ORDER NO. 21-482

ENTERED Dec 22 2021

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UI 461

In the Matter of PORTLAND GENERAL ELECTRIC COMPANY, Application for Approval of an Affiliated Interest Transaction with Portland Renewable Resource Company.	ORDER

DISPOSITION: STAFF'S RECOMMENDATION ADOPTED

At its public meeting on December 14, 2021, the Public Utility Commission of Oregon adopted Staff's alternative recommendation to reject Portland General Electric Company's application. The Staff Report with the recommendation is attached as Appendix A.

BY THE COMMISSION:

Nolan Moser
Chief Administrative Law Judge

A party may request rehearing or reconsideration of this order under ORS 756.561. A request for rehearing or reconsideration must be filed with the Commission within 60 days of the date of service of this order. The request must comply with the requirements in OAR 860-001-0720. A copy of the request must also be served on each party to the proceedings as provided in OAR 860-001-0180(2). A party may appeal this order by filing a petition for review with the Circuit Court for Marion County in compliance with ORS 183.484.

ITEM NO. RA4

PUBLIC UTILITY COMMISSION OF OREGON
STAFF REPORT
PUBLIC MEETING DATE: December 14, 2021

REGULAR X **CONSENT** ____ **EFFECTIVE DATE** N/A

DATE: December 4, 2021

TO: Public Utility Commission

FROM: Curtis Dlouhy

THROUGH: Bryan Conway, John Crider, and Matt Muldoon **SIGNED**

SUBJECT: PORTLAND GENERAL ELECTRIC:
(Docket No. UI 461)
Requests approval for an Affiliated Interest Transaction between PGE and Portland Renewable Resource Company.

STAFF RECOMMENDATION:

The Public Utility Commission of Oregon (Commission) should approve Portland General Electric's (PGE or Company) Application for Approval of an Affiliate Interest (AI) Agreement with Portland Renewable Resource Company ("Application") to provide support services to the Portland Renewable Resource Company (PRR) in accordance with the Master Service Agreement (MSA) between PGE and its affiliates, subject to no less than the conditions contained in Attachment 1 to this memorandum.

OR

The Commission should reject PGE's Application.

DISCUSSION:

Issue

Whether the Commission should approve PGE's application for approval of an affiliate transaction with PRR to provide support services in accordance with the Master Service Agreement.

Applicable Law

ORS 757.495 requires a public utility to seek Commission approval of contracts involving the direct or indirect payment to any person or corporation having an affiliated interest within 90 days after execution of the contract. The required process for submitting an agreement for review by the Commission is set forth in ORS 757.495 and OAR 860-027-0040.

"Affiliated interest," as defined in ORS 757.015(3), includes "[e]very corporation five percent or more of whose voting securities are owned by any person or corporation owning five percent or more of the voting securities of such public utility or by any person or corporation in any chain of successive ownership of five percent or more of voting securities of such public utility."

ORS 757.495(3) provides that the Commission may approve an affiliated interest contract if it is "fair and reasonable and not contrary to the public interest." The "fair and reasonable and not contrary to the public interest" standard is customarily applied as a "no harm" standard by the Commission.[1]

OAR 860-027-0040(2) sets forth information to be included in an application to the Commission regarding an affiliate interest transaction.

OAR 860-027-0048(4)(b) provides that "when an asset is transferred from an energy utility to an affiliate, the transfer shall be recorded in the energy utility's accounts at the approved rate if an appropriate rate is on file with the Commission or with FERC. If no approved rate is applicable, proceeds from the transfer shall be recorded in the energy utility's accounts at the higher of net book value or fair market value."

The Commission need not determine the reasonableness of all financial aspects of the contract for ratemaking purposes, as the Commission reserves that issue for a subsequent proceeding, per Commission Order No. 11-071 in Docket No. UI 306.

Analysis

Background
PGE filed its Application pursuant to OAR 860-027-0040, OAR 860-027-0041, ORS 757.015, and ORS 757.495 on September 10, 2021, requesting approval for an affiliated interest transaction with PRR to provide PRR with support services in

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[1] *See e.g., In the Matter of Portland General Electric Co. Application for Approval to Sell its 2.5 Percent Ownership Share of the Centralia Steam Electric Generating to Avista Corporation* (UP 165), Order No. 00-152 (*Order on Reconsideration* March 12, 2000).

accordance with PGE's MSA.[2] PGE filed the signed copy of its updated MSA on October 25, 2021. The addendum including PRR in the MSA was signed on October 22, 2021.[3]

PRR is a wholly owned direct subsidiary of PGE and qualifies as an affiliate under ORS 757.015(6). PGE states that upon the request of its board of directors, officers, or managers, PGE will furnish administrative services including office support, business analysis, finance and treasury support, human resources, investor relations, legal service, construction and engineering services, purchasing, consulting and training services, and other services.[4] The Company states that these services will be provided to PRR at the higher of cost or market unless otherwise specified and approved by the Commission.[5]

PGE notes that the reason behind its overall proposal to establish PRR as a subsidiary is to address structural tax disadvantages encountered by utilities due to what PGE describes as unintended consequences of the Internal Revenue System's (IRS) rules around investment tax credit (ITC) normalization.[6] Whereas independent power producers (IPP) are allowed to realize the tax benefits from ITCs up front, regulated utilities are required by the IRS to normalize ITCs over the life of the asset. Due to the time-value of money, a regulated utility that submits a project would have a higher price than an identical project submitted by an IPP that is not subject to normalization. PGE characterizes this structural tax disadvantage experienced by utilities as a hindrance to House Bill (HB) 2021's goals to reduce carbon emissions because it lowers access to competitively priced renewable energy.[7] PGE characterizes the inefficiency of ITC normalization as adding an additional 20 percent to the levelized cost of energy for a project.[8]

To get around the ITC normalization requirements, PGE proposes to allow PRR to bid renewable energy projects into its RFPs.[9] PRR would then sell any power generated back to PGE through a Power Purchase Agreement (PPA) and keep capital investment from any projects associated with the PPA out of rate base. Through this PPA rate and removal of PRR assets from rate base, PGE claims that the resource would be viewed

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2 *Application* for Approval of an Affiliated Interest Transaction with Portland Renewable Resource Company ("Application"), p. 1.
3 *Addendum* 8 to Portland General Electric Company's (PGE) Master Service Agreement (MSA) between PGE and its affiliates, p. 26.
4 *Application*, Att. 1, p. 2.
5 *Application*, p. 9.
6 *Application*, p. 2.
7 *Application*, p. 3.
8 *Application*, p. 4.
9 *Application*, p. 8.

as non-public-utility-owned by the IRS and thus not be subject to the inefficiency caused by ITC normalization.[10]

PGE notes that it explored many other options to avoid ITC normalization, including advocating for Federal tax policy changes, setting up a holding company with an unregulated affiliate, and tax equity options.[11] The Company states that after consulting with subject matter experts in its tax department, other utilities, and outside consultants, it has determined that the proposed affiliate structure provides the best balance of competitive prices for customers, complexity and risk allocation.

PGE does not currently have an estimate for the amount it expects to receive from PRR as a result of its filing because the services PRR would receive from PGE are contingent upon future activities.[12] The Company also states that it does not expect PRR to have its own employees.[13]

The Company notes that any PPA procured through a competitive bidding process will be subject to approval through a subsequent affiliated interest filing.[14] PGE also intends to seek approval of a parental guaranty on behalf of PRR with a subsequent affiliated interest filing.[15] This parental guaranty would allow PRR to secure loans with PGE responsible for payment in the event that PRR is unable to pay.

Staff held three workshops with the Company and intervenors on October 14, 2021, November 1, 2021, and December 4, 2021. In these workshops, PGE discussed its filing in greater detail and noted that it intends to have PRR to bid in PGE's upcoming RFP in January 2022. In the first workshop, intervenors raised concerns about a PGE subsidiary bidding into a competitive process hosted by PGE, arguing this would be inappropriately disadvantageous to other bidders.

In the second workshop, PGE clarified that PRR is intended to be an unregulated portion of the Company in order to ensure that the Company could realize the tax benefits of avoiding normalization without violating IRS rules. PGE acknowledged it has not yet received a Private Letter Ruling (PLR) from the IRS indicating that PGE could realize the tax benefits in this manner, noting the IRS requires that there be a concrete project before it will issue such a ruling. PGE did indicate that it has worked with consultants to know what to expect from a future PLR.

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[10] *Application*, p. 5.
[11] PGE's *response* to Staff Data Requests 4 and 5 contained in Attachment 4.
[12] *Application*, p. 12.
[13] Id.
[14] *Application*, p. 10.
[15] *Application*, p. 2.

When asked, the Company noted that the bylaws and articles of incorporation exist but were not filed. The Company spoke about the bylaws and articles of incorporation at a high level to workshop attendees. These documents were later requested by Staff in data responses.

Staff also presented its initial position opposing PGE's filing and recommended conditions should the filing be approved. These recommendations were developed initially by Staff and then presented individually to the Oregon Citizens' Utility Board (CUB) and Alliance of Western Energy Consumers (AWEC) for feedback prior to the second workshop.

After the second workshop, Staff determined that it had more time than initially thought to pursue discovery, refine the conditions, and update its position. Staff circulated its revised, simplified conditions to members of the docket distribution list on Thursday, November 18, 2021, and indicated it had decided to change its recommendation to either approve the Application with no less than Staff's updated conditions or reject PGE's Application.

In the third workshop, Staff allotted time for intervenors to further discuss perceived competitive concerns that could arise from the establishment of PRR. Intervenors raised concerns that PGE's Application does not provide adequate separation of functions between PGE and PRR. At this third workshop, Staff also presented its revised conditions and discussed the motivation behind each condition. CUB also presented conditions of approval in the third workshop that are intended to supplement Staff's proposed conditions. The reasons behind each condition and intervenors' reactions to the conditions in the third workshop will be discussed later in this memo.

Staff's review included examining PGE's application, attached materials, and PGE's responses to eight Staff Information Requests. Staff reviewed the following issues in considering whether the Agreement is fair and reasonable and not contrary to the public interest:

1. Terms and Conditions of the Agreement;
2. Transfer Pricing;
3. Public Interest Compliance; and
4. Records Availability, Audit Provisions, and Reporting Requirements.

Staff concludes the analysis section of this memo by summarizing intervenors' reactions to Staff's and CUB's proposed conditions of approval at the third workshop and discussing the timing of this docket with PGE's upcoming RFP in UM 2166.

