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October 11, 2019

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

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

Re: In the Matter of PORTLAND GENERAL ELECTRIC COMPANY,
2019 Integrated Resource Plan
**Docket No. LC 73**

Dear Filing Center:

Please find enclosed the redacted version of the Alliance of Western Energy Consumers' ("AWEC") Opening Comments in the above-referenced docket.

Please note that Attachment C to AWEC's comments includes material that Portland General Electric Company has designated as Protected Information Subject to Protective Order No. 19-186. Accordingly, AWEC is submitting the confidential portion of Attachment C under seal.

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

Sincerely,

*<u>/s/ Jesse O. Gorsuch</u>*
Jesse O. Gorsuch

Enclosure

## CERTIFICATE OF SERVICE

I HEREBY CERTIFY that I have this day served the confidential portion of the **Opening Comments of the Alliance of Western Energy Consumers** upon the parties shown below by mailing copies via First Class U.S. Mail, postage prepaid.

Dated at Portland, Oregon, this 11th day of October, 2019.

Sincerely,

*/s/ Jesse O. Gorsuch*
Jesse O. Gorsuch

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**BEFORE THE PUBLIC UTILITY COMMISSION**

**OF OREGON**

**LC 73**

| | | |
|---|---|---|
| In the Matter of<br><br>PORTLAND GENERAL ELECTRIC COMPANY,<br><br>2019 Integrated Resource Plan. | )<br>)<br>)<br>)<br>)<br>)<br>) | OPENING COMMENTS OF THE ALLIANCE OF WESTERN ENERGY CONSUMERS |

## I. INTRODUCTION

Pursuant to the Administrative Law Judge's September 11, 2019 Ruling, the Alliance of Western Energy Consumers ("AWEC") submits these Opening Comments on Portland General Electric Company's ("PGE" or "Company") 2019 Integrated Resource Plan ("IRP"). AWEC makes the following recommendations for the Oregon Public Utility Commission's ("Commission") consideration: (1) reject PGE's proposal to plan for permanent direct access customers because it is inconsistent with least-cost, least-risk planning and because PGE's proposal is best considered in UM 2024; (2) decline to acknowledge PGE's Action Plan item to acquire additional resources eligible for the Renewable Portfolio Standard ("RPS"); (3) order PGE to assume the future acquisition of unbundled renewable energy certificates ("RECs") when projecting its RPS need; and (4) adopt the recommendations of Bradley Mullins with respect to PGE's capacity need.



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## II. COMMENTS

### A. PGE's Proposal to Plan for Long-Term Direct Access Customers Will Harm Direct Access and Cost-of-Service Customers

In Section 4.7.3 of its IRP, PGE requests that the Commission allow it to plan for customers currently on its Long-Term Direct Access ("LTDA") program and projected customers in its New Load Direct Access ("NLDA") program, which would require the Commission to modify or eliminate Guideline 9 of its IRP Guidelines. PGE's arguments in favor of this proposal are essentially the same as its arguments in UE 358, in which PGE's NLDA tariffs are under review. PGE argues that it is the provider of last resort for its direct access customers and allowing it to plan for these customers will ensure resource adequacy for their loads.

As the accompanying comments of Bradley Mullins demonstrate, PGE's proposal will result in substantial cost increases for direct access and cost-of-service customers, resulting in as much as $100 million in additional capacity costs, and at a levelized value that is substantially higher than the cost of PGE's existing capacity resources.[1/]

AWEC, therefore, recommends that the Commission reject PGE's request. Rather, given PGE's projected capacity deficit, it should use the room under its LTDA and NLDA programs as a means of filling this capacity. Mr. Mullins shows that this approach, which allows PGE to avoid capacity acquisitions, is a lower cost alternative to acquiring additional capacity.

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1/ Attachment B (Mullins) at 3.



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If the Commission does not reject PGE's proposal outright, then AWEC recommends that the Commission defer consideration of PGE's proposal to the ongoing process in UM 2024, the Commission's general investigation into long-term direct access programs. PGE's proposal implicates resource adequacy issues associated with direct access customers, the extent to which cost-of-service customers either benefit or are harmed by direct access, and the best way to treat direct access load for resource planning purposes to maximize these benefits and/or minimize the harms. The interrelated nature of these issues indicates that they are best addressed collectively, not in one-off proceedings like this IRP.

### B. PGE failed to comply with Commission direction regarding unbundled RECs.

In its acknowledgement order of the 2016 IRP, the Commission "direct[ed] PGE to demonstrate it has followed industry best practices for incorporating unbundled REC market projections into its least-cost, least-risk RPS compliance strategy."[2/] PGE did not do as directed; the 2019 IRP contains no discussion at all of unbundled RECs. The only mention of unbundled RECs in the IRP is in Appendix B identifying checklist items from the Commission's acknowledgement order of its 2016 IRP.[3/] Thus, the Company's RPS compliance action plan item is deficient, and the Commission should not acknowledge it.

For several years and in multiple dockets, AWEC has argued that PGE should forecast that it will procure unbundled RECs to meet a portion of its RPS compliance, and continues to recommend that the Commission order PGE to do this going forward. Simply put, forecasting unbundled RECs is part of a least-cost, least-risk plan to comply with Oregon's RPS.

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2/ LC 66, Order No. 17-386 at 20-21 (Oct. 9, 2017).
3/ PGE 2019 IRP at 241.



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Unbundled RECs are the demonstrated lowest cost means of achieving RPS compliance, but customers realize no value from PGE's procurement of these instruments if the Company does not forecast their purchase. The value they provide to customers is in their ability to defer and reduce future physical resource acquisitions that, even with the full PTC, are significantly more expensive. Moreover, in the absence of forecasting their purchase, they could provide value through a buildup of PGE's REC bank that can be used for future RPS compliance. As discussed below and by Dr. Hellman, though, the Company also eliminates this potential benefit by ignoring the REC bank in its determination of RPS needs. PGE only looks to its "physical deficiency year" (meaning the year that it would no longer be able to meet the RPS solely with RECs generated from its owned and contracted resources). This is simply imprudent planning and is contrary to customers' interests. AWEC once again recommends that the Commission require PGE to forecast the purchase of unbundled RECs when analyzing the need for a new RPS resource.

### C. PGE Should Delay Acquisition of Additional RPS Resources

PGE's Action Plan proposes to acquire an additional 150 aMW of RPS-eligible resources by 2023.[4/] AWEC opposed a similar action plan in PGE's 2016 IRP and its position on this issue has not materially changed. PGE's proposal is not based on need, but on a forecast of economic benefits over the long term and clean energy policies that are not specific to its customers or the rates they pay for utility service. PGE's own analysis shows that its RPS Action Plan will increase costs to customers in the near term (the period in which PGE's analysis is most likely to be accurate) and only see a net benefit over time, assuming PGE's power price

[4/] PGE IRP at 216.



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forecasts are accurate.[5/] Unless the Commission modifies the traditional ratemaking construct – where prudence is determined based on the information the utility had at the time it made its decision and cost recovery is effectively guaranteed upon a finding of prudence – customers bear all of the risk that PGE's economic forecasts bear out. This is a competitive market strategy, not a rate regulation strategy.

