



**Portland General Electric Company**

Legal Department  
121 SW Salmon Street • 1WTC1301 • Portland, Oregon 97204  
Phone 503-464-7371 • Fax 503-464-2200  
portlandgeneral.com

January 23, 2026

***Via Electronic Filing***

Public Utility Commission of Oregon  
Attention: Filing Center  
P.O. Box 1088  
Salem, OR 97308-1088

Re: AR 674 Division 91 Rulemaking Energy Amendments

Dear Filing Center:

Portland General Electric Company (PGE) appreciates the opportunity to provide these comments in response to the Public Utility Commission of Oregon (OPUC or Commission) Notice of Proposed Rulemaking (NOPR) to adopt rules In the Matter of Small-Scale Renewable Energy Projects (SSRS) in Division 91, AR 674.

I. Executive summary

At a high level, PGE's opinion is that there are fatal flaws associated with the proposed rules that would render them invalid in judicial review<sup>1</sup> and as such the Commission should return the proposed rules to Commission Staff (Staff) for refinement consistent with the law and public policy. PGE believes that the interpretation of ORS 469A.210 now embodied in the rules is contrary to the plain meaning of the statute and likely a misinterpretation of Commission Order No. 21-464 on how to calculate aggregate electrical capacity. The rule revision inappropriately removes a generation type of resource, those generating electricity behind the meter, from the aggregate electrical capacity of the system, creating a distinction where none exists and separating some electrical capacity that is paid for through customer rates and that supports the grid from other electrical capacity that is paid for through customer rates and supports the grid. The statute makes no such distinction. The legislature, in adopting ORS 469A.210 in 2007 and in amending it significantly in 2016, sought to encourage all small renewable resources, not just those in front of the meter.

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<sup>1</sup> ORS 183.400 provides in part that a court may declare a rule invalid if it finds the rule exceeds the statutory authority of the agency or was adopted without compliance with applicable rulemaking procedures.

## II. Background

It is undeniable that adoption of and implementation of ORS 469A.210 has a contentious history going back to its original adoption, its modification in 2016,<sup>2</sup> its clarification in 2017,<sup>3</sup> and its further modification in 2021.<sup>4</sup> The original rulemaking docket which first adopted OAR 860, Division 91, was a docket that stretched over three years, contained multiple rounds of comments, issued a set of proposed rules that were never acted upon, and then sat largely moribund for two years until rising like a phoenix with a new set of proposed rules, another round of comment and a Commission order.<sup>5</sup> The legislative arena has been particularly active since 2016, with legislation proposed but not passed, to modify the statute numerous times to be more prescriptive, require greater percentage obligations, clarify Commission authority to adopt rules or forbid utility ownership of qualifying resources.<sup>6</sup>

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<sup>2</sup> Through Senate Bill 1547, the statute was modified from a generally applicable goal for utilities across the state to generate at least 8% of load from small-scale renewable energy projects as well as a direction to all state agencies, including the OPUC, to adopt policies and procedures supporting the goal, to a statute that removed the direction for state agencies to adopt policies and procedures and modifying the goal for all utilities to a mandate of 8% capacity on just the investor-owned electric utilities.

<sup>3</sup> Senate Bill 339 was adopted in 2017 to fix an issue caused by the adoption of SB 1547. SB 339 ensured that resources used to comply with ORS 469A.210's mandate were not the same as those that may be used to comply with a renewable portfolio standard, but instead were facilities that generated energy from the same sources of electricity, a small but critical difference when it comes to the current rule language requiring that projects be an "Oregon Renewable Portfolio Standard-approved generator." *Current* OAR 860-091-0030(1). This error is being corrected by the *proposed* OAR 860-091-0030(2)(a) specifying that the projects used to comply with the standard must only be of an Oregon Renewable Portfolio Standard-eligible generation *type*. (Emphasis added).

<sup>4</sup> Through House Bill 2021, the 8% mandate was increased to a 10% mandate. No other changes were made to ORS 469A.210, including modifying the types of resources that can be used to satisfy the Small-Scale Renewable Energy Project standard.

<sup>5</sup> AR 622 was opened on August 14, 2018, and culminated in an order adopted on December 15, 2021.

