19,423	$3,780,692	$3,952,188	$171,496	4.5%
Irrig. & Drain. Pump. > 30 kW	49	1,449	62,083	$8,634,342	$9,174,867	$540,525	6.3%
General Service 31-200 kW	83	11,463	2,870,308	$266,001,667	$287,568,509	$21,566,843	8.1%
General Service 201-4,000 kW							
Secondary	85-S	1,190	2,074,462	$166,795,555	$180,149,934	$13,354,379	8.0%
Primary	85-P	171	570,537	$42,335,768	$45,903,546	$3,567,779	8.4%
Schedule 89 > 4 MW							
Secondary	89-S	3	95,807	$6,197,894	$6,817,660	$619,766	10.0%
Primary	89-P	15	639,544	$40,493,995	$44,267,613	$3,773,618	9.3%
Subtransmission	89-T/75-T	5	51,499	$4,015,478	$4,322,637	$307,159	7.6%
Total	89	23	786,850	50,707,367	55,407,910	4,700,542	9.3%
Schedule 90	90-P	6	2,827,139	$164,305,158	$180,212,670	$15,907,512	9.7%
Street & Highway Lighting	91/95	185	43,876	$9,684,133	$9,927,744	$243,610	2.5%
Traffic Signals	92	0	2,576	$214,993	$229,824	$14,831	6.9%
COS TOTALS		920,299	18,456,323	$1,830,055,770	$1,966,830,044	$136,774,274	7.5%
Direct Access Service 201-4,000 kW							
Secondary	485-S	224	493,315	$12,510,200	$12,127,913	($382,288)	
Primary	485-P	55	341,815	$6,513,336	$7,509,500	$996,163	
Direct Access Service > 4 MW							
Secondary	489-S	0	0	$0	$0		
Primary	489-P	16	1,057,666	$10,783,289	$20,790,410	$10,007,120	
Subtransmission	489-T	3	266,569	$0	$1,634,041	$1,634,041	
New Load Direct Access Service > 10MW							
Primary	689-P	1	37,473	$266,934	$591,195	$324,260	
DIRECT ACCESS TOTALS		299	2,196,838	30,073,760	$42,653,058	$12,579,298	
COS AND DA CYCLE TOTALS		920,598	20,653,161	$1,860,129,531	$2,009,483,103	$149,353,572	8.0%