Terms and Conditions of the Agreement
In this docket, the Company seeks to provide various services to PRR. However, the Company's larger proposal is to establish an unregulated subsidiary to bid and execute renewable projects. Staff will discuss both the services provided in the MSA and elements of the Company's larger proposal.

Staff reviewed the Agreement and concluded it did not include any unusual terms or conditions. As shown in the Company's supplemental filing on October 25, 2021, the terms and conditions of the agreement of the MSA are unchanged but for the addendum that adds PRR to the MSA.

Staff notes that PGE's larger proposal to establish an unregulated subsidiary to sell power back to PGE will require greater scrutiny in any filing seeking approval for the transaction. However, to determine whether PGE's request to take this first step toward that transaction should be approved at this time, Staff reviewed PRR's articles of incorporation and bylaws that were provided to Staff in response to Staff Data Request 1.

After reviewing both documents and engaging in the workshops, Staff notes that there are some concerns about the freedom given to PRR in its bylaws and articles. Namely, there is nothing restricting PRR from bidding into other companies' RFPs and nothing guaranteeing that PRR employees working on a bid aren't also working on other parts of PGE's RFP at the same time. The first concern presents operational risk that could trickle down to ratepayers, and both concerns present potential competitive risks. Staff's proposed conditions 1, 2, and 4 seek to address and mitigate these concerns. PGE's Application frames the subsidiary purely as a way to avoid restrictive ITC normalization rules for regulated utilities, so it is unclear to Staff why freedom to bid outside of PGE's own RFPs is necessary.

The Code of Conduct mentioned in condition 2 is meant to ensure that employees working for PGE and PRR are fairly engaging in any RFP proceedings and to supplement the measures taken by the Independent Evaluator to ensure that the affiliate bid adheres to the competitive bidding rules. Staff intends to develop the Code of Conduct in the event PGE's application is approved.

Transfer Pricing
PGE indicates that the services provided in this docket will be provided at the higher of cost or market unless otherwise approved by the Commission in accordance with OAR 860-027-0048(4)(b).[16] Should the Commission approve the Company's request in this docket, this would apply to all services PGE provides to PRR. To ensure that there is proper bookkeeping to back up the services provided to PRR by PGE, Staff proposes conditions 7, 8, and 10.

Although this docket does not ask for approval of any executed contract wherein PGE purchases power from PRR, Staff believes that it is appropriate to include additional controls to ensure that the price of power sold from PRR to PGE is the result of an unbiased competitive process. To that end, Staff proposes condition 3 to ensure that any PRR bid is proposed the same manner as a bid by a third-party IPP engaging in a PGE RFP.

CUB's four proposed supplemental conditions provide added controls on financing for the affiliate, rate of return on investment for voluntary renewable energy tariffs, and the structure of potential affiliate bids. Staff takes no position on CUB's supplemental conditions.

Public Interest
The Commission customarily applies a "no harm" standard in determining what is "not contrary to the public interest" in matters involving affiliated interest transactions. *See, e.g., In the Matter of a Legal Standard for Approval of Mergers*, Commission Order No. 01-778 at 10 (September 4, 2001). Staff does not think PGE's current filing meets the "no harm" standard without proper controls. Staff's broad concerns are largely related to the competitive process and ratepayer risk and benefit. To address the "no harm" standard, Staff has developed controls that seek to maintain the integrity of the competitive process, limit ratepayer risk, and share benefits of successful PRR projects. In particular, there are four areas of public interest concern for which Staff developed controls.

First, Staff does not believe that PRR's bylaws and articles of incorporation adequately protect ratepayers; this is addressed by Staff's first two conditions previously discussed. Second, Staff believes that use of an unregulated arm undercuts some of the safety to ratepayers that results from PGE being a fully vertically integrated utility. Third, Staff is concerned that the benefits from an under-budget PRR project would not be passed onto ratepayers in the same way that they would be with a PGE project. Finally, Staff notes that that the Company and US Congress are actively engaged in other activities to eliminate the tax inefficiencies caused by normalization, therefore it is unclear that

[16] *Application*, p. 9.

approval of the Company's Application addresses ITC normalization while meeting the "no harm" standard. Staff addresses these final three concerns with controls discussed in this section.

Staff believes that creating an unregulated entity engaged in power operations introduces risk that could cause harm to ratepayers. Although PGE's current credit ratings are strong and not in any imminent danger of falling, Staff is concerned that a series of over budget or failed projects that would have otherwise been regulated by the Commission or been the responsibility of outside IPPs could ultimately lead to a credit rating drop. Staff's concern is underscored by PGE's intent to fund PRR projects using a parental guarantee on behalf of PRR. PRR presents further risk because PGE has yet to obtain a PLR, leading to potential unexpected risks associated with the flow through of tax benefits. Staff has created condition 5 to ensure that ratepayers are not held responsible for any of these problems that may be caused by PGE's unregulated subsidiary, PRR. Condition 6 ensures that the Commission gets adequate notice should any events occur that impact PRR's operations. Staff believes that these conditions are necessary to meet the "no harm" standard in this docket.

Staff's third concern is that benefits from PRR may not be fully passed onto ratepayers. While this may happen in many ways, the example that Staff would like to use is a PRR project that comes in under budget. If an identical project with identical tax benefits were under PGE's regulated arm, these avoided costs could be passed onto ratepayers through existing Commission processes. However, under a PPA structure, benefits from extra successful operations wouldn't necessarily get back to ratepayers. This is addressed by condition 9, which ensures that positive PRR earnings count towards any PGE earnings test while negative earnings do not. This ensures that the "no harm" standard is met by benefiting ratepayers if PRR is exceptionally successful and leaving ratepayers indifferent otherwise. Staff views Condition 9 as a way to allow shareholders to realize earnings from the Company's unregulated arm while passing benefits onto ratepayers only in the event that earnings are exceptionally high, thereby sharing benefits between shareholders and ratepayers.

Finally, Staff believes that an affiliate structure may not be the best way to avoid the tax inefficiency caused by ITC normalization, particularly given the Company's other activities and bills in Congress. The Company spends a significant portion of its initial filing discussing the problems caused by ITC normalization and how the affiliate structure is the best way to address these problems. ITC normalization has been identified as a problem within the utility sector for many years, and Staff recognizes that the inefficiencies caused by ITC normalization may be significant and could potentially be a hindrance to renewable development.[17] Staff agrees that ITC normalization

[17] See *Attachment* 3.

hinders PGE's ability to win renewable bids in its own RFP, particularly when competing against IPPs who are not also subject to ITC normalization laws.

PGE frames this subsidiary as the best path for overcoming the barrier to meeting emissions targets required by Executive Order 20-01 and HB 2021. However, as PGE acknowledges, it may not be the only path.

PGE notes that it had worked with Senator Ron Wyden on his Clean Energy For America Act and added a clause to eliminate ITC normalization for utilities. To quote CEO Maria Pope:

> The structure of the tax credits in the Bill were particularly important to us. As you know, we worked with Senator Wyden on tech-neutral tax credits. Those are reflected in what was discussed yesterday by the President. And also important to us is tax normalization that's included in – we're still working very focused on normalization for transmission and in particular for storage.[18]

Maria Pope later states, "we remain hopeful, and the industry is focused on resolving the tax normalization issues."[19]

This bill is currently working through Congress and has a chance of passing. If the bill indeed passes, establishing a subsidiary is a redundant measure and one that appears riskier to ratepayers.

Staff believes that a subsidiary is a second-best solution to the ITC normalization issue while changing the laws around ITC normalization is the most preferred. Should the laws change, a subsidiary with the sole purpose of bidding into PGE's own RFP presents unnecessary ratepayer risk. To address this, condition 11 states that in the event Congress addresses the ITC normalization issue identified by PGE, PRR shall cease creating bids and only function to manage the PPAs of projects already in service for the remainder of their life.

Staff views condition 11 as a way to address the problems with ITC normalization experienced by the Company while eliminating the ratepayer risk should the problems with ITC normalization go away through other means.

[18] See *Attachment* 2, p. 18.
[19] See *Attachment* 2, p. 20.

Records Availability, Audit Provisions, and Reporting Requirements
The Commission retains the ability to review all of PGE's affiliate transactions through both its annual affiliated interest report and in general rate case filings.

Staff's conditions 4, 6, 8, and 10 provide the Commission additional access to PRR records, and the ability to review and amend any changes to PRR governing documents and be informed of PRR activities.

Stakeholder Reaction to Proposed Conditions
In the third workshop for this docket, Staff and CUB presented their proposed conditions should this docket be approved. In this section, Staff will summarize stakeholder suggestions to and discussion around the proposed controls. The suggestions and discussions do not necessarily represent stakeholders' official positions on particular issues. While writing this memo, Staff contacted all stakeholders to confirm that Staff's notes about the discussion from the third workshop were accurate.

- **Staff Condition 1: PRR's sole and exclusive purpose shall be limited to bidding into PGE's RFPs and building any subsequent successful bids for cost-of-service customers unless otherwise approved by the Commission.**
    - PGE suggested striking this condition as the Commission already has authority over agreements between PGE and PRR. Calpine Solutions raised concerns about the competitive impacts arising from the exclusion of this condition.
- **Staff Condition 2: PGE employees working on a PGE RFP shall enter into a Code-of-Conduct agreement whose text and terms preclude the availability of any competitive advantage vis-à-vis any non-PGE RFP bid participant. The Code-of-Conduct shall include generation and transmission operations and information other than what is publicly available.**
    - PGE suggested removing the language to establish a Code of Conduct and revising this condition to align with existing competitive bidding rules as the Commission already has adequate protection for benchmark and affiliate bids. New Sun raised concerns that the Code of Conduct is not

adequately fleshed out and should be completed before approval of this docket. This concern was echoed by Calpine Solutions and NIPPC.