If anything, the justification for acquiring additional near-term RPS resources has become less compelling since the 2016 IRP. In the 2016 IRP, PGE had the ability to acquire resources eligible for 100% of the PTC, and forecasted a "physical" RPS compliance need in 2025. This time, PGE is looking at acquiring 60% of the PTC by the end of 2022 as a best-case scenario, and 40% if the resource it selects is online at the end of 2023, and its "physical" RPS compliance need is not until 2030.[6/]

Also like the 2016 IRP, PGE's forecasted RPS need is misleading. It is misleading on the physical compliance side because it does not account for RECs generated by the Wheatridge project between 2021 and 2025 or RECs from the repowered Farraday hydro facility, and, as Mr. Mullins shows, improperly includes customers assumed to participate in PGE's Green Energy Affinity Rider program in PGE's RPS need.[7/] Accounting for these issues would push PGE's physical RPS compliance need out at least another year.[8/]

PGE does not count the RECs associated with Wheatridge between 2021 and 2025 because it says it committed to provide the value of these RECs to customers during this

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5/ Id. at 198-99.
6/ Id. at 135, 113.
7/ Attachment B (Mullins) at 4.
8/ Attachment A (Hellman) at 1, n. 1.



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period.[9] In other words, PGE's proposal to return the value of RECs to customers also advances the time in which it needs to acquire additional RPS resources, thus partly justifying additional early action. This circular plan gives to customers in one hand and takes away from them in the other. The Commission has not approved PGE's proposal to return the value of RECs to customers, and PGE does not know what the value of these RECs will be.[10] Dr. Hellman's analysis shows that is likely to be of questionable value to customers.[11]

It is, therefore, premature to assume that these RECs will not be available for RPS compliance.

PGE's RPS need is also misleading because it does not utilize any of its substantial REC bank. As Dr. Marc Hellman shows, the REC bank is a valuable customer asset that becomes worthless to customers through PGE's IRP. Indeed, PGE has no incentive to rely on its REC bank for RPS compliance. This is for two primary reasons.

First, fully utilizing the REC bank would push PGE's RPS need out to 2036, even ignoring unbundled RECs and the RECs from Wheatridge between 2021 and 2025.[12] This diminishes the case for investing in another physical resource in the near term, which could increase returns for shareholders. PGE, however, eliminates this potential value of delaying physical compliance by forecasting the need for a new resource when it is physically RPS deficient, not when its REC bank would be exhausted.

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9/ 2019 IRP at 113, n. 114.
10/ Attachment C at 5 (PGE Response to AWEC Data Request 006).
11/ Attachment A (Hellman) at 8-9.
12/ 2019 IRP at 113.



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Second, RECs are customer property that PGE is holding on their behalf for free. RECs have clear monetary value and are akin to other assets PGE includes in rate base and on which customers pay a return to shareholders.[13/] A symmetrical treatment would offset PGE's rate base with the value of the RECs in its bank, thereby providing customers the financial benefit of these RECs. Without such a financial incentive, there is no reason for PGE ever to draw down its substantial REC bank.

Finally, as discussed above, PGE's RPS need is misleading because it does not forecast any purchases of unbundled RECs, despite the fact that PGE has satisfied 20% of its RPS obligation with unbundled RECs every year without exception. Assuming PGE continues this strategy of purchasing unbundled RECs (which AWEC believes to be prudent), PGE has no need for new RPS resources until approximately 2040.[14/]

AWEC made most of these arguments in LC 66 and sees little point in belaboring them further here. It is enough to show that circumstances have become *less* favorable for pursuing an early procurement strategy than they were in the 2016 IRP – the near-term value of renewables is lower (with a reduced PTC) and the "physical RPS deficiency date" is farther into the future. PGE does include higher capacity factor Montana wind in its analysis this time, a change from the 2016 IRP, but identifies no viable option to bring this resource to its balancing area by the end of 2023.[15/]

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13/ Attachment A (Hellman) at 7-11.

14/ With the ability to use unbundled RECs to meet 20% of RPS obligations, maximizing unbundled RECs over a five-year period pushes out PGE's compliance need by one additional year.

15/ PGE 2019 IRP at 147.



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PGE's strategy raises the question of when the economic benefits of a near-term RPS procurement are so speculative, and the need for additional RPS resources so far into the future, that a projection of benefits no longer justifies taking action. AWEC's position is that PGE has already crossed this line and should go no further. The Commission disagreed with AWEC in the 2016 IRP and authorized PGE to pursue a "glide path" strategy of RPS compliance.[16/] AWEC can accept this strategy as long as all parties agree on the assumptions that underlie the analysis of when to pursue an incremental acquisition. AWEC disagrees with PGE that the Company should identify an RPS need as the year it is physically deficient – AWEC believes PGE must make at least some provision for the value of its REC bank in deferring future resource acquisitions. AWEC also disagrees with PGE's continued disregard of the availability of unbundled RECs – AWEC believes PGE must make at least some provision for the likelihood that it will purchase unbundled RECs in the future. AWEC would appreciate clear direction from the Commission on these issues so that these disputes may be avoided in future IRPs.

**D. PGE's capacity deficit is overstated.**

PGE identifies a reference case capacity deficit of 685 MW by 2025.[17/] As Mr. Mullins discusses, however, this need is overstated for at least two reasons. First, it does not consider the capacity from the resources PGE will acquire to serve Green Energy Affinity Rider customers. Second, it assumes far less market import capability than PGE's transmission rights allow. Third, PGE is likely to meet a substantial portion of this deficit through bilateral

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16/ LC 66, Order No. 18-044 at 1 (Feb. 2, 2018).

17/ 2019 IRP at 25.



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contracting opportunities. AWEC recommends that PGE revise its capacity need to account for these issues.

Dated this 11th day of October, 2019.

Respectfully submitted,

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**Comments of Dr. Marc M. Hellman on behalf of the Alliance of Western Energy Consumers**

**Review of PGE Renewable Energy Credit Action Plan**

PGE has a significant amount of banked RECs. In response to Staff Data Request No. 22, in 2019, PGE has over 1200 AMW of RECs in the bank, potentially growing each year with additional renewable resource generation.

In Section G.4 of the 2019 PGE IRP report, PGE provides a table summarizing the yearly production of RECs along with the RPS requirement. What is interesting and evident from this table is that absent the REC Bank, PGE is able to meet its Reference Case RPS obligation just with current in-year renewable generation. This relationship holds through at least 2025, with a deficit identified for 2030.

TABLE G-4: REC production and obligation, MWa

| Need Future | 2021 | 2022 | 2023 | 2024 | 2025 | 2030 | 2035 | 2040 | 2045 | 2050 |
|---|---|---|---|---|---|---|---|---|---|---|
| **REC Production** | | | | | | | | | | |
| PGE Resources and Non-QF Contracts | 314 | 332 | 332 | 332 | 450 | 441 | 440 | 396 | 396 | 396 |
| QF Contracts | 125 | 125 | 125 | 125 | 152 | 152 | 62 | 5 | 0 | 0 |
| **Total** | **439** | **457** | **457** | **457** | **602** | **594** | **502** | **401** | **396** | **396** |
| **REC Obligation** | | | | | | | | | | |
| Low Need Future | 379 | 377 | 377 | 376 | 504 | 640 | 805 | 877 | 860 | 843 |
| Reference Case | 398 | 401 | 405 | 408 | 555 | 755 | 1020 | 1192 | 1256 | 1319 |
| High Need Future | 416 | 423 | 433 | 441 | 609 | 875 | 1234 | 1494 | 1621 | 1746 |

This relationship along with the sizeable REC Bank lends credence to the PGE finding stated on page 26 of its 2019 IRP that it can meet its RPS obligation using its current renewable resources and the REC Bank up to 2036.[1/] However, PGE does not propose in the 2019 IRP to use its REC bank in any manner for the benefit of customers.