<sup>6</sup> After the modification from a goal to a mandate in 2016, the Oregon Legislative Assembly did not enact House Bill 2136 in 2017, a bill that would have consistently increased the requirement from 8 percent to 17 percent by 2040 and granted the Commission penalty authority. In 2019, at the request of the Renewable Energy Coalition, Community Renewable Energy Association (CREA) and the Northwest Intermountain Power Producers Coalition, House Bill 2857 was introduced to require the use of renewable energy certificates for compliance, include implementation plans, and provide rulemaking authority for the Commission; the legislature did not adopt that concept. The 2019 Oregon Legislative Assembly also did not enact House Bill 3274, a bill that would have forbidden utilities from complying with ORS 469A.210 through utility-owned facilities, required RECs for compliance and provided rulemaking authority to the Commission. In House Bill 2021, the legislature increased the percentage requirement from 8 to 10%, but legislators did not enact more robust modifications proposed in multiple other bills that session, including HB 3180 and 3391. In 2023, CREA sought to make utility compliance more difficult and expensive for customers by requesting House Bill 3524, a bill that would have prohibited utility ownership of facilities that meet the standard and, again, to clarify the Commission's rulemaking authority. And in 2025, Senate Bill 1178, a virtual copy of House Bill 3524 was introduced to meet the same end, sitting in committee on sine die. Given the large number of bills introduced and rejected by the legislature in this matter, it would appear to be clear, from the legislature's point of view on this matter, that ownership and location of the facility with respect to the meter are settled issues in favor of the broadest interpretation of the SSRS.

It was PGE's position in AR 622 that the Oregon Legislative Assembly intentionally chose not to vest the Commission with either explicit or implicit rulemaking authority regarding ORS 469A.210 and has rejected and failed to adopt multiple attempts to grant the Commission with explicit authority.<sup>7</sup> We argued then that ORS 469A.210 was fundamentally a self-executing statute that required no interpretative action on the part of any state agency, in part because the terms of the statute were clear and that if the legislature wished to change that approach, it could. The statutory schema provided no specific agency with compliance authority and did not direct rulemaking. Respectfully, PGE believes that Commission Order No. 21-464 was wrongly decided. If the Commission was correct in Order No. 21-464 that rulemaking authority in this matter flows from the sole basis of the need to adjudge prudence of utility investments or costs required by ORS 469A.005 to 469A.210, there would be by extension virtually no limit to the Commission's rulemaking, allowing it to intrude on other agencies' authority, wherever utility investments or costs were subject to a determination of prudence.<sup>8</sup> Moreover, the Commission did not adopt rules on how it would engage in an evaluation of prudence of investments or costs associated with complying with ORS 469A.005 to 469A.210, but rather rules interpreting ORS 469A.210 itself.<sup>9</sup> Regardless of establishing rules setting broad parameters of resources eligible for compliance with ORS 469A.210, the Commission may still need to adjudge prudence in the type of contested, "ad hoc"<sup>10</sup> proceeding it sought to avoid through the first rulemaking.<sup>11</sup> Further, in Order No. 21-464 the Commission cited to ORS 757.262 as support for its rulemaking authority though in neither the AR 622 NOPR – nor in the AR 674 NOPR – has the Commission relied on ORS 757.262 as the basis for adoption of the rules.<sup>12</sup>

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<sup>7</sup> In addition to the legislation specified in footnote 6, where the Legislature specifically declined to provide the Commission with explicit rulemaking authority, in amending ORS 469A.210 in House Bill 2021, the legislature failed to adopt at least 16 sets of amendments that would have clarified the Commission's authority to adopt rules.

<sup>8</sup> While PGE agrees that the Commission rulemaking authority is extensive, it is not plenary or absolute, and is bounded by ORS 756.060, which limits the rulemaking to statutes *administered* by the Commission.

<sup>9</sup> In rejecting PGE's position, the Commission provided no substantive response to PGE's or PacifiCorp's arguments in *In the Matter of Small-Scale Renewable Energy Projects*, AR 622, Public Utility Commission of Oregon, Order No. 21-464 regarding its statutory authority for rulemaking in this instance, the legislative history of the adoption of ORS 469A.210 or the modification of ORS 469A.210 provided by SB 1547 (2016).

<sup>10</sup> Order No. 21-464, at 4 ("We consider that, without the rules, we would have to decide on an ad hoc basis how to interpret elements of the standard in ORS 469A.210 to determine whether the investments the utility has made are compliance with the statute and eligible for recovery under ORS 469A.120.").

<sup>11</sup> If, for example, PGE seeks recovery of costs under an ORS 469A.120 automatic adjustment clause proceeding, subsection (3) requires that utilities seeking recovery for costs associated with complying with ORS 469A.005 to 469A.210 must be sought through a filing culminating in a written order after a contested case proceeding. See, ORS 469A.120(3) and Order No. 21-464, at 4.