- **Staff Condition 3: Any PRR bid into a PGE RFP shall exclude explicit recovery of any decommissioning costs, but such costs shall be recovered implicitly through the pricing regime.**
  - PGE recommended removing the language regarding decommissioning costs and putting it into Condition 5, which already includes controls about ratepayer protection.
- **Staff Condition 4: PGE and PRR will submit any amendments or changes to the following documents to the Commission for approval:**
    - **PRR's Articles of Incorporation,**
    - **PRR's Bylaws, and**
    - **Any parental guaranty from PGE on behalf of PRR.**
  - PGE suggested striking the parental guaranty from this list and modifying this condition to say that PGE need only provide the listed documents for informational purposes rather than for approval by the Commission. PGE also suggested changing the names of the documents listed to better align with the actual names PGE uses for the documents.
- **Staff Condition 5: PGE utility customers shall be held harmless from any adverse rate impacts that may be caused by PRR. PGE bears the burden of demonstrating that its ratepayers are held harmless. These adverse impacts include but are not limited to:**
    - **Flow through of tax benefits;**
    - **Startup costs associated with PRR;**
    - **Operational costs associated with PRR or any PRR projects;**
    - **Changes in PGE's cost of capital or cost of long-term debt associated with PRR; and**
    - **Production problems, poor performance, or cost overruns with PRR projects.**
  - PGE suggested making two changes to this language: adding the language about decommissioning costs from Condition 3 and adding language stating that the ratepayers are held harmless from costs to the extent that these costs are not already included in a PPA.
- **Staff Condition 6: PGE agrees to report to the Commission, any event that materially impacts the operations and cost structure of any PRR project within 10 business days of becoming aware of such an event.**
  - PGE suggested removing the word "materially" from reporting requirements and instead report only things that affect PRR's ability to perform its contractual obligations. PGE notes that it is not required to inform the Commission of PPA contract breaches. NIPPC raises concerns that PGE's suggested modifications to the language are too

broad, citing the example that a Company near default may still be able to perform its contractual obligations.

- **Staff Condition 7: PGE and PRR will not comingle any assets, cash flows, or financial accounts and shall explicitly identify assets, cash flows, and financial accounts by company.**
    - PGE suggested striking this condition as it is already addressed by Condition 8.
- **Staff Condition 8: PRR will maintain separate financial books and records from PGE and maintain robust systems to track time employees spent on PRR business.**
    - No stakeholders brought up concerns about this item in the third workshop.
- **Staff Condition 9: Any earnings from PRR will be reported in PGE's annual Results of Operations and positive earnings from PRR will count towards any earnings tests conducted by the Commission. Negative earnings will not count in earnings tests conducted by the Commission.**
    - PGE suggested striking this language as it provides asymmetrical risk between ratepayers and shareholders. After further discussion, PGE floated the idea of considering using both PRR's earnings and assets for an earnings test rather than just earnings as was proposed by Staff.
- **Staff Condition 10: The Commission shall be given unrestricted access to any documents, internal communications, meeting minutes, financial statements, books, and records from PGE and PRR.**
    - PGE suggested modifying the language on Commission access to PRR materials to remove the word "unrestricted" and add language that give the Commission access to the materials contained in Condition 10 upon request and subject to existing law and privilege.
- **Staff Condition 11: In the event that laws are relaxed to no longer require that regulated utilities normalize ITC benefits, PRR shall no longer be allowed to submit bids into any PGE RFP. PRR shall still be allowed to operate any existing facilities for the duration of any existing PPA.**
    - PGE suggested striking this condition as it is a duplicative control since PGE and PRR agreements already go to the Commission for approval.

AWEC asked whether Staff's initial condition should be modified to cease PRR future ability to bid should ITCs expire.

- **CUB Condition 1: PGE only uses its most recently Commission approved Oregon capital structure for financing affiliate energy supply contracts.**
    - PGE suggested striking this control as it is overly restrictive, and third-party PPAs are not beholden to a particular capital structure.
- **CUB Condition 2: PGE agrees to comply with Order No. 21-091, Condition 7 and will share some of its rate of return on the investment with other utilities customers for affiliate transactions for green tariff customers.**
        - **As an alternative to this condition, PGE commits to not use affiliate PPAs for green tariff options.**
    - PGE suggests striking everything after the words "Condition 7."
- **CUB Condition 3: PGE commits to not request an incentive on Affiliate energy supply contracts from the Commission.**
    - PGE suggested eliminating this condition because there are no current frameworks for incentives on PPAs.
- **CUB Condition 4: PGE commits to only structure affiliate energy supply contracts on levelized basis.**
    - PGE suggested adding language to this condition stating that this condition holds subject to any lender or financing requirements.

Timing with PGE's RFP
Staff notes that bids in PGE's upcoming RFP are due by January 17, 2022. Further, as per ORS 757.495, the Commission must issue a ruling on this docket within 90 days of the submitted contract, which means the final day to issue a ruling is January 23, 2022. That means that the last available public meeting that would let participants know whether PRR is participating in the RFP is January 11, 2022.

However, Staff recommends that the Commission come to a decision on this docket prior to that date in order to give PGE and other participants a greater level of certainty when engaging in the RFP.

<u>Conclusion</u>

Staff concludes, based on its review, that PGE's Application involves an affiliated interest transaction that passes the "no harm" standard necessary only if subject to Staff's eleven conditions. Staff's recommended conditions are set forth in Attachment 1.

PROPOSED COMMISSION MOTION:

Approve PGE's Application for Approval of an Affiliate Interest Agreement with PRR subject to no less than the conditions set forth in attachment 1

OR

Reject PGE's Application.

PGE UI 461 Affiliated Interest Agreement with PRR

Attachment 1 – Proposed Conditions

Staff's Proposed Conditions

1. PRR's sole and exclusive purpose shall be limited to bidding into PGE's RFPs and building any subsequent successful bids for cost-of-service customers unless otherwise approved by the Commission.
2. PGE employees working on a PGE RFP shall enter into a Code-of-Conduct agreement whose text and terms preclude the availability of any competitive advantage vis-à-vis any non-PGE RFP bid participant. The Code-of-Conduct shall include generation and transmission operations and information other than what is publicly available.
3. Any PRR bid into a PGE RFP shall exclude explicit recovery of any decommissioning costs, but such costs shall be recovered implicitly through the pricing regime.
4. PGE and PRR will submit any amendments or changes to the following documents to the Commission for approval:
   A. PRR's Articles of Incorporation,
   B. PRR's Bylaws, and
   C. Any parental guaranty from PGE on behalf of PRR.
5. PGE utility customers shall be held harmless from any adverse rate impacts that may be caused by PRR. PGE bears the burden of demonstrating that its ratepayers are held harmless. These adverse impacts include but are not limited to:
   A. Flow through of tax benefits;
   B. Startup costs associated with PRR;
   C. Operational costs associated with PRR or any PRR projects;
   D. Changes in PGE's cost of capital or cost of long-term debt associated with PRR; and
   E. Production problems, poor performance, or cost overruns with PRR projects.
6. PGE agrees to report to the Commission, any event that materially impacts the operations and cost structure of any PRR project within 10 business days of becoming aware of such an event.
7. PGE and PRR will not comingle any assets, cash flows, or financial accounts and shall explicitly identify assets, cash flows, and financial accounts by company.
8. PRR will maintain separate financial books and records from PGE and maintain robust systems to track time employees spent on PRR business.
9. Any earnings from PRR will be reported in PGE's annual Results of Operations and positive earnings from PRR will count towards any earnings tests conducted by the

Commission. Negative earnings will not count in earnings tests conducted by the Commission.

10. The Commission shall be given unrestricted access to any documents, internal communications, meeting minutes, financial statements, books, and records from PGE and PRR.
11. In the event that laws are relaxed to no longer require that regulated utilities normalize ITC benefits, PRR shall no longer be allowed to submit bids into any PGE RFP. PRR shall still be allowed to operate any existing facilities for the duration of any existing PPA.

CUB's Proposed Conditions

1. PGE only uses its most recently Commission approved Oregon capital structure for financing affiliate energy supply contracts.

2. PGE agrees to comply with Order No. 21-091, Condition 7 and will share some of its rate of return on the investment with other utilities customers for affiliate transactions for green tariff customers.

    a. As an alternative to this condition, PGE commits to not use affiliate PPAs for green tariff options.

3. PGE commits to not request an incentive on Affiliate energy supply contracts from the Commission.

4. PGE commits to only structure affiliate energy supply contracts on levelized basis.

Attachment 2 – PGE Earnings Call Transcript

Portland General Electric Company Transcript Earnings Call

S&P Global Market Intelligence – Oct. 29, 2021

Portland General Electric Company (NYSE:POR)

Call Participants

Executives

- **James A. Ajello**
  Senior VP *of* **Finance**, **CFO** & **Treasurer**
  Portland General Electric Company
- **Jardon Jaramillo**
  Senior Director *of* **Investor Relations**, **Treasury** *and* **Risk Management**
  Portland General Electric Company
- **Maria MacGregor Pope**
  President, **CEO** & **Director**
  Portland General Electric Company

Analysts

- Andrew Levi
  Former Portfolio Manager
  ExodusPoint Capital Management, LP
- Brian J. Russo
  Research Analyst
  Sidoti & Company, LLC
- David Christian Peters
  Research Analyst
  Wolfe Research, LLC
- Insoo Kim
  Equity Analyst
  Goldman Sachs Group, Inc., Research Division
- Julien Patrick Dumoulin-Smith
  Director and Head of the US Power, Utilities & Alternative Energy Equity Research
  BofA Securities, Research Division
- Paul Patterson
  Analyst
  Glenrock Associates LLC

- Peter J. Bourdon
  Analyst
  Mizuho Securities USA LLC, Research Division
- Shahriar Pourreza
  Managing Director and Head of North American Power
  Guggenheim Securities, LLC, Research Division
- Travis Miller
  Director of Utilities Research and Strategist
  Morningstar Inc., Research Division

Presentation

Operator
Good morning, everyone, and welcome to the Portland General Electric Company's Third Quarter 2021 Earnings Results Conference Call. Today is Friday, October 29, 2021. This call is being recorded. [Operator Instructions]

For opening remarks, I'd like to turn the conference call over to Portland General Electric's Senior Director of Investor Relations, Treasury and Risk Management, Jardon Jaramillo. Please go ahead, sir.

Jardon Jaramillo
Thank you, Jonathan. Good morning, everyone. I'm pleased that you're able to join us today. Before we begin this morning, I'd like to remind you that we have prepared a presentation to supplement our discussion, which we'll be referencing throughout the call. The slides are available on our website at investors.portlandgeneral.com.

Referring to Slide 2. Some of our remarks this morning will constitute forward-looking statements. We caution you that such statements involve inherent risks and uncertainties, and actual results may differ materially from our expectations. For a description of some of the factors that could cause actual results to differ materially, please refer to our earnings press release and our most recent periodic reports on Forms 10-K and 10-Q, which are available on our website.