1/ PGE currently proposes to sell the Wheatridge RECs generated for the years 2021 through 2024 and has not included in its analysis the impact of using the Wheatridge RECs produced prior to 2025 to delay the need for renewable resources. Including the Wheatridge generation from 2021 through 2024, if the Wheatridge RECs were able to be banked instead of sold, PGE can meet its RPS obligation using existing resources for one additional year – that is, the 2036 date is moved out to 2037. See Attachment C at 4 (PGE Response AWEC DR 004, Confidential Attachment A).

Instead, PGE ignores its large bank of RECs and proposes to acquire, by the end of 2023, up to 150 AMW of RPS eligible resources. PGE admits that this acquisition is not to meet near-term RPS obligations, but dismisses, based on its broad policy grounds, the potential cost-of-service rate benefits of delaying an acquisition through using its REC bank to meet RPS requirements.

On page 113 of the IRP, PGE states that using the REC bank to meet RPS obligations:

> *…would significantly delay the benefits of bringing new renewable resources onto the system. Given the intent of SB 1547, the preferences expressed by many of our customers, and our own long-term decarbonization goals, PGE does not consider such a strategy to be in the interest of our customers, the state of Oregon, or our company. PGE believes that it is appropriate to apply a minimum standard of physical RPS compliance in its long-term planning process and to use the REC bank to mitigate compliance risks…*

This discussion makes it clear that the purpose of near-term renewable resource acquisition is for non-direct cost considerations that include benefits to the State of Oregon and the Company. While this may be noble, there are several drawbacks to this largess. One drawback is that PGE will be seeking recovery of these costs from its ratepayers and PGE's ratepayers will also shoulder the risk of non-performance of the renewable projects; a second drawback is that resources are acquired well ahead of need and thus do not take advantage of future technological progress or the knowledge of actual circumstances several years hence; that is, we do not have perfect knowledge of the near future or even good knowledge of circumstances ten years hence.

In reviewing PGE's recommendations, there are two topic area questions that AWEC recommends the Commission give due consideration. The first question topic is whether the recommended IRP is least-cost/least risk. The second question topic is whether PGE customers are **currently** receiving fair value for the REC bank. Each question topic will be discussed in turn.

**Question One: Is PGE's Recommendations Least-Cost/Least Risk?**

The PGE IRP discussion, pages 31 through 34, makes clear that the proposed renewable resource acquisitions are not due to the need for renewable resources or from a cost savings perspective. The renewable resource acquisition is recommended for the sake of acquiring more renewable resources. And as noted above, a key consideration in PGE's calculation is the benefit to *non*-ratepayer interests. AWEC considers PGE to some extent to be double-counting the environmental benefits of its resource choice by both including the availability of the PTC for renewable resources coming on-line in the near-term action period as well as reaching outside the numerical results and identifying near-term renewable resource additions as warranted given public policy goals and Company policy. Presumably the PTC reflects some of the environmental (non-cost) benefits of renewable generation. The PTC provides ten years of tax credits that is a benefit for owners of renewable resources and is a cost to the federal government and taxpayers as it reduces federal tax revenue. Oregon policy certainly expands on the policy goals of the PTC by also requiring a state-mandated RPS. Even so, Oregon policy acknowledges a limit on its public policy aims by having a four percent cost cap and phasing in the percentage requirements through 2040. With the addition of another 150 AMW of renewable generation, PGE would meet approximately 35% of its load with RPS eligible resources in 2023, even though it will only be required to meet 20% of its load in this year.

What PGE has not demonstrated is why, despite the federal and state statutory mechanisms, more action benefits its customers; and that such action does not depart from least-cost least risk outcomes. Further, PGE has not demonstrated that ratepayers will experience net benefits after any value mechanism is adopted by the OPUC and implemented by PGE. AWEC notes that the "benefit" PGE is providing its support for is a benefit paid for by PGE's ratepayers. No shareholder monies are at stake.

Even though there is no demonstration that ratepayers will benefit, PGE notes that its 150 AMW action plan benefits the Company. And presumably PGE benefits in ways beyond simply earning a return on its investment base; for example, PGE may benefit from goodwill earned by acquiring renewable resources despite the lack of need or cost-effectiveness.

As a means to analyze whether the 150 AMW Action Plan results in benefits to ratepayers, AWEC recommends that the PGE IRP Portfolio and resource analysis be expanded to include the REC Bank as a means to comply with RPS, thereby deferring the need to acquire renewable resources to meet RPS requirements. This can be done directly in the ROSE-E optimization modelling. The relevant constraints are the annual RPS requirements and REC Bank. The annual level of REC bank is comprised of RECs newly generated as well as historic RECs comprised of infinite life-time RECs, five-year life-time RECs, and the 20% constraint on use of unbundled RECs. The modelling would include the option of selling Banked RECs with prices varying depending on the type of REC and whether it was contemporaneously generated or is from the previously banked RECs. The REC Bank would change each year depending on how many new RECs were added to the Bank, how many were sold, and how many RECs were retired in meeting the RPS requirement. The analysis could also include purchasing unbundled RECs as needed and using those RECs to partially meet the RPS requirement. Given that unbundled RECs can meet 20 percent of any year's revenue requirement, taking full advantage of that option over five years would represent a one-year deferral in the need to acquire renewable resources to meet RPS requirements.[2/]

Given that PGE has identified a risk that RPS generation could be different (lower) than expected, the RPS requirement could be expressed as being met by the REC Bank that reflects a de-rated level of current and future level of renewable generation, for example 90% of expected future renewable generation.

The RPS requirement could then be expressed as an annual constraint that is met through in-year renewable generation as well as the REC Bank. There is no need to exogenously analyze REC-bank alternatives, but rather analyze endogenously through optimization. This recommended AWEC approach would rigorously analyze the options of: (a) buying and selling RECs to reduce total costs; and, (b) retiring RECs from the REC Bank to meet RPS requirements and thereby defer additions of renewable resources and reduce total costs.

The second option noted above of using the REC bank to defer the acquisition of additional renewable resources provides benefits to customers of avoiding needless rate increases. It appears that PGE has chosen a lower bound in analyzing this benefit by assuming that technological progress in wind generation is one percent per year measured in constant dollars.

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[2/] 100% = 20% * 5. Buying unbundled RECs promotes renewable resource development as it adds value to renewable resources developed elsewhere thereby lowering its cost.

This can be seen from Figure 2.5-1 on Page 10 of the HDR Project on Renewables and Battery Supply Side Options. A change from $1400/kW in 2028 to $1200/kW in 2043 represents an annual one percent reduction in 2018 dollars cost per kW.