<sup>12</sup> The Commission cited ORS 757.262 as a basis for its authority to adopt rules in this matter in AR 622. Order No. 21-464, at 4 ("ORS 757.262 expressly authorizes the Commission to adopt policies to encourage the development of small-scale renewable resources"). However, the Commission did not cite ORS 757.262 in its NOPR for that rulemaking, nor does it rely on that statute here, a separate procedural failure that the Commission has not remedied. ORS 183.335(2)(b)(A) and 183.400(4)(c). See also, AR 622 NOPR,

However, assuming *arguendo* that the Commission was correct regarding its rulemaking authority in AR 622, the Commission now seeks to adopt rules that plainly exceed any statutory authority provided by ORS 469A.210.<sup>13</sup> The proposed rules make manifest language from Order No. 21-464 that was not drafted into the current rules and which will discriminate against the use of all behind the meter (BTM) resources, including net energy metered resources, for compliance with ORS 469A.210. There is no statutory support for this proposal and Staff notably does not provide one in its memorandum of October 21, 2025, other than to point to Order No. 21-464, which itself did not contain a detailed statutory analysis. Unfortunately, instead of seeking a path in this rulemaking that would potentially remove barriers to utility compliance with the plain language of the statute or a path that provided future flexibility,<sup>14</sup> thereby avoiding strictures that will only serve to increase the costs of compliance – and ultimately the cost to customers for utility compliance – the rules exclude BTM resources over the objections of multiple stakeholders.<sup>15</sup> This will have the direct effect of raising costs to customers as PGE complies twice with statutory requirements.<sup>16</sup>

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<https://edocs.puc.state.or.us/efdocs/HCB/ar622hcb10616.pdf> and AR 674 NOPR  
<https://edocs.puc.state.or.us/efdocs/HCB/ar674hcb341872045.pdf>.

The NOPR in AR 674 provides that the statutory authority that the Commission relies on in this rulemaking are ORS 756.060, 469A.200 and 469A.210. The NOPR in AR 674 also provides that the Commission has relied on Order No. 21-464 (AR 622) and 25-232, as well as materials and stakeholder comments submitted in AR 674. In that regard, PGE incorporates by reference in these formal comments our comments that PGE made in AR 622, including written comments filed September 28, 2018, November 29, 2018, and November 5, 2021, as well as comments made to the Commission in the instant docket dated September 11, 2025, and October 13, 2025. PGE has provided these comments, as directed by ALJ Brent Coleman during the rulemaking hearing on January 13, 2026, as attachments to these comments.

<sup>13</sup> In comments submitted in AR 622 on September 28, 2018, PGE raised the concern that a rulemaking would eventually prescribe additional terms that are not interpretive, but additive. We believe that this prognostication has now come to pass.

<sup>14</sup> In PGE's Final Comments on Staff's Proposed Amendments, October 13, 2025, we asked that, at a minimum, the rules not harm current or future opportunities to leverage and value a whole class of distributed energy resources. And that a better approach would have been to codify the Commission's flexible approach of allowing utilities to make a showing regarding BTM resources and provide criteria for making such a showing.

<sup>15</sup> In PGE's October 13, 2025, comments we stated that while we disagreed with Order No. 21-464's interpretation regarding qualification of BTM resources, we asked that Staff take a "do no harm" approach and codify the Commission's suggestion that BTM resources could count and to provide criteria for how a showing or demonstration of eligibility of BTM resources might occur. Staff declined to follow this path stating that "Nothing . . . will prevent PGE from proposing its rationale to the Commission in the future, such as in a petition for a change to the Division 091 rules." Which, while true, still codifies the prohibition and puts the final decision in the hands of a future Commission under which such a request might be denied. In the informal round of this process, the Alliance of Western Energy Consumers and PacifiCorp also objected to formally excluding BTM resources.

<sup>16</sup> PGE provided in comments that at least 358MW of net metered facilities exist on system. Staff estimated that PGE's SSR capacity deficit is between 211-238MW. See Staff Memorandum at page 4. This number assumes acquisition of 155MW of CBRE. Exclusion of BTM therefore would require PGE acquire resources to fill that deficit at a direct cost to customers.

There is perhaps a policy basis for the exclusion of the use of BTM resources for compliance with ORS 469A.210, but there is no legal one.<sup>17</sup> The determination to remove BTM resources in the AR 622 rulemaking occurred not through statutory direction and interpreting an inexact term or crafting a definition of a delegative term<sup>18</sup>, but instead by eschewing addressing the underlying regulatory issue and redirecting the determination around the use of BTM resources into a planning/policy exercise .