Leading our discussion today are Maria Pope, President and CEO, and Jim Ajello, Senior Vice President of Finance, CFO, and Treasurer. Following their prepared remarks, we will open the line for your questions.

Now, it's my pleasure to turn the call over to Maria.

Maria MacGregor Pope
Good morning, and thank you, Jardon, and thank you all for joining us. Hot summer weather and power market volatility had a significant impact on our region and on our results this quarter.

Turning to Slide 4. We reported net income of $50 million or $0.56 per share for the third quarter of 2021. This compares with a loss of $17 million or $0.19 per share for the third quarter of 2020. Year-to-date, financial performance is on track. And despite third quarter volatility in the energy markets and higher O&M, we are reaffirming our 2021 earnings guidance of $2.70 to $2.85 per share. Our long-term outlook remains unchanged, and we are reaffirming our 4% to 6% long-term earnings growth guidance.

Overall, our business is strong, driven by load growth from the technology and digital sectors as well as elevated residential use due in part to the hot summer weather and continued COVID constraints. Year-to-date **revenue is up 12% versus 2020** and **for** the **quarter**, **up 17% versus last year**. Jim will cover third quarter results in more detail, provide regulatory and capital updates and discuss the outlook for the rest of the year.

The ongoing impacts of climate change underscore the importance of investments and actions that we are taking to rapidly transition to a clean energy future, and meet our 2030 decarbonization goals, while also ensuring that we have sufficient capacity. We estimate that our **2030 targets** will require approximately 1,500 to 2**,000 megawatts** of **additional carbon-free resources** and approximately **800 megawatts of non-emitting capacity resources** in addition to removing coal from our portfolio.

We're seeking approximately 1,000 megawatts of renewables and non-emitting capacity resources as part of our RFP, which will be issued in December. As part of this procurement, we plan to add 375 to 500 megawatts of renewables to our portfolio. We will also bring on approximately 375 of non-emitting dispatchable capacity. We will work with the OPUC and parties to evaluate opportunities to procure additional resources to the types of projects submitted in the IRP process -- excuse me, the RFP process, make sense for customers, and are attractively priced. We could see procuring about 1/3 of our clean energy resources needed to meet the 2030 emissions target reductions with this RFP.

We not only need more renewables, we need to upgrade the grid to integrate these resources, making it easier for customers to participate in demand response and distributed energy programs helping to keep service reliable and affordable. In our recent distributed resource -- excuse me, distributed system plan, we lay out plans for the grid of the future that supports robust two-way energy flows and better manages energy use, especially during peak periods. We estimate that as much as 25% of flexibility needed to meet our decarbonized future would come from customers and distributed energy resources such as solar panels, batteries, electric vehicles.

During the 2021 summer heat dome, we worked with customers to save 62 megawatts of power equivalent to powering 25,000 homes. We're working to significantly grow this program to 500 megawatts by the end of 2023. We are very pleased to have been selected by the Department of Energy as part of their Connected Communities program and are working with local DE&I groups on the placement of resources such as batteries, two-way EV charging, and solar panels to ensure that our customers and underserved communities participate in this clean energy transition.

As one of the early participants in the western energy imbalance market, we have been a leader in advocating for the expansion and strengthening of wholesale markets to increase reliability, accelerate decarbonization, and lower costs for customers. PGE and our utility partners across the West are working to bolster reliability planning, advance integrated markets, and examine the benefits of a western regional transmission organization. Throughout these processes, we will continue to advocate for rigorous resource adequacy standards.

Sustainability is foundational to our business. In September, we published our ESG report, building upon our #1 ranked voluntarily -- voluntary renewable program. Sustainability is part of the fabric of everything we do, including financing. We recently adopted a **green financing framework** under which we successfully **placed $150 million in green bonds**. Yesterday, we filed a **rate case** with the **F**ederal **E**nergy **R**egulatory **C**ommission to review our third-party **transmission revenue**. The revenue that we received from these new prices will offset retail customer prices through a revenue credit. We continue to make progress on our **2022 general rate** case and have reached **settlements** with stakeholders in October that resolves the **cost of equity** and gives **9.5%** as well as a **50-50 cash structure**. We look forward to working with stakeholders on the remaining items.

Finally, I'm pleased to **welcome Dawn Farrell** to our **Board of Directors**. **Dawn retired** as **President** and **CEO** of **TransAlta** in **March**. Her deep experience in the energy sector as well as her leadership in transforming a thermal-based generation company to a leading **clean renewable energy company** will be important as we advance our own transformation.

Now, I'd like to turn the call over to Jim.

James A. Ajello
Thank you, Maria, and good morning, everyone. Our third quarter results reflect the ongoing opportunity and the challenge as the economy enters a new normal. We experienced strong load growth from higher demand and hotter weather. At the same time, volatility in the power markets was evident throughout the summer.

The fundamentals of our economy remained strong and are fueling strong growth in energy demand and a growing labor market with continued job growth in the region. This quarter, we had strong deliveries across our customer segments with additional benefit from favorable weather. Our high-tech and digital services sectors continue to grow at a rapid pace, 9% higher when compared to Q3 2020. Customers are expanding capacity, and we've seen an uptick in site selection activity by data center developers and others. Residential usage remained significantly elevated as remote work continues. We anticipate these trends to continue, and this has contributed to our strong year-over-year load growth.

Turning to Slide 5. We reported GAAP income of $0.56 per share in the third quarter of '21 compared to a GAAP loss of $0.19 per share in the third quarter of 2020. Non-GAAP income for the third quarter of 2020 is $0.9 after removing the negative impact of the energy trading losses.

I'll cover our financial performance quarter-over-quarter on Slide 6. Beginning with the loss of $0.19 per share for the third quarter of 2020, we will add back the $1.09 one-time impact of the energy trading losses. We experienced a $0.37 increase in total revenues, primarily due to the strong economy driving growth in our service territory, with the balance due to warmer weather. This represents a 17% year-over-year increase in total revenues. Offsetting this was a $0.39 of unfavorable power cost. We experienced substantially higher market prices due to warmer weather and increased regional demand for capacity as well as lower renewable generation. As a result, we are forecast to be above the $30 million threshold to begin customer cost sharing pursuant to our power cost adjustment mechanism.

Through the quarter, we have deferred $27 million, which represents 90% of the variance above that threshold. We anticipate the regulatory process related to this deferral will begin in 2022 after the pending rate case concludes. Our power costs this summer were not materially impacted by rising natural gas prices. Our portfolio is well positioned and a bit long to balance gas price fluctuation, and we have **significant gas storage at** the 4.1 billion cubic foot **North Mist** facility that we can draw on as needed.

There was an $0.11 decrease to EPS from costs associated with our fixed operating expenses, including $0.03 for enhanced **wildfire mitigation**, $0.04 of additional **vegetation management**, including work that was delayed as we focused on storm restoration during the second quarter, $0.02 of service restoration costs, and $0.02 of miscellaneous other expenses. There was an $0.18 decrease to EPS from administrative expense. Half of the year-over-year increase is attributed to items that were unique to 2020 including $0.07 in adjustments to incentive programs following the **energy trading losses** in the prior period, and $0.02 from the deferral of **bad debt** following the approval of the **COVID**-19 deferral. The remaining administrative expense can be attributed to $0.06 for outside services to support improvements to our customer experience, a $0.02 increase in employee benefit expenses, and $0.01 from miscellaneous other expenses.

While O&M was higher this quarter when compared to Q3 2020, on a year-over-year basis, our costs have increased only 2% annually since 2019. The fact that we have reduced planned outages by 29% year-over-year, stood up a large wildfire prevention program and greatly increased vegetation management is a testament to the efficiency we built into the O&M program. Managing costs consistent with inflation while increasing wildfire resiliency, improving our customer experience, and growing our digital capabilities demonstrates the effectiveness and efficiency of our workforce as well as the use of technology. Finally, there was a $0.03 decrease to EPS from the following items: $0.03 benefit from lower depreciation and amortization due to planned retirements, $0.04 of higher tax expense due to the timing difference of asset retirements in 2020, and $0.02 from other unfavorable miscellaneous items.

Turning to Slide 7. Last month, we reached an agreement with stakeholders on cost of capital in our 2022 general rate case. Our agreement supports a capital structure of 50% debt, 50% equity, and a 9.5% allowed ROE. We see this as a constructive outcome and look forward to discussing remaining unsettled issues with parties in the case. As you saw earlier this month, we made several regulatory filings, which we shared -- in which we shared our plans to advance the strategy to meet our targets for reducing greenhouse emissions in the power we serve to customers.

Maria discussed our RFP plans earlier in this call. We still plan to bid in benchmark resources into the RFP process. To support our bids, we filed for an affiliated interest entity that will help support our decarbonization interests. Our proposal is intended to address certain structural tax disadvantages encountered by utilities due to the unintended consequences of tax normalization requirements. The affiliate interest would provide a greater price benefit to our customers as PGE decarbonizes its generation portfolio.

Turning to Slide 8, which shows our updated capital forecast through 2025. We increased our capital expenditure forecast by over $100 million this quarter. This increase is concentrated in 2022 and is primarily associated with grid-based investments. With our recent settlement in the GRC assuming approval by the OPUC, this affirms that we will not need to issue equity in 2022 to meet our capital requirements. Unless there is a significant renewable addition stemming from the aforementioned RFP. We continue to maintain a solid balance sheet, including strong liquidity and investment-grade ratings accompanied by a stable credit outlook. Total available liquidity at 9/30 is just over $1 billion.

At PGE, sustainability is woven into the fabric of who we are as a company, and we stand behind that through our actions as an organization including in our financing plans. This quarter, we renewed and increased by $150 million of revolving credit facility to include sustainability-linked performance metrics. We also **refinanced** the **Wheatridge** Renewable Energy facility with low-cost debt under a **green bond** in alignment with our green financing framework. The demand for this was evident as it was nearly 6x oversubscribed. Our investors are keen to purchase debt linked to sustainable investments. Going forward, we will seek out opportunities to tie our long-term debt toward our sustainability strategy through capital investments. Not only are these actions good for our business, but they are also good for society.

Turning to Slide 9. Our year-to-date 2021 performance remains on track, and we reaffirm our guidance range of $2.70 to $2.85 and remain on track to achieve long-term earnings growth guidance of 4% to 6% from the 2019 base year. The picture for 2021 and beyond remains clear: strong growth in customer demand for clean, affordable, safe, reliable, and equitable energy paves the way for us to execute on our long-term financial targets and deliver value for customers and investors alike.