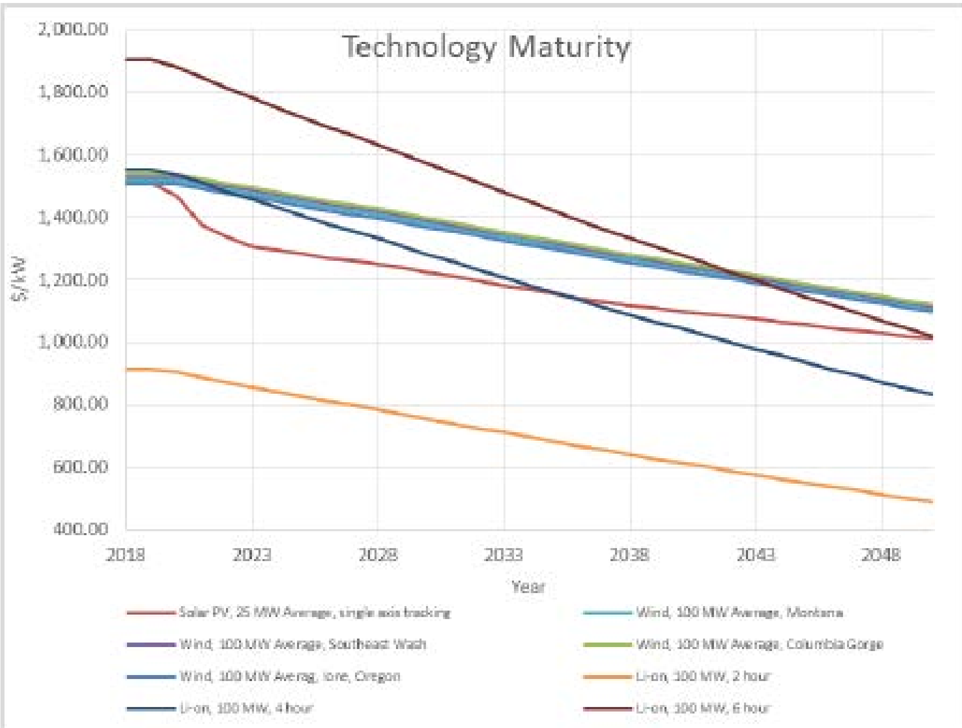


**Figure 2.5-1. Technology Maturity Model**

This cost reduction trend used by PGE can be more explicitly seen on page one of Appendix A-Technology Maturity/Cost Forecast. A portion of that table is presented below.

2018 US $/kW, FNTP Year

| Technology | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 |
|---|---|---|---|---|---|---|---|---|
| Solar PV, 25 MW Average, single axis | 1,510 | 1,510 | 1,469 | 1,374 | 1,335 | 1,307 | 1,294 | 1,282 |
| Wind, 100 MW Averag, Ione, Oregon | 1,508 | 1,508 | 1,508 | 1,493 | 1,478 | 1,464 | 1,449 | 1,436 |
| Wind, 100 MW Average, Columbia Gorge | 1,539 | 1,539 | 1,539 | 1,523 | 1,508 | 1,494 | 1,479 | 1,465 |
| Wind, 100 MW Average, Southeast Wash | 1,531 | 1,531 | 1,531 | 1,515 | 1,500 | 1,487 | 1,472 | 1,457 |
| Wind, 100 MW Average, Montana | 1,520 | 1,520 | 1,520 | 1,504 | 1,490 | 1,476 | 1,461 | 1,447 |
| Li-on, 100 MW, 2 hour | 915 | 915 | 905 | 889 | 873 | 858 | 842 | 827 |
| Li-on, 100 MW, 4 hour | 1,554 | 1,554 | 1,537 | 1,509 | 1,482 | 1,457 | 1,430 | 1,405 |
| Li-on, 100 MW, 6 hour | 1,902 | 1,902 | 1,881 | 1,847 | 1,814 | 1,783 | 1,750 | 1,719 |

For example, the ratio of $/kW expressed in 2018 dollars for 100 MW Columbia Gorge wind for the years 2021 to 2020 is 0.989 and rounds to 99 percent, or a reduction of one percent rate per year in the constant dollar installed cost of wind expressed in $/kW .

PGE's assumption of a one percent decrease in the constant dollar installed cost of wind resources understates technological progress. Other sources reporting on wind economics, such as the 2018 USDOE Wind Technologies Report, provides data that shows technological progress to be much greater than 1 percent per year.[3/] And while installed cost per kW is meaningful, the ability to capture greater energy at the same or lower wind speeds also affects the technological progress. Therefore, in addition to considering changes in installed cost over time, expected MWH generation also needs to be analyzed to capture improvements in turbine design.

PGE's understatement of the level of technological progress in wind generation economics is important when considering the REC Bank. If the REC Bank is used to defer the addition of wind projects, ratepayers benefit by allowing better technology wind projects to be built. This means lower cost per MWH of wind energy supplied. Another way of describing this impact is to say that with the same amount of money, in current dollars, society can buy more MW in wind if the wind project online date is delayed to capture technological progress. The PGE IRP analysis understates this benefit by using a one percent per year rate of technological progress.

**Question Topic Two: Are PGE customers currently receiving fair value for the REC Bank?**

To answer this question, the first step is to identify current OPUC policy and practice regarding RECs and associated ratemaking treatment. In various orders, the OPUC has considered the sale of RECs. Idaho Power is one of the OPUC-regulated utilities that has sold RECs. The OPUC issued Orders 10-392 and 11-086 regarding these activities. Order 11-086 provides some policy guidance. First, RECs are treated as property and that is why the Idaho Power filing is docketed by the OPUC as a UP filing. Second, the revenues from the sales are passed through to customers with the proviso that 10 percent of the revenues are retained by Idaho Power as an incentive to obtain the best price for the RECs. The Staff Public Meeting Memo dated February

[3/] Page x of the Executive Summary reports wind turbine installed costs of $2470/kW in 2010 to $1470/kW in 2018, both expressed in 2018 constant dollars. This reflects a technological progress of roughly six percent per year.

28, 2011, makes it clear that Idaho Power viewed RECs as a power cost component while Staff viewed RECs as utility property. The memo also discusses Idaho Power's view that the sale of RECs should be included with all other factors subject to the deadband. Thus, the revenues from the RECs could be within the deadband and retained in full by the Company as one potential outcome. The OPUC adopted Staff's recommendation that the RECs should be treated as property and flowed through to customers albeit with the 10 percent incentive feature.

Another docket relating to the sale of RECs is Order 11-512 for Docket UP 266. Again, one fact to note is that the docket is classified as a UP docket. In that Order, the Commission declined to direct PacifiCorp to sell its Oregon-eligible RECs. The Order resolved that,

> *Most importantly, the company concedes in the application that it believes the risk of selling RPS-eligible RECs is likely to outweigh the benefits. No competent evidence contradicts that assertion. Consequently, the application fails to meet the no-harm standard.*

Again, this order treats RECs as utility property and the long-standing practice of utility property sales is to allocate 100 percent of the gain to customers notwithstanding the OPUC order relating to Idaho Power.

PGE has discussed in this IRP, and in the 2016 IRP, providing value to ratepayers. In this current IRP, the context of PGE's offer to provide value to ratepayers is that PGE is proposing to acquire renewable resources ahead of need. And AWEC views PGE's offer to sell RECs as a recognition that rates charged to ratepayers will be higher than necessary to meet loads and statutory requirements. Therefore, PGE proposes to offset that rate impact by flowing back to ratepayers the revenues from the sale of RECs from these newly acquired resources. Page 34 of the 2019 IRP and Page 113 of the 2019 PGE IRP state that the value of the Wheatridge Energy Facility RECs generated prior to 2025 would be **returned** to ratepayers. It is interesting to note that PGE uses in its response the word "returned." That would imply that PGE agrees that the value of the RECs, and thus the REC Bank, is ratepayers'. As noted in the discussion on Question Topic 1, the REC Bank can be used to defer the need to acquire renewable resources due to RPS requirements. Whether RECs should be sold or retired could be answered in the ROSE-E optimization model or some other analytical method. Therefore, while AWEC appreciates PGE's recognition of the need to reduce costs, AWEC has not seen an analysis yet that optimizes the use of the REC Bank for the benefit of ratepayers—that is, deferring resources or selling RECs based on a robust economic analysis of both options.