And now operator, we're ready for questions.

Question and Answer

Operator

[Operator Instructions] Our first question comes from the line of Insoo Kim from Goldman Sachs.

Insoo Kim
My first question, I think is more financial in nature. Just, Jim, for the year as we think about the year-to-date results and you're reiterating the midpoint of the -- or I guess the guidance range that you raised last year seems to imply a pretty healthy fourth quarter earnings relative to if you look at 2019 fourth quarter or 2020 fourth quarter results. Can you just help us generally piece together some of the moving parts that exist there?

James A. Ajello
Yes. Thanks, Insoo. As I understood your question, you're trying to, in effect, walk from where we are today to the result of the 2021 guidance in effect what we might do in the fourth quarter. So let me try to -- do I get that right?

Insoo Kim
Yes, that's correct.

James A. Ajello
Okay. Perfect. Okay. So let's look back to the fourth quarter of 2020. There, the earnings were $0.57 per share, you may recall, but also we recorded an asset retirement obligation for our Sullivan hydro facility, a facility that's well over 100 years old in fact, and that was $0.17 a share. We also adjusted incentives for that fourth quarter as non-GAAP earnings were picking up speed in the fourth quarter. So in reality what happened was the way I look at the fourth quarter and I walk to the fourth quarter of this year, we had about $0.22 between the ARO and the incentive adjustment added to the $0.57 to normalize the fourth quarter of 2020, which gets you to about $0.79. And that in fact gets you to about the midpoint. If that were to reoccur again in 2021 of the present range. Does that help?

Insoo Kim
Okay, so the ARO is a pretty big component of this?

James A. Ajello
Yes. The ARO is $0.17 a share, incentive adjustment is $0.05, $0.22, add that to $0.57, you would normalize fourth quarter of $0.20 to $0.79 a share. And we're at $1.98, as you would know, for the year-to-date presently, right?

Insoo Kim
Right. Okay. That definitely helps. Thank you for that. Second question, Maria, just a broader picture, I think it's no question that the state of Oregon has been a leader in proposing and advocating, and acting on the clean energy transformation and Portland is a big component of that. When we think about the pending reconciliation package that is out there and the potential for extensions of tax credits and some changes to how those mechanisms will work, how does that -- how do you think about that impacting or creating incremental opportunities maybe even

over the next 5 years in terms of different clean energy investments that are coming about for you guys?

Maria MacGregor Pope
Sure. First of all, it's a great question, and we were very pleased to see the announcements yesterday with significant investments that will help us and others transition to a clean energy economy. The structure of the tax credits in the Bill were particularly important to us. As you know, we worked with Senator Wyden on tech-neutral tax credits. Those are reflected in what was discussed yesterday by the President. And also important to us is tax normalization that's included in -- we're still working very focused on normalization for transmission and in particular for storage. And so, that -- those remain goals of ours. Should that not take place, the affiliate filing that Jim talked about will give us the level playing field to continue to move forward with important components from a utility standpoint for our customers around battery storage and others so that we can get the very lowest cost for customers as we make this important transition.

Operator
Our next question comes from the line of Julien Dumoulin-Smith from Bank of America.

Julien Patrick Dumoulin-Smith
And congrats to Dawn as well. I don't know if she's there, but well done on bringing on more talent here. But if I could just jump into the rate case just real quickly here, two quick clarifications. So first off, just following the earlier settlement obviously on cap structure and ROE, how you frame the potential to settle other outstanding items and just the process therein? And then related to that, if you could clarify, given the capital structure and the 50-50 authorized, does that change any equity dynamics as far as you're concerned here?

James A. Ajello
Julien, it's Jim. I'll kick off. So to take your last question first, yes, it does and it gives me confidence that we **could go into 2022 without** the **issuance of any equity**. We're in very good shape from a balance sheet standpoint. Our cost of financing is able to fund even that increased capital program that I spoke of a moment ago, we changed that from $550 million next year to $655 million. And I'll just go further, and Maria may want to add in, in a moment. But we received comments earlier this week. We're evaluating those. I would say that this is a normal part of the process. Just want to remind everyone that we deferred filing a bit here earlier this year in consideration of the community impacts on COVID. So I think we were -- we respected everybody's interest in terms of timing. We feel we put forward a pretty modest proposal, frankly, about 3.9%. 2% of that was in the AUT itself. It's **largely** a **capital case**. We **added $993 million** of **capital**, between the last time rates were filed we have kept, as I mentioned in the remarks a moment ago, our O&M pretty tight over that period of time. So -- and as you would know, the **company has a history of settling**. So we are about to get into a process where we will exchange information and hopefully get to that outcome. But it's too soon to predict anything at all. Maria, anything to add?

Maria MacGregor Pope
Well, I want to emphasize that as we've made decisions around our rate case, we have been particularly cognizant of the economy and particularly on those most impacted by the pandemic and we, as the result, delayed filing our rate case. I would also say we were able to do that because of all of the tremendous work that our colleagues here at Portland General have done. In Jim's prepared remarks he talked about the efficiencies that we have gotten from better use of technology, digital, driving efficiencies across our entire company. As a matter of fact, our planned outages are down significantly over 20%. We have seen better utilization of our assets, better work management flow, and there's no question that we are getting more work done than we have in the past. And I'm really encouraged that we were able to keep through all of the ups and downs of the last 18 months to 2 years, O&M increasing at only 2% annually. And this focus on cost, but more importantly, on efficiency and driving outcomes for customers has allowed us to have the flexibility to delay our rate cases. We brought on really important reliability capital, capital also in the compliance area. As Jim mentioned, we have really focused on vegetation management, wildfire protection. And then as you know, people are moving to Oregon, and we have quite a bit of expansion in our digital and high-tech areas. And so, we have built a number of new substations, we've expanded some other of our infrastructure, and it's really because of the good work of people at Portland General that we've been able to keep our prices as low as we are particularly in light of all of that's going on in our economy today.

Julien Patrick Dumoulin-Smith
Got it. Excellent. And just if I can pivot here to the affiliate dynamic just real quickly. You brought this up to seem somewhat novel. Can you speak a little bit more as to just how that might expand the opportunity or why pivot to this opportunity now given that you haven't used it in the past? I understand that tax normalization, obviously, has been an impediment out there and then maybe your level of confidence there, and now that you're pivoting to this strategic focus here on winning.

Maria MacGregor Pope

Sure. So first of all, we remain hopeful, and the industry is focused on **resolving** the **tax normalization issues**. And those discussions as you've seen Senator Wyden quoted and political and whatnot are very much in play. This is not -- this affiliate filing is not new. We've been talking about it for a long time and debating it. So it's very similar to many other affiliate filings that you see across the country. It'll allow us to **utilize tax advantages** to **reduce renewable costs from customers** -- for customers to allow for **more competition**. And really so that our customers can have the very lowest cost energy that's reliable as we transition to ever-increasing amounts of new renewables. We have -- we, as well as many others, have very aggressive 2030 and 2040 goals, and we think this is an important tool in that toolbox.

James A. Ajello
Julien, I think I hear you asking the question why now and why us, and in addition to the structural disadvantages compared to the way independent power producers can accelerate those

tax credits, and we have to normalize them over the life of the asset 30 years let's say, **we're about** to **enter into** and **pivot into** a **very significant growth plan** in **renewables**. **We want to be** an **extremely active benchmark** and **owner** of **those assets**, and we need to level the playing field and have the tools to do that. We need a couple of thousand megawatts between now and the end of the decade, and we want to be in that mix. I **don't expect** to **win everything**, but we **expect** to **be very competitive**, and we need the tools to do that. And that's really the framework and why now we're doing that.

Operator
Our next question comes from the line of David Peters from Wolfe Research.

David Christian Peters
The question -- first question I just have is just on that variable power costs. Obviously, the magnitude of that seems fairly unprecedented and then the deferral of $27 million. Just curious how you expect this to play out exactly just because I think this is the first time you expect to kind of breach that? And then just kind of, particularly with the backdrop that you have several other kind of sizable deferrals pending that are outstanding along with the rate case, so are there any creative ways to kind of mitigate potential bill impacts for customers here going forward?

James A. Ajello
Dave, I would agree with your observations. My time here is fairly short, but I look back and I think you're right about the nature of the levels here. But so was the weather and the markets that we experienced over the summer time. So I look at the mechanism itself as -- and our deferral under that mechanism is highly formulaic. It's -- there are **deferrals**, and there are deferrals. This one, I believe, is -- can be objectively calculated at the level that we have recorded it. And so, I believe that this particular deferral is very straightforward, very verifiable. And the way it would work, typically I would say, but subject to discussion with OPUC is we would amortize that over a couple of year period starting, as I mentioned in the remarks, after we adjudicate this pending GRC that we have at the moment. So that's that one. And you refer to the other deferrals, which are substantial.

As you could calculate, they're nearly $150 million altogether, but they're very different in nature. There's the COVID deferral, which again is subject to I think a pretty straightforward calculation around debt -- bad debt. And then there are the more complex deferrals around the wildfires of 2020. And the last one being the biggest of all, which is the February storm cost. So I think I described these in terms of both size and ascending complexity. And I fully expect, since we don't have a securitization capability in the state at least not yet, we will have to sit down and agree on an amortization schedule. And as I described those deferrals, they will go from shorter to probably a longer period of time. So the latter deferrals that I mentioned probably over a number of years, maybe many years. So that's how I look at it, Dave, and that's how I would think about it going forward.

Maria MacGregor Pope

Dave, let me add a couple of things to that. We have gone through an extraordinary period of time. We obviously had the **pandemic**, we had wild -- very destructive **wildfires**, we had a once in 40-year **ice storm** where more than half of our customers were out of power, and we had over 700,000 distinct customer outages. We also had the **high heat dome events**, and it really has been an unusual point in time. Most utilities would use a **securitization** structure. And that I think is something that we will **explore with parties**. It's very important as well because we're able to take advantage of very low-cost debt rate. And so, that will certainly be something that we will pursue. I think it's really important as we look going forward around power costs that we -- that the PCAM is really just one link in the chain of power cost recovery. I think of this as kind of a four or five-step process.

The first one is our forecasting methodologies. And earlier this year, late last year, we made changes to some of our modeling assumptions with discussions with parties and the OPUC. And those changes allow for more volatility to be reflected in our modeling. And that's particularly important with the variability of hydro and wind. The second would be our AUT or our power cost filing that we do each year. We're able to true-up market prices for power as we go into the prompt year. And then third, really our **procurement strategy** and **derisking** through our power operations, and they have done an excellent job at that. And I'd say they're working very closely. This would be my fourth area in terms of plant operation and making sure that our plants have the utmost reliability on the most challenging days of the year, whether those be ice storms and freezing temperatures or high heat events.