Even if it is shown that selling RECs is one conclusion of that analysis, it should be clear that the proposal to sell RECs from newly acquired resources is unlikely to hold ratepayers harmless from the standpoint of rate impacts. With the acquisition of renewable resources in the near term, rates will increase. PGE's own analysis confirms this.[4/] If the cost per kW of installed capacity is $1500[5/], the before-tax cost of capital is 9.27%[6/], capacity factor of the wind site is 40 percent[7/], and the wind resource is eligible for a PTC of even 2.5 cents per kWh, then assuming a 25-year plant life, the first year revenue requirement could be as high as $42 million[8/], not including any power cost savings. This compares to REC sales revenues of $2 million[9/], assuming a REC sales price of roughly $1.50/MWH. While it is true that the addition of low variable cost renewable resources would save variable energy costs, the first-year energy cost savings in order to hold customers harmless would need to be $40,000,000.[10/] This also ignores ratepayers losing technological progress cost savings. If technological progress savings are even two percent per year in nominal terms, the lost cost savings is over $800,000 per year.[11/]

What does not appear to have been discussed to date before the OPUC is what ratemaking treatment should be provided to customers for the RECs PGE holds until they are sold or retired? Before diving into the discussion, a couple of contextual comments are needed. AWEC understands that the OPUC will open a docket to consider the manner by which value would be returned to customers. Second, AWEC knows that the IRP is not a ratemaking docket. Thus, this discussion is just to broach for the Commission and interested parties what might be a position AWEC would espouse in that docket or PGE's next general rate case, whichever occurs first.

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[4/] IRP at 199, Figure 7-16.
[5/] Appendix A Technology Maturity, page 1
[6/] Table I-1, page 341 of 678
[7/] Page 135 of 678. AWEC notes that none of PGE's wind resources currently operate at a 40 percent capacity factor and so PGE is likely optimistic about the new wind resource operating capability and thereby underestimating its per MWH cost as the capital cost of the wind project would actually be spread over fewer MWHs.
[8/] $42 million = (150 AMW/0.4)*$1500/kW*1000 kW/MW*0.097+((150 AMW/0.4)*$1500/kW*1000 kW/MW)/25
[9/] $2 million = 150 AMW*8760*$1.50
[10/] $40,000,000 = $42,000,000 - $2,000,000
[11/] $0.835 million = $42,000,000*0.02

The REC Bank is property to the benefit of ratepayers. This position is supported by the fact that RECs are generated by renewable energy production. The RECs have been paid by ratepayers either through purchased power rate mechanisms, if the RECs were procured through a purchased power agreement and the costs of the power purchase was included in the variable power cost; or, ratepayers have paid for the RECs as the PGE-owned renewable resources are included in rate base. In the rate base context, as RECs are generated through power production each year, so too are the renewable resource rate base revenue requirements through rate of return and depreciation. Therefore, the RECs are ratepayer property held and managed by the utility.

The REC Bank has market value and this market value is material. If the REC Bank equaled 1200 AMW, and the average value of those RECs was $1.00, the rate base value of the REC Bank is over $10 million.[12/] Just like any asset "sitting" in inventory, the REC Bank has market value. One could envision two valuations. The first valuation is a Regulatory Valuation ("RV") which is to have each vintage and type of REC valued at the then market price when the REC was produced. This is an historic-vintaging approach consistent with typical economic regulation of utilities. The second valuation is a market valuation ("MV") where the REC Bank is valued at current market prices. This can be thought of as a mark-to-market valuation.

Under the RV scenario, ratemaking for the REC Bank would be as follows. First, the RV would be included in revenue requirements as an offset to the utility's rate base. There is a rate base offset because the RV is the result of utility activities recoverable and includable in rates charged to ratepayers.[13/] This is akin to other rate base offsets where customers have been charged in rates but not yet received the value of the resource, such as deferred tax credits or business energy tax credits. Similarly, PGE also includes assets in rate base on which customers *pay* a return. For instance, PGE provides the value of PTCs to customers in the year they are generated through its annual power cost filings. Because PGE lacks the taxable income to use all of these

12/ $10,000,000 = 1200 AMW*8760 hours*$1/MWH.

13/ The utility activities are the ones discussed above. Purchasing renewable power and including those costs in power costs as well as PGE-owned renewable resources where rates include the renewable resource rate base as well as any associated power costs.

PTCs in that year, however, they are deferred and held in rate base as a deferred tax asset. PGE has argued in the past that this is appropriate because it is providing customers with the value of the PTC up front, and receiving the benefits at a later date (when its tax liability allows for use of the deferred PTCs). Similarly here, customers pay for the RECs as they are generated (through payment of depreciation expenses and a return on PGE's investment in RPS resources), but the value of any RECs that are banked is deferred to a later date (indeed, deferred forever under PGE's IRP – the REC Bank is never used).

The REC Bank Offset would change each year depending in part on the RV of RECs that have been added to the bank as well as the RV of RECs purchased, sold or retired. In addition, depreciation could occur for those RECs that have finite lives such as the newly produced RECs that legislatively have a five-year life. An argument for depreciation is that as each year passes for such a REC, the number of years that the REC could be used for RPS obligations is reduced. On the other hand, an argument for not depreciating the five-year RECs is that at any time during the five-year REC term, the amount that the REC meets the RPS obligation, i.e., 1 MWH, does not diminish or decrease.

Each year, customers would also receive monies from the sale of RECs, to the extent they are sold. Presumably, these monies could go into the utility's property sales balancing account which is flowed through to customers each year.

In one context of the PGE discussion of the REC Bank, there are a few analogies in current ratemaking that support the idea that the REC Bank should be an offset to rate base. In the 2016 IRP, PGE identified up to 260 AMW of RECs to be held as a risk mitigation measure to take into account, for example, unexpected low MWH production from renewable resources. This means that a "stockpile" of RECs would be held in reserve. Two analogies come to mind in this circumstance. One is the coal stockpile that was held at Boardman as a precaution should an interruption occur in rail delivery.[14/] The stockpile of coal is included in rate base. A second example is "cushion" gas held at Mist.[15/] The Mist natural gas storage site maintains a minimum

[14/] See Order 16-419, pages 4-5.
[15/] See Order 13-349, pages 3 and 5.

level of natural gas to maintain efficient operations. This cushion gas is also treated as a rate base asset. A portion of the REC Bank is clearly comparable to these two examples. And so, at a minimum, the REC Bank held to mitigate operational risk of renewable generation should also be treated as a rate base asset for the benefit of customers. In the REC Bank example, it is a rate base offset as the RECs are customer property, as evidenced by the fact that in a REC sale, revenues are credited to customers.

**Bradley Mullins**
Energy & Utility
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October 11, 2019

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

Re: LC 73 - Comments on behalf of AWEC on the 2019 Integrated Resource Plan of Portland General Electric Company

Dear Commissioners:

I appreciate the opportunity to provide comments on behalf of the Alliance of Western Energy Consumers ("AWEC") on the 2019 Integrated Resource Plan ("IRP") of Portland General Electric Company ("PGE"). AWEC is a non-profit trade association representing large utility customers located throughout the Northwest, including customers of PGE. Accordingly, AWEC is interested in having PGE plan its system on a least-cost, least-risk basis.