And then finally, the PCAM comes in and provides a regulatory backstop for our extraordinary volatilities as we've experienced this summer. So I think these are really unusual times. As we look forward into 2022, and you can see -- we have been in discussions with parties around the AUT, we're about to -- we'll be locking down those numbers as we move forward. But about half of the $60 million increase that we're roughly forecasting is directly related to higher load. And so, that's a good variance. And we couldn't be more pleased with the expansion that we're seeing in the industrial commercial sector as well as with customer growth as people are still moving into our service territory into Oregon.

And then, we're seeing about the other half related to either derisking the portfolio with capacity and making sure that we have adequate reserves going into the year, and then also just higher prices that are reflected. One of the things that I'm really pleased is that our hedging strategy with regards to natural gas, which has been in place for almost a decade, and is really meeting -- our customers are not experiencing the volatility of natural gas prices. And so, it's nice to see when these practices make a bottom line difference to every bill we send out to our customers, and we're able to insulate them from the -- some of the volatility that we're seeing across markets in the energy space.

David Christian Peters
Great. Thank you for that detail. Second question I had just back to the rate case. We saw staff's testimony earlier this week and obviously, a big delta versus your guys' ask, which I don't think

is inconsistent with history, but could you maybe just comment on what you saw in there understanding that you think there's still a good chance of settlement? And then just chances on getting some of those proposed changes approved around the storm accrual and decoupling?

James A. Ajello
Yes, Dave. I'll start and Maria may want to add to it. You're right. I mean, I appreciate your comment, not inconsistent with history. We don't overreact to these things either. These are the kinds of things that happen in cases like this. I will tell you that I think we should pursue the GRC in all of its detail. **We desire** to **get to** a **settlement**. **But** the **deferrals** are on **separate tracks** in **separate dockets** and therefore, should be separated from the case, and that's our view, and that's the way it's set up to go forward here. And as you know, the settlement prospects here are always something that we try to do, and we will deal with the deferrals in due course, but they'll be on a separate track.

Maria MacGregor Pope
Yes. I don't think I have anything to add. We'll work collaterals with parties, we'll be transparent, and I think help everyone understand the magnitude of the past year to 18 months and the good work that we have done to address the issues the -- that mother nature has brought us and to create a more reliable and resilient utility as we go forward.

Operator
Our next question comes from the line of Shar Pourreza from Guggenheim Partners.

Shahriar Pourreza
Maybe just starting at a higher level. You guys obviously laid out some pretty **substantial energy** and **capacity needs through 2030**, and I understand it **won't necessarily all be utility-owned** as Maria obviously you highlighted it in the prepared remarks, but how should we sort of think about maybe this **opportunity** in the context of your guided 4% to 6% **growth**? In the past, we've talked about the current RFP pushing higher in that range. So would the size of the overall need be enough to get you to consider maybe guiding even higher?

James A. Ajello
Shar, it's Jim. So I will tell you our setup for the guidance range here is not including any generation facilities that we may be fortunate enough to compete and win for in this next round. In fact, I would anticipate a couple of IRPs in this decade, maybe two or three and successive calls for more resources. We've recently upped our expectations, and we've been encouraged to up our expectations given the march that we're on here. So just to make it clear, none of that ownership would be in the 4% to 6%. And also let's not forget here we're **backing out**, as **soon as practicable**, our **interest** in the **Colstrip plan**t, right? And we have accelerated depreciation that's been agreed to. It still needs to be approved finally by the Oregon PUC in the context of this rate case, but we have a settlement there to accelerate depreciation in 2025. So we're making a really strong pivot to a significant purchase and perhaps ownership program. But in terms of ownership, that's not in the guidance. Nor is the capital that we've laid out that -- to operate the system including any of the capital that we would need to build those assets.

Shahriar Pourreza
Got it. So just maybe -- just brings a follow-up. So is the current process, is that supportive of how you guide as in extending the runway? Or could it actually be accretive?

Maria MacGregor Pope
If I understand your question correctly, any additional -- as Jim mentioned, any **additional ownership opportunities** through the IRP, should those be the least costliest risk projects would be accretive to our 4% to 6% growth?

James A. Ajello
Yes, for sure. And you can expect, Shar, that we will capitalize those appropriately. But at the end of the day, we'll be accretive. Sure.

Shahriar Pourreza
Okay, that's -- thank you very much for that. And then just on the RFP process, right in the event you were successful, when would you be looking to do associate with equity? Would you automatically be eligible for an associate rider for recovery, or would you have to go back in for another GRC?

Maria MacGregor Pope
So we do have a renewable adjustment mechanism that allows us to track in renewable energy. So that's very favorable and it's a mechanism that we've used on numerous occasions and most recently with the Wheatridge Energy facility.

James A. Ajello
And I'll add, Shar, that we wouldn't know about the award periods until probably the spring and early summer. Construction would take place -- design and construction would take place later that year into '23 and '24, so financing would happen in that time frame. And we have such a terrific liquidity position that we could leg into any ownership without immediately needing to go into the market for much in the way of financing certainly, equity financing.

Operator
Our next question comes from the line of Peter Bourdon from Mizuho.

Peter J. Bourdon
Just to follow-up on the power cost side of things. Is there any more color you can give on what drove the volatility that you saw this quarter? And then secondly, what gives you comfort that, that volatility is not I guess the new normal going forward?

Maria MacGregor Pope
Sure. Well, in the West, and maybe even the rest of the country as you look at scorched trees all over the place, I think it's really important that we recognize the high heat events that we had. And so, that created -- we're able to forecast those events, but not too far out into the future. We also had quite a bit less hydropower in the region, and aligned with hydropower is actually wind generation as well. And that created quite a bit of volatility in market prices throughout the West

and those that we were exposed to. I would say that we particularly saw run-up before the day-ahead markets would have some of the highest prices. And then they would -- frequently would fall off during -- in real time. As we think about working across the West, we've seen additional liquidity as we're more integrated. And I would say, power and energy trading leaders are really looking at how we expand the integration and pooling of resources across the entire West, so whether that's to day-ahead markets and the expansion of the EIM with CAISO, whether that is through reliability discussions at the Northwest Power Pool or whether that's through other forums where people are really looking at how we manage going forward. We're fortunate to have, as I walked through, the ability to update our power costs and -- every year through the annual update mechanism. So we are able to reflect the learnings year-to-year into our future power costs and the reality of these market conditions. As you know, we've -- across the West have reduced a number of significant thermal plants and that's having an impact on -- as we get into scarce periods of time, there are less resources in standby that could come back on to the market. And as a result, I think we will continue to see volatility and we are learning and managing through it.

Operator
Our next question comes from the line of Travis Miller from Morningstar.

Travis Miller
You answered a lot of my questions in detail, I appreciate that. I want to go back to the CapEx increase. Can you talk a little bit more about that? What types of projects led you to increase that 2022 number, and what was the factor or factors during the quarter in the last 3 months that led you to raise that $100 million or so?

Maria MacGregor Pope
So let me build a little bit, Travis, on the answer I just gave to the prior question around reliability and markets. One of the things that's also really important is a tool in our toolbox. And I mentioned it in my prepared remarks, was that being able to use essentially 25% of the capacity and sort of shock absorber of markets in the distribution system. And so, as we move forward, we have accelerated our plans, around our distributed resource plans whether that's DERs, could be solar, battery storage, electric vehicles and their ability to charge and create a buffer, but also demand response programs. We have had one of the most robust energy conservation programs in the country, in fact, we lead in those areas. And so, all of this together combined with the infrastructure that needs to support a really smart, flexible grid as we integrate more renewables and try and reduce the impact of volatility is important. It's not just important to pricing, it's important to overall reliability. I'll let Jim talk to you a little bit more about the specific buckets of capital that we have, but please know that we are moving quickly to reflect the new realities of our markets and the need for greater sustainability in a carbon-free future.

James A. Ajello
Travis, I'll add that largely we don't think of CapEx as something that is temporal. We -- in the short term, we think of it as a long-term matter. So just looking at the '22, the reference to the

higher CapEx at $655 million versus $550 million, so largely that 60% -- 65% in fact grid-related just proves the point that Maria was making. About $25 million of that really is from our integrated operations center, which we're finishing up. We're adding some facilities out there that's about a $200-plus million investment. A little bit of that carries over into the new year 2022. We've got some work on the generation side as you would imagine as everyone would have maintenance CapEx there. And then, we're investing a great deal in technology. That's the other chunk or part of that digitization, more customer service activities, improved work into -- flow, and how we manage massive amounts of data that we're collecting. Some of our systems are older, need to be replaced, operating systems, administrative systems, and what have you. So -- and then as you look to the out years 2023 and 2025, again those exclude as does anything in '22 for generation that we may build. It's largely grid-related work. You could really see the technology investments continuing, the $85 million, but then it's close to $400 million in all of the topics that Maria just mentioned. So it's really about grid and resiliency other than any generation, which is not included here.

Travis Miller
Okay. Great. That's helpful. One higher-level question. Obviously, you've talked about a lot of capacity needs relative to energy needs, how do you think about capacity in a 80% carbon reduction world or even 100% clean energy world these days? We typically think about capacity as a fossil fuel source type of resource. How do you...

Maria MacGregor Pope
So we're -- we start out blessed to be in the Pacific Northwest where overall hydro generation makes up about 50%, 55% of the generation in the region. So I think it's important to acknowledge that we have a natural competitive advantage from that standpoint and much of that in addition is low cost. We also do have capacity factor from both wind and solar, and the diversity of being able to use those combined and then adding battery storage. And our Wheatridge facility is a great example of not only that since it combines all three of those technologies and at scale, but it also better utilizes a very scarce resource of transmission. So that's important. I would also say I'd mentioned about being able to use the distribution system as a shock absorber and really a source of capacity across our area. And that will grow very rapidly, and it is a really important component for us. I would also say that we have a number of partnerships. We've announced a **partnership** with **Douglas PUD**, one of the hydro operators on the midsea. **We provide energy** services, **they provide capacity** to us. And you can see a renewal of a contract we have with the Confederated Tribes of Warm Springs along those same lines on the Deschutes River as well as many others. We take, what I would call, an all-and-above set of solutions including all of the integrated aspects of West wide markets and the need to move much faster and accelerate the pace of change across the entire West. So it's an exciting time. These are challenging problems. I don't want to underestimate or sound like we have all the answers, we're going to be learning and growing through this with every year. And it really is going to be the challenge of the next decade around reliable sources of capacity that supports ever-increasing uses of electricity, and we're excited to be leading in this clean energy future.