In summary, AWEC appreciates PGE's dedication to sustainability and reliability, as well as the thorough detail and analysis presented in PGE's 2019 IRP. Notwithstanding, AWEC has several concerns and recommendations for the Commission to consider with respect to PGE's action plan and its resource needs assessment. Specifically, AWEC recommends the Commission require PGE to:

1. Make an adjustment to remove new load direct access customers from PGE's industrial load forecast;

2. Consider the capacity and Renewable Portfolio Standard ("RPS") attributes associated with the voluntary Green Tariff program in its resource needs assessment;

3. Adopt more realistic assumptions for market import capability from both the Mid-Columbia ("Mid-C") and California-Oregon-Border ("COB") market hubs in its resource needs assessment;

4. Consider the resource adequacy benefits of participating in an organized day-ahead market, such as the Extended Day-Ahead Market; and

5. Adopt a more flexible procurement strategy for securing bilateral contracts, including near-term contracting opportunities.

I discuss each of these recommendations in the sections that follow. Further, Appendix A details the cumulative impact of these adjustments on PGE's load and resource balance. It shows that PGE is in a capacity surplus position until 2030, after considering the issues identified above.

## 1. Direct Access Assessment

In comments on PGE's 2016 IRP, I performed a portfolio analysis that showed cost-of-service customers would save approximately $433.5 million on a 20-year net present value basis if PGE assumed that an additional 150 MW of load participated in its long-term direct access program.[1/] This savings is due to PGE being able to avoid incremental capacity additions to meet this load, which would impose additional costs on cost-of-service customers. My analysis reflected the same finding as a Puget Sound Energy analysis developed to determine the impact of Microsoft Corp. buying electricity from a third party.[2/] So long as a utility has a capacity deficit, reducing load is a lower-cost, lower-risk strategy than acquiring capacity resources. Given the strong load growth and future need for resources that PGE identifies in this 2019 IRP, the potential for cost savings for cost-of-service customers from PGE assuming additional load elects direct access remains.

Notwithstanding, PGE's IRP takes the opposite approach – an approach that would be higher cost and higher risk for its customers if implemented. PGE states that it has excluded long-term direct access ("LTDA") customer loads and new load direct access ("NLDA") customer loads from all aspects of its needs assessment.[3/] Notwithstanding, the industrial load forecast contains no recognition of future NLDA customer loads, despite the creation of this new program. This practice is flawed and will lead to over-building PGE's system at the expense of cost of service customers.

The lack of consideration for the NLDA program can be noted on Page 256, where PGE discusses its industrial load forecast. PGE's IRP assumes industrial load growth of approximately 150 aMW over the period 2020 through 2025.[4/] It can be noted that PGE uses US Gross Domestic Product as the sole variable for its industrial forecast, and makes no downward adjustment for the NLDA program.

It would be contrary to the purpose of the NLDA program if PGE were to acquire new resources to serve customers that will participate in that program. Accordingly, I recommend PGE make an explicit assumption regarding the large customers that will opt-out of cost of service rates in the IRP study period. This assumption would exclude all NLDA customers from the load forecast, up to the program cap.

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1/ LC 66, Initial Comments of Bradley G. Mullins at 11 (Jan. 24, 2017).
2/ WUTC Docket UE-161123, Exh. No.__(JAP-1T) (Oct. 7, 2016).
3/ 2019 IRP § 4.7.3.
4/ 2019 IRP at 255.

PGE calculated the capacity necessary to serve the NLDA program as 153 MW.[5/] Accordingly, removing the NLDA capacity has a material impact on PGE's overall capacity needs, representing 27.7% of PGE's 595 MW stated dispatchable resource need in 2025. As detailed in Appendix A, applying this and a few other adjustments to PGE's load and resource balance has the effect of eliminating any capacity need in 2025.

Further, I disagree with the nature of the direct access sensitivity studies PGE discusses in section 4.7.3. PGE assumes that all direct access customers in its balancing area were compelled to resume service as cost of service customers. I believe this to be an unlikely, if not impossible, scenario. Further, I disagree with the narrative that direct access customers place a resource adequacy burden on PGE. I am aware of no customer that has opted out and subsequently returned to cost of service rates, and there are protections in place to avoid undue cost-shifting if such a circumstance did arise.

Notwithstanding, it is important for PGE to study the benefits, both in terms of costs and risks, of incremental direct access participation on its capacity expansion plan. PGE's analysis shows the incremental impact of serving direct access customers on its loss of load expectation, but it does not detail the capacity costs that are saved as a result of the direct access customer participation. Such an analysis would be useful for evaluating the capacity costs that are avoided as a result of the program participation and how the capacity cost savings impacts non-participating customers. Recall that in PGE's most recent rate case, parties questioned whether capacity costs savings were appropriately considered as a component of the transition adjustment calculation, and the Commission itself recognized the need to consider this savings, at least if PGE were allowed to extend transition adjustments to 10 years.[6/]

Serving the additional 526 MW of direct access customer load detailed in table 4-15 would be a significant cost. Relative to the $1,902/kW capacity cost of a 6-hour lithium battery, the savings associated with avoiding this capacity to serve the direct access program is approximately $100,000,000. On a levelized basis, this level of investment represents about $130.00/kW-yr[7/], which compares unfavorably to the $106.42/kw-yr of marginal capacity costs embedded in rates. Thus, the direct access program provides material cost savings to non-participating customers.

## 2. Green Tariff Program Capacity

In Section 2.1.3 of the 2019 IRP, PGE discusses its Voluntary Green Energy Programs, including PGE's green tariff, the "Green Energy Affinity Rider."[8/] While noting the material benefits of the programs, PGE states that "[b]ecause these programs have not yet started or are relatively new, the 2019 IRP does not explicitly incorporate forecasts of customer participation

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5/ 2019 IRP at 125, Table 4-15.
6/ Docket UE 335, Order No. 19-129 at 19-20 (Apr. 12, 2019).
7/ Using a capitalization factor of 7%.
8/ See Docket UM 1953.

in these programs within its core portfolio analysis." That is, PGE does not consider any of the capacity or RPS impacts of the resources it is planning to acquire for these programs.

I disagree with this approach. I recommend PGE consider the capacity and RPS impacts of its Voluntary Green Energy Programs, including the green tariff, in its IRP portfolio analysis.

PGE's green tariff program, which has a cap of 100 MW, has been a popular program. Enrollment in the program began at 1:00 p.m. on May 31, 2019. In its September 13, 2019 compliance filing in Docket No. UM 1953, PGE notes that "customers filled the subscription window for the 100 MW […] in under two minutes."

It is important for the capacity and RPS impacts of the green tariff program to be considered in order to avoid cost-shifting to non-participating customers, through overbuilding the system. The rates for these programs were designed with an objective of ensuring that the new capacity would not increase the rates applicable to non-participating customers. The programs could, however, reduce the costs applicable to non-participating customers. If PGE continues to build for the participating customers, as if the green tariff program did not exist, that will increase the costs and result in a cost shift. PGE will be executing power purchase agreements for 100 MW of renewable capacity as a result of the program participation and the capacity and energy from the green tariff PPA is appropriately considered in the IRP.

Further, PGE states that it does not include any of the RPS impacts of the green tariff program in its IRP. Since the green tariff customers are acquiring their own renewable capacity for 100% of their load, there is no need to acquire additional RPS resources to meet the loads served by the green tariff. PGE's analysis, on the other hand, assumes it must acquire RPS resources for the green tariff customer loads.

### 3. Market Import Capability

Similar to past IRPs, PGE's 2019 IRP assumes virtually no market import capability when performing its resource needs assessment.

On page 288 of the 2019 IRP, PGE details that its resource needs assessment considers only 91 MW of market import capability in 2021, an amount that declined to only 10 MW in 2030. Further review of the RECAP files that PGE provided in response to AWEC Data Request 03 shows that the Loss of Load Expectation modeling PGE performed included zero peak load market capability.