James A. Ajello
Yes, Travis, I'll just wind up here by saying that in the 2021 RFP that we're talking about launching here in the near term, about 375 megawatts of non-emitting capacity is being called for. And I'm going to be very interested to see how battery technology and the cost curves show up in terms of that auction. I can't pre-judge it right now, but that's a pretty big purchase for a system of this size. So we'll see where that goes. And it may not only be batteries. But the sense we have from the market is that they will show up. And of course, pricing will be very, very important.

Operator
Our next question comes from the line of Andrew Levi from HITE Hedge.

Andrew Levi
A couple of questions. First on kind of what's going on in Congress and Direct Pay, I assume you guys are kind of familiar with that and looked at that. Is that correct?

James A. Ajello
Yes.

Maria MacGregor Pope
Yes.

Andrew Levi
Okay. Before I ask my question. So how does that kind of play in, so assuming you win a portion of this capacity that's needed? I guess that's both good for you guys and for the rate payers, it brings in more cash immediately, it maybe affects rate base a little bit as well. But if what you're saying is a situation where you may need to issue some equity eventually to pay for these capacity additions, how would that kind of offset that equity need and maybe change your outlook as far as growth? And then additionally, I would think it would also make you more competitive as a bidder for these assets too by being able to use something like that in your calculations?

Maria MacGregor Pope
So Andy, first of all, thank you for the question. And you're absolutely right. Our ability to deploy all of the tools that we have whether it be tax equity, whether it be through PTCs, ITCs, Direct Pay, grants from Department of Energy, as I mentioned we received a grant for some projects in our distribution system targeting low-income areas, all of these things are incredibly important tools as we deliver cost-effective, renewable and reliable energy to our customers. What we call here is leveling the playing field, but it's really important that customers do not see price shocks and that we're able to use all of these tools competitively and effectively for our service territory, the state of Oregon, and all the customers that we serve. There's no question that Direct Pay would offset needs for equity and give us more optionality as we move forward. As with many other aspects in the reconciliation plan as well as all of the tax issues still being worked out.

James A. Ajello
I'm a fan of the **Direct Pay PTC**, Andy, because -- well, I think it's probably pretty obvious, but it's a significant gain for our customers, a significant gain for the company. The thing that I would add to Maria's explanation is that this could help us eliminate some of the unutilized credits that we have carrying forward, right. So you'd have more efficiency in that regard as well. So the cash benefits, the cash flow, the lack or the lessened equity requirements are all benefits. And I hope we get that just to be honest.

Andrew Levi
Okay. And then kind of continuing on, then you have this like regulatory -- structural regulatory lag. That's a fairly fixed cost if I'm not mistaken, it doesn't really grow a lot as far as the actual cost of the lag. So as your rate base grows by definition that lag -- especially if you end up adding significant capacity in CapEx, that lag theoretically should shrink, shouldn't it?

James A. Ajello
Yes. Absolutely right. And yet another reason why we're benefiting from the growth in our territory. That sort of growth should benefit us in a number of ways including that lag, right. We -- as you know I mean, the **OPUC calculates our equity returns differently than we would** from an accounting standpoint. We punch over 9% on an accounting standpoint. So we do relatively well I think with investors. In terms of the allowed ROE, of course, they take out the short-term debt here. So we actually have a bit higher ratio on equity as calculated by OPUC standards than we would on an accounting basis, but our returns are better on an accounting basis there. But you're right, we're -- it's the concept of spreading those expenses over a larger base that's fundamentally right.

Maria MacGregor Pope
It also reduces the volatilites. You have a larger, more stable base to start with.

Andrew Levi
Got it. And one last question. So this is kind of circling back to the beginning. So just on the PCAM. So this -- your strategy as far as kind of eliminating that risk for both the shareholder and for the rate payer by adding this capacity over time and whether it's -- whether you own it or you contract for it, that obviously will help on the volatility especially if we get extreme weather. But I'm just curious just for 2023 -- 2022, excuse me, I'm jumping ahead. Every year matters to me as I get older, so I should take my time here. I guess for all of us, but for 2022, again without divulging anything that you may not want to divulge as far as how you're going to go into the market, what's kind of the strategy as far as trying to eliminate -- if we got extreme weather again, we don't know what the weather's going to be, but to try to will eliminate some of that volatility into next year for both of you, the shareholder and the company?

Maria MacGregor Pope
Yes. Well, so first of all, we take a -- what I call sort of an all-and-above set of strategies. And really, it starts with how we run our generation facilities and ensuring that they are 100% reliable during the most challenging days of the year. The next is how we integrate those generation

facilities across our power operations area, and ensuring that we have the right amount of capacity procured and the right reserve margins for the increased volatility that we are seeing as we move forward. And clearly, all of those things we've taken actions on. We also have adjusted and worked with parties and commissioned our modeling techniques to make sure that our modeling is reflecting the current market reality of having less, quite frankly, thermal resources that can just be turned on and off. And so, those things are really important. As we look further out, I -- better integration of renewables into our distribution system. And so, we have accelerated in '20 -- starting now and through 2022 and 2023, our distributed resource plan. And that's really important to be able to use the distribution system essentially as a circuit breaker and a source of generation. And we found that this was particularly helpful during the high heat dome events where we were able to move around some of our distributed resources in the system as well as manage transformer outages and others, and really manage more reliability at that time. And then finally, working with all of our utilities across the West to ensure that we're working on day-ahead markets, we're working on further integration and other areas around reliability, and then finally, looking at all the way down to assessing RTOs and other mechanisms that will help us move forward. So we're taking a layered approach starting with ourselves and corrective actions we can do, things that we can do that are new and different using technology, and then things that we can deal with through partnerships and others. So I hope that this is really important work and it is unique work of a regulated utility, and we're fortunate to be vertically integrated and to be able to serve our customers. There's no question that our customers want ever-increasing amounts of clean energy, but they're not going to trade-off cost and reliability.

James A. Ajello
Andy, we learned a lot this summer from the extreme conditions that we found ourselves in. Our system worked very well, generation as well as the T&D system, very limited impacts on the customer. So I think we were battle-tested in that regard. But at the same time, those more extreme conditions, I think someone said it earlier on the call, are those the new normal or not. And we don't know. But -- and I won't say much more than this. We've already prepared very well for next summer in terms of our positioning and I think we're going to be extremely well prepared as we go into the season next year.

Andrew Levi
Got it. That's terrific. And yes, I think the main thing is you kept the lights on, which is the most important thing.

James A. Ajello
Yes. I was very proud of the group, both on the generation side and the T&D side under extreme -- very extreme conditions.

Maria MacGregor Pope
In each point in time, whether it be fires or ice storms or heat domes or whatnot, we are rapidly iterating and learning faster than we ever have before.

Operator
Our next question comes from the line Brian Russo from Sidoti.

Brian J. Russo
Just curious when you said to AUT and the net variable power costs, do you assume normal hydro condition? Or do you utilize a forecast when setting that? And when is the actual date in which the AUT is set?

Maria MacGregor Pope
So we use a long-standing hydro forecast. And sometimes we're a little bit above them, sometimes we're below them. Those hydro forecasts go back decades. And believe it or not, but in the early part of the 30s and 40s and I have to go back and look at that exact date, we had tremendous droughts across the West. So that data is actually reflected in the hydro forecast as well. And then for the wind forecast, which is just as important, we use 5-year rolling averages. And we've had pretty top wind conditions as well. So that's reflected in the history that's used. All of that data also goes into how the market is pricing, both electricity and gas. And that -- those prices are trued up. And that we will -- in the next couple of days and weeks, we will be setting the AUT and then that will be what we'll use for 2022. Combined with the new modelings that we've worked together on with the parties.

Brian J. Russo
Right because I know that the forecast are for wet and cold weather in the Pacific Northwest and I was wondering if that's captured in the tariff or if that creates the benefit that you potentially retain under the fee camp?

Maria MacGregor Pope
So the current weather conditions or the current forecast is not necessarily used in how we are setting. We use -- it goes into the calculations of the longer-term or in the case with 5-year averages. And I can tell you, we -- if we are expecting a full year of wet and cold weather, we're off to a good start in that instance. And that will be very helpful for hydro conditions as well as restocking not only reservoirs but also in some instances the water table. So all of that is good and will be a benefit this next year. I would also note that with those wet and cold temperatures also comes a lot of wind that not only helps with energy generation but can create additional outages. And so, that sometimes is a negative hit to our T&D cost. So we can see weather go both ways. And we are -- it's one of the reasons that we're hardening our system so that we can reduce outages, especially as people continue to work at home and kids are sometimes going to school still in home, making sure that our reliability is higher than ever.

Brian J. Russo
Understood. And then just real quickly on EV infrastructure. Is that a sizable investment opportunity in addition to owning, building, or owning more supply for your portfolio?

Maria MacGregor Pope

Sure. So first of all, from a legislative enabling standpoint, we've got great decisions on the books in support of utility infrastructure to accelerate the pace of **electric vehicle** adoption whether it is infrastructure that's needed within our systems, transformers, substations, lines, whether it is make-ready, so the additional cabling and infrastructure to get to the charging stations or whether it's the charging stations themselves. It's very clear that the State of Oregon and the Commission expect the Portland General to be a leader and an enabler in clean transportation. And so, we see it as a tremendous opportunity. It will -- obviously smaller skies now but we'll increase substantially with each year. And the forecast for electric vehicles are very high, and Oregon has some of the highest penetration, highest amounts of electric vehicles already to start with. But I -- the other is that the more electric vehicles there are, the more sort of off-peak periods of charging we can do, which enhances reliability, lowers cost for customers overall. And so, we see it as really a synergistic sort of goodness for the entire system as we move forward. Not only is it a cleaner environment, better reliability, but also we're able to lower costs as electricity as a fuel is less expensive than fossil fields.

James A. Ajello
Right. It will show up in load growth, I would say, tending in the second half of the decade here, but starting to ascend in the next couple of years in addition to the **CapEx implication**. So I think there's goodness on both sides. There'll be additional CapEx to support, as Maria said, but also I would estimate more and more load growth coming out of that as we get to the second half of the decade.

Maria MacGregor Pope
We see each electric vehicle essentially equivalent to a new residential customer.

Operator
Our final question for today comes from the line of Paul Patterson from Glenrock Associates.

Paul Patterson
And so listen, so much of my questions have been answered. Just I really appreciate your comments, Maria, about your focus on customer costs, et cetera and I was just a little surprised, and maybe you can sort of explain if you can, the disconnect in the staff testimony, which seems to highlight right upfront if they're concerned that there is some sort of trade-off between this and an environmental focus? At least that they seem to be somewhat concerned about that. And I'm just wondering if you could sort of explain where you think they might be coming from or if this is a communications issue or what do you think? Because I know you guys are just the opposite or at least that's my impression so?

Maria MacGregor Pope
So first of all, I don't think I'm going to take a stab at where staff's coming from. I would reiterate all the comments that Jim has made that we work collaboratively together. They're the regulators. We're the regulated. We, as a company, are really proud of the investments we have made. I believe we got it right in terms of seeing the future and the increased volatility, the pressure around reliability, and we have been investing to be able to weather the storms that

come at us, whether it's high heat or ice or whatnot and to be able to deliver affordable, reliable energy to our customers that is increasingly carbon-free. And if you look at the overall price increases that we have proposed, they're quite modest, and it's -- really hats off to everyone who works at Portland General day in and day out at driving efficiency across our system, better use of technology on digital solutions, putting the customer first in everything that we do. And I'm really proud that we were able to keep our customer prices as low as we've proposed in the general rate case and that we were able to hold off on our rate case during the worst days of the pandemic. So I think there's a lot of goodness between our filing, and we look forward to working collaboratively with parties as we move forward.

Paul Patterson
Sure. But sort of outside the context of the rate case itself and the back and forth and what have you on that, is there sort of -- when you guys are making -- you guys are forward-thinking and you're looking at all this, are there ways perhaps of using technology and renewables to actually lower cost for customers? Or I mean, do you see any of these things as perhaps being from a -- sort of a cost reduction perspective perhaps in terms of delivering this? I mean, in other words, it seems to me from reading is that they felt that there was some sort of trade off at least in terms of focus. And that's why I was sort of just wondering, strategically speaking, just in general how should we think of that when you're looking at all this? Or is it just, look, if we're going to be going green, we're going to have to pay a lot more for it. Do you follow what I'm saying?

Maria MacGregor Pope
No, I don't believe we're going to have to pay a lot more for it. But I do think we're going to need to be smarter. We're going to need to use technology in different ways. We're going to need to be integrated with partners, not only in our distribution system, many of whom are our customers, but also across the West. And you can see that continually through the work that we have done to keep our costs low. Renewable energy today -- new renewable energy, in most instances, costs less than new thermal operations, but it's going to create additional challenges around technology. I'm really pleased that we've gotten after our distributed resource systems, we have an ADMS system that's just about to go live. And we will continue focusing in on the technologies that will allow us to reduce costs for customers and the renewable energy that we are taking on. This is a huge transition, and we're all learning together, and we're going to be transparent and collaborative.

Operator
This does conclude the question-and-answer session of today's program. I'd like to hand the program back to Maria Pope for any further remarks.

Maria MacGregor Pope
Great. Thank you all for joining us today, and for those of us that we will see at the EEI Financial Conference in just a couple of weeks or 10 days. We appreciate your interest in Portland General, and we hope to connect with you in the future. Thank you.

Operator

Thank you, ladies and gentlemen, for your participation in today's conference. This does conclude the program. You may now disconnect. Good day.

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Attachment 3

https://www.wsj.com/articles/accounting-rules-for-energy-tax-credits-divide-utilities-solar-producers-11620404888

CFO JOURNAL

Accounting Rules for Energy Tax Credits Divide Utilities, Solar Producers

Some utilities, including Duke Energy Corp., say changing normalization rules could spur more investments in clean energy

Some utilities say rules about how to account for clean energy tax credits curb investment in renewable power.

PHOTO: TOM WILLIAMS/ZUMA PRESS

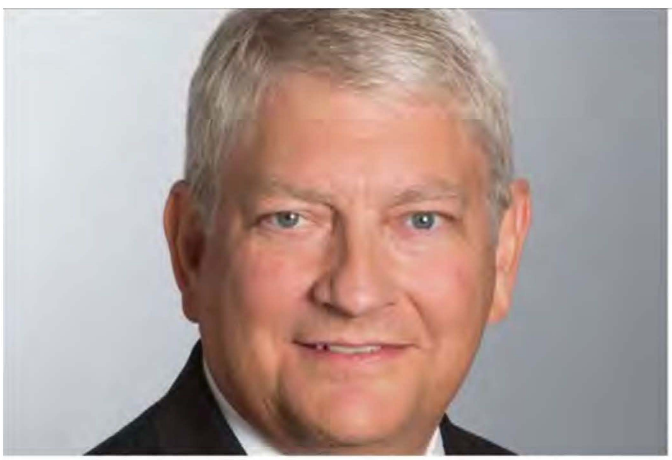
By Kristin Broughton
May 7, 2021 12:28 pm ET

A bill in Congress to boost investments in renewable energy is exposing a rift between some utilities and solar energy companies over changes it would make to decades-old accounting rules.

At issue is how utilities account for clean energy tax credits, a component of the Biden administration's push for green power. The legislation, which was introduced by Senate Democrats, would consolidate credits for renewable energy and apply them across a wider range of technologies. It would also give utilities an opportunity to avoid an accounting requirement known as normalization that forces them to pass along tax savings to customers over time to keep rates steady.

Under current normalization rules, utilities must spread out the value of certain tax benefits, including credits for so ar en rgy investments, over the life of an asset—for example, a power plant. The Senate bill would let them opt out of normalization for certain investments in energy transmission or storage if a state commission agrees, a move aimed at encouraging them to develop more renewable energy projects.

Some utilities, under pressure from investors and state governments to go green, say the current rules create a hurdle for investments in renewable power. The current solar tax credit allows companies to defray a portion of development costs. Unlike utilities, independent solar producers can immediately incorporate tax savings into their prices when they receive a credit. That means they can make better offers on state proposals to build new solar facilities, executives said.



Steve Young, CFO of Duke Energy.
PHOTO: DUKE ENERGY

Duke Energy Corp. is one of several utilities that has advocated for making changes to normalization. "We're great at building infrastructure. This is good for customers to have us in this game," said Steve Young, chief financial officer at the Charlotte, N.C.-based utility. The company, which plans to triple its renewable energy capacity by 2030, operates 35 solar plants, which are subject to normalization rules, as well as 150 plants in a separate commercial unit that sells green power to businesses and governments.

The Senate bill, sponsored by Finance Committee Chairman Ron Wyden (D-Ore.), would give companies an option to claim a production tax credit for solar energy, which isn't subject to normalization, instead of an investment tax credit, which is. The bill, known as the Clean Energy for America Act, has been introduced in previous years but hasn't become law yet. This year's Senate version of the bill is the first to include changes to normalization. Another proposa in th House doesn't include such a provision.

Xcel Energy Inc., a Minneapolis-based utility, is another that supports making changes to normalization rules. "Having the right policies in place to help us achieve this transition as [quickly] as possible is important," Brian Van Abel, the company's chief financial officer, referring to the U.S.'s shift to cleaner energy.

The Solar Energy Industries Association, which has previously opposed changes to normalization, said it plans to push for changes to the Senate bill, without giving details. "We look forward to continuing to work with the chairman and his staff on further refinement of policies that will support a competitive solar market," Erin Duncan, SEIA's vice president of congressional affairs, said.

Utilities and solar producers, which sometimes compete when bidding for production assets, also rely on each other. Utilities often buy power from independent solar producers to meet state renewable-energy targets.

"Many independent power producers basically favor normalization because it has created a market for them," David Burton, a partner at Norton Rose Fulbright US LLP, said.

The push to opt out of normalization marks a reversal of sorts for the utility sector. Utilities initially lobbied for the accounting requirement, and it has been a boon to their revenue, allowing them to pass along tax savings slowly, while keeping customer rates steady. In addition to investment tax credits, utility companies also normalize tax savings they receive when they purchase equipment and other assets.

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Allowing utilities to selectively opt out of the accounting rules for clean energy, where they face competition, while they benefit from normalization on other assets, is unfair, said Dan Nelson, vice president of tax at 8Minute Solar Energy LLC, a solar-energy producer in Los Angeles that sel s pow r to utilities in California.

“The proverbial allowing someone to have their cake and eat it too is really what that reminds me of,” Mr. Nelson said.

Write to Kristin Broughton at Kristin.Broughton@wsj.com

Appeared in the May 8, 2021, print edition as 'Tax Credits Divide Utilities, Solar Firms.'

Attachment 3

November 16, 2021

To: Curtis Dlougy
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UI 461
PGE Response to OPUC Data Request 004
Dated November 4, 2021

Request:

Please discuss any other options PGE explored besides the proposed affiliate structure to avoid ITC normalization.

Response:

In addition to the proposed affiliate structure, PGE also advocated for Federal tax policy changes, considered an unregulated affiliate held by a holding company, and tax equity options (sale leaseback and partnership flip). The proposed affiliate structure offered the best balance of competitive price to customers, complexity, and risk allocation to PGE.

December 1, 2021

To: Curtis Dlougy
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UI 461
PGE Response to OPUC Data Request 005
Dated November 17, 2021

Request:

Refer to the Company's response to Staff Information Request No. 4. Please provide all documentation to support the assertion that the proposed affiliate structure offers the "best balance of competitive prices to customers, complexity, and risk allocation to PGE" for all options explored by PGE.

Response:

Subject matter experts (SMEs) in PGE's Tax Department have held numerous informational meetings with outsides consultants and other utilities, including, but not limited to, EEI committee meetings, Entergy, Ernst & Young, KPMG, Mizuho Bank, NiSource, PricewaterhouseCoopers, Troutman Pepper, Wells Fargo, and Xcel Energy over the last several years related to Investment Tax Credits, Production Tax Credits, normalization issues, tax planning, and tax equity. Additionally, PGE tax SMEs have also independently researched relevant sections of the Internal Revenue Code, notices, and private letter rulings in regard to the normalization issue.

Based on these numerous discussions, extensive research, and the SMEs' knowledge and professional expertise, the proposed affiliate structure was the best option for achieving competitive prices for customers .