Notwithstanding, PGE possesses significant import capability from both the Mid-Columbia and California-Oregon Border ("COB") market hubs.

From Mid-C, PGE previously assumed that it has approximately 200 MW of import capability. In addition, PGE maintains significant transmission rights from the COB market hub. Given regionalization, these import rights from the COB market are becoming increasingly valuable.

Further, based on PGE's 2019 Transmission Transfer Capability published on OASIS, PGE's system can import approximately 727 MW South-to-North from the COB market. My understanding is that the entire amount of this import capability may be used for PGE's load service. After considering PGE's right from Mid-C, PGE has at least 900 MW of import capability, yet PGE's IRP includes virtually none of this capability when designing its capacity expansion plan.

The value of these import rights was demonstrated in connection with the Enbridge incident. In response to that incident, PGE was able to back down its gas generators and import power from COB in order to maintain the reliability of the region.

Accordingly, I view PGE's assumptions of virtually no market import capability to be unrealistic. Customers pay for the cost of PGE's transmission system, and the import capability that is associated with that transmission capability is appropriately reflected in PGE's capacity expansion plan.

In Appendix A, I have included only 100 MW of import capability from the COB market. Viewed in conjunction with other adjustments, that amount of import capability was sufficient to avoid capacity deficiency through 2030.

### 4. Extended Day-Ahead Market

Market import capability is of particular importance in the context of regional markets. The rules that define and assign market import capability to the various load serving entities have a direct impact on the capacity that participants must acquire to serve loads. Rather than having each utility make disparate assumptions about the market import capability available, an organized market would provide greater certainty surrounding the market import capability available to each participant. Each participant would be assigned a particular amount of import capability based on a formula established by the market. An organized market will typically establish a resource adequacy credit based on load diversity to account for the ability of participants to import and export capacity between participants.

As PGE looks to fill its future capacity needs, particularly in light of the fact that PGE includes very little market capability in its expansion plan, I recommend that PGE closely study the capacity effects of participating in a regionalized Extended Day-Ahead Market, or similar market structure. If such a market structure would provide PGE with more resource adequacy in connection with its existing import rights than PGE is currently assuming, PGE will be able to delay acquisition of some of the resources identified in the 2024 and 2025 timeframe. Given the cost of the resources identified in 2024 and 2025, I recommend PGE investigate the potential for resource adequacy benefits of participating in an organized market before building any new resources.

**5. Existing Regional Capacity**

In Action 3, PGE discusses its plan for acquiring new capacity resources. PGE notes that, prior to constructing new physical capacity resources, PGE intends to consider bilateral contracts for existing regional capacity.

AWEC supports PGE evaluating bilateral contracts with existing regional capacity for purposes of satisfying its future capacity needs, particularly before investing in the construction of new regional resources. Recent experience with similar resource procurement activities for regional capacity has been positive.

PGE's resource needs in 2024 and 2025 are being driven predominantly by the expiration of existing bilateral agreements. Much of the resource need that PGE identified in the 2024 to 2025 timeframe is being driven by expiring contracts with the Bonneville Power Administration ("BPA"), Avangrid Renewables, and Pelton Round Butte (Tribes). The expiration of these agreements will result in a loss of approximately 449 MW of capacity to PGE. Accordingly, AWEC supports PGE's staged process approach that considers new bilateral contracting alternatives, before conducting an RFP for capacity resources.[9/]

I recommend, however, that PGE adopt a flexible approach to its bilateral contracting activities, specifically considering contracting opportunities beginning in 2024 and contracts with a range of terms of as short as 3 years. There are several reasons for adopting a flexible procurement strategy.

BPA is a good candidate for bilateral contracting opportunities. BPA is in a firm surplus position and may be in a position to provide highly flexible, carbon-free capacity to PGE. In the final rate models published in the BP-20 rate proceeding, for example, BPA had 212 aMW and 154 aMW of Firm Surplus capacity available for Fiscal Years 2020 and 2021.

If PGE were to limit its procurement to contracts with terms exceeding five years, however, that might limit PGE's ability contract with BPA. The Regional Dialogue contracts between BPA and BPA's customers currently extend through September 30, 2028. Accordingly, from a practical perspective, BPA may find it difficult to make long-term commitments beyond September 30, 2028, due to uncertainty surrounding the renewal of the Regional Dialogue contracts.

In Appendix A, I have considered the capacity benefits of extending contracts with BPA, Avangrid Renewables, and Pelton Round Butte (Tribes). The analysis shows that if these agreements are extended, PGE will be in a surplus position. Accordingly, I believe it is

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9/ 2019 IRP at 218-19.

appropriate for PGE to place emphasis on extending existing contracts, or potentially entering into new arrangements, before building new capacity resources.

**Conclusion**

In Appendix A, I have taken the load and resource balance PGE provided in Appendix G on page 288 of the IRP. I added in expected procurements of energy efficiency and demand response from PGE's action plan. I also added in amounts for each of the adjustments I discussed above. As can be seen, it shows that PGE is in a resource sufficiency position through 2030 after the adjustments are considered. The 2030 sufficiency position in Appendix A, therefore, demonstrates several things, including 1) the benefits of the NLDA program on avoiding new resource additions; 2) the need to study import capability, particularly in the context of a regional organized market; and, 3) the importance of existing bilateral agreements on PGE's overall load and resource balance.

I appreciate this opportunity to provide these comments and respectfully request the Commission consider my recommendations. AWEC looks forward to working with PGE as it implements the 2019 IRP.

Sincerely,

*/s/ Bradley Mullins*

Bradley Mullins

Appendix A
PGE Capacity Needs after Adjustments
LC-73 - Comments of Bradley Mullins

| | 2021 | 2022 | 2023 | 2024 | 2025 | 2030 | 2035 | 2040 | 2045 | 2050 |
|---|---|---|---|---|---|---|---|---|---|---|
| Gas | 1,833 | 1,833 | 1,833 | 1,833 | 1,833 | 1,833 | 1,833 | 1,833 | 1,833 | 1,833 |
| Coal | 296 | 296 | 296 | 296 | 296 | 296 | - | - | - | - |
| Hydro | 786 | 784 | 784 | 780 | 547 | 472 | 472 | 472 | 472 | 472 |
| Wind+Solar | 293 | 342 | 347 | 368 | 350 | 360 | 294 | 191 | 160 | 160 |
| Add: Green Tariff Cap. | 24 | 24 | 24 | 24 | 24 | 24 | 24 | 24 | 24 | 24 |
| Other Contracts | 344 | 344 | 344 | 278 | 244 | 44 | 25 | - | - | - |
| Add: Contract Extnsns. | | | | | | | | | | |
| Avant Grid | | | | 100 | 100 | 100 | 100 | 100 | 100 | 100 |
| Bonneville | | | | | | 200 | 200 | 200 | 200 | 200 |
| Pelton Round Butte | | | | | 149 | 149 | 149 | 149 | 149 | 149 |
| Storage | 15 | 15 | 13 | 12 | 12 | 12 | - | - | - | - |
| DER | 70 | 77 | 84 | 96 | 96 | 133 | 180 | 227 | 296 | 362 |
| DSG | 107 | 106 | 108 | 109 | 109 | 113 | 119 | 124 | 128 | 132 |
| Market Capacity | 91 | 58 | 37 | 26 | 19 | 10 | 8 | 6 | 8 | 9 |
| Add: COB Market Cap. | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 |
| Total Resources | 3,959 | 3,879 | 3,870 | 3,922 | 3,779 | 3,746 | 3,404 | 3,326 | 3,370 | 3,441 |
| Load | 3,456 | 3,485 | 3,524 | 3,560 | 3,600 | 3,824 | 4,072 | 4,342 | 4,640 | 4,919 |
| Less: EE | (106) | (107) | (108) | (133) | (157) | (167) | (178) | (189) | (202) | (215) |
| Less: Demand Resp. | | | (267) | (276) | (282) | (282) | (282) | (282) | (282) | (282) |
| Less: NLDA | (153) | (153) | (153) | (153) | (153) | (153) | (153) | (153) | (153) | (153) |
| Net Load | 3,197 | 3,225 | 2,996 | 2,998 | 3,008 | 3,222 | 3,459 | 3,718 | 4,003 | 4,269 |
| TRM% | 16% | 16% | 16% | 17% | 16% | 16% | 15% | 15% | 14% | 14% |
| Total Reserve Margin | 512 | 516 | 479 | 510 | 481 | 516 | 519 | 558 | 560 | 598 |
| Load+Reserves | 3,709 | 3,741 | 3,475 | 3,508 | 3,489 | 3,738 | 3,978 | 4,275 | 4,563 | 4,867 |
| Capacity Def./ (Surpl.) | (250) | (138) | (395) | (414) | (290) | (8) | 574 | 949 | 1,193 | 1,426 |

August 13, 2019

TO: Rose Anderson
Public Utility Commission of Oregon

FROM: Jay Tinker
Director, Rates and Regulatory Affairs

**PORTLAND GENERAL ELECTRIC**
**LC 73**
**PGE Response to OPUC Data Request No. 022**
**Dated July 30, 2019**

**Request:**

**See Sections 4.5 RPS Need and 7.1.1.2 RPS Requirements. PGE requires all portfolios between 2027 and 2050 across all futures to meet physical RPS compliance; however, the Company forecasts that 1) without incremental renewable resource actions, RPS obligations will exceed generation from RPS-eligible resources in the Reference Case beginning in 2030; and 2) a strategy of compliance through REC bank depletion could meet RPS obligations through 2035 in the Reference Case. Please explain:**

a. **Whether the REC bank depletion strategy also includes using unbundled RECs to meet 20% of PGE's RPS compliance?**
b. **How the Company identified the year 2027 to begin requiring physical compliance across all futures?**
c. **How many banked and newly acquired RECs the Company would use per year under the "REC bank depletion" strategy referenced in Section 4.5 RPS Need?**
d. **Under the reference case, how many banked RECs will the Company have in 2027? Please specify how many of these RECs are 5 year and how many are infinite life RECs.**
e. **Under the reference case, what is the minimum number of banked RECs the Company needs to "mitigate compliance risks" as mentioned in Section 4.5 RPS Need?**

*Response:*

PGE objects to this request on the grounds that it requests speculation and new analysis. Without waiving these objections, PGE responds as follows.

a. The strategy of RPS compliance through REC bank depletion discussed in Section 4.5 of the 2019 IRP does not assume the future acquisition of unbundled RECs. It does assume the use of all banked RECs as of the bank snapshot date, including unbundled RECs.

b. The year 2027 was chosen as the beginning of the physical RPS compliance requirement because it is the earliest year outside of the action plan window (2023-2025) in which renewable resource additions are allowed. During the action plan window, the constraint was not applied because resource additions are the same across futures during this period, imposing the physical compliance constraint would require all portfolios to achieve the physical RPS compliance of the High Need Future in these years.

c. PGE did not differentiate between banked and contemporaneously generated RECs in forecasting REC retirements for the REC bank depletion strategy described in Section 4.5. Attachment 022-A provides the banked and contemporaneously-generated RECs that would be retired in each year in the Reference Case if PGE were to pursue no additional renewable resources and were to retire RECs in the following manner in each year: first, retire 5-year RECs in the bank in order of vintage (earliest first); next, retire contemporaneously-generated RECs; and finally, retire infinite-life banked RECs if they are needed. This analysis is provided for informational purposes only, reflects only one potential strategy for future REC retirement, and does not necessarily forecast actual future REC retirements.

d. Assuming no new resource additions, the forecasted number and type of RECs in the bank in 2027 depends on the REC retirement strategy. Given the assumptions discussed in the response to Part C, at the end of 2027, there would be 1600 MWa of RECs banked (1195 MWa of infinite-life RECs and 405 MWa of 5-year RECs).

e. PGE did not establish a minimum REC bank requirement in the 2019 IRP because constraints related to the REC bank were found to not be significant drivers of renewable resource economics in the near term. For additional context, under the "REC bank depletion" strategy referenced in Part C, the REC bank balance would not drop below the minimum REC bank constraint established in the 2016 IRP until 2035, approximately one year before the REC bank would be fully depleted under such a strategy.

As discussed in Section 4.5 of the 2019 IRP, a REC bank depletion strategy would significantly delay the benefits of bringing new renewable resources onto the system. Given the intent of SB 1547, the preferences expressed by many of our customers, and our own long-term decarbonization goals, PGE does not consider such a strategy to be in the interest of our customers, the state of Oregon, or our company.

August 19, 2019

TO: Jesse O. Gorsuch
Alliance of Western Energy Consumers'

FROM: Jay Tinker
Director, Rates and Regulatory Affairs

**PORTLAND GENERAL ELECTRIC**
**LC 73**
**PGE Response to AWEC Data Request No. 004**
**Dated August 6, 2019**

**Request:**

**Please identify the annual number of RECs projected from the Wheatridge Energy Facility from 2020 through 2025, inclusive.**

*Response:*

The forecast of annual REC production for 2020 through 2025 from the Wheatridge Renewable Energy Facility is provided in Attachment A. Attachment A is protected information subject to Protective Order No. 19-186.

As noted in Section 4.5 of the 2019 IRP, the value of RECs generated by the Wheatridge Energy Facility prior to 2025 will be returned to customers and as such, RECs generated by the Wheatridge Energy Facility prior to 2025 are not included in the IRP forecast of REC production from existing and contracted resources.

The forecast of REC production for 2020 is zero because Wheatridge is expected to enter service at the end of 2020.

Page 4 of Attachment C has been designated by PGE as Protected Information Subject to Protective Order No. 19-186 and has been redacted in its entirety.

September 4, 2019

TO: Jesse O. Gorsuch
Alliance of Western Energy Consumers’

FROM: Jay Tinker
Director, Rates and Regulatory Affairs

**PORTLAND GENERAL ELECTRIC**
**LC 73**
**PGE Response to AWEC Data Request No. 006**
**Dated August 21, 2019**

**Request:**

**Please provide the value of the RECs generated from the Wheatridge project in each year from 2021 through 2024 that PGE will return to customers.**

*Response:*

PGE objects to this request to the extent that it requests new analysis and seeks speculation. Without waiving these objections, PGE responds as follows:

PGE has not performed the analysis requested.

OPUC Order No. 18-044 states that “Staff may request that we [the Commission] open a docket on mechanisms for delivering value from incremental RECs to customers in a public meeting at a later date.”[1] PGE anticipates requesting authority from the Commission to sell Wheatridge RECs on behalf of cost-of-service supply customers. PGE looks forward to further discussion in the appropriate docket, which we anticipate would be the Renewable Adjustment Clause ratemaking proceeding for Wheatridge.

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[1] OPUC Order No. 18-044 at 2.