Which is to say that the legislature was clear in what were the elements of compliance – less than 20MW and electricity generated from a renewable resource<sup>19</sup> – but the Commission turned to the planning process to state that certain small-scale renewable energy projects are not “considered part of the utility’s resource portfolio. Rather, net-metered they are generally viewed as customer-owned resources reducing the utility’s capacity needs, rather than a utility’s resource for meeting load.”<sup>20</sup> That statement inserted the planning process into a statute that never contemplated it. Unfortunately, it also allowed the compounding error now made manifest in this rulemaking: that excluding BTM was “merely making the Commission’s previous determination on the issue explicit in the rules.”<sup>21</sup> This is wrong on at least two accounts: first, the Commission’s statement was limited to net metered systems, but the proposed rules bar all BTM generating resources<sup>22</sup>; and second, it ignores the policy direction specified by the Commission, and acted on in numerous dockets since, that specified that it was willing to revisit its determination on the basis of things that have come to pass – namely whether utilities have evolved their planning and procurement processes.<sup>23</sup> Staff disagreed with PGE’s comments in the informal round, stating simply that it did “not believe it warrants additional consideration as part of this rulemaking.”<sup>24</sup>

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<sup>17</sup> PGE uses the term BTM throughout these comments to include Net Energy Metered resources. The Staff Memorandum for AR 674 provides that “while the Commission’s Order referred specifically to net-metered projects, its justification for their ineligibility was based on the fact that these projects exist behind the meter.” Staff Memorandum for AR 674 at page 12.

<sup>18</sup> *Coos Waterkeeper v. Port of Coos Bay Oregon*, 363 Or. 354, 360, 423 P3d 60 (2018).

<sup>19</sup> ORS 469A.210(2)(a).

<sup>20</sup> OPUC Order No. 21-464, at page 13. A position that is contrary to the Commission’s finding only a few pages earlier when it stated that “capacity” for purposes of “aggregate electrical capacity,” “is plainly a term that refers to resources, not load.”

<sup>21</sup> Staff Memorandum, at 14.

<sup>22</sup> BTM resources can include not just solar PV, the most frequently net metered resource, but small-scale hydro, and wastewater digester gas. BTM resources can also include projects that are not net metered.

<sup>23</sup> Order No. 21-464, at 13, states that “we are willing to revisit this determination upon a demonstration that this paradigm has changed . . . [o]ne potentially relevant change would be a showing that the utilities are more actively accounting for and tracking larger commercial net metered projects; another could be utility planning and procurement processes that explicitly plan to increase supply from and actively solicit net metered projects.”

<sup>24</sup> Staff Memorandum, at 14.

### III. Argument

a. The rules incorrectly characterize the role of BTM resources in a utility system vis a vis ORS 469A.210 compliance

As noted, the Commission in Order No. 21-464 drew a distinction where there was none, stating that because BTM resources net generation against customer usage, that BTM resources were “not reasonably considered part of the utility’s ‘aggregate electrical capacity.’”<sup>25</sup> In the case of net metered resources the “netting” is not a physical one, but an administrative one, allowed through a net billing period over the entire year.<sup>26</sup> Crucially, Net Metering is a policy and a program, not an operational or planning reality, the NEM designation is not a resource in itself net metering encompasses a variety of technologies beyond solar. Net metering does not reflect what is going on a daily, hourly, or even minute by minute, basis with the electricity that is generated by the net metered nameplate capacity. That generated electricity is flowing, to the customer, to the grid, to other customers nearby. Indeed, the net metering statute itself recognizes that physical flow to other customers in the definition of net metering, describing “the electricity generated by a customer-generator and *fed back to the electric utility*”<sup>27</sup>(emphasis added). The Commission’s net metering rules recognize that the net metered systems support the grid, stating that if, during a billing period “a customer-generator *supplies to the public utility* more electricity than the public utility supplies the customer generator” then a credit is generated.<sup>28</sup> (emphasis added)

We know that solar customer-generators can and do size their systems to take advantage of the excess generation during the high summer months to credit their accounts while “borrowing” that generation in the winter when the sunlight is at a minimum. This approach is encouraged by the Commission’s administrative rules that end the annual billing cycle at the end the March billing month of each year.<sup>29</sup> Thus, it is well known that not only do net metered systems contribute energy and capacity to the grid supporting the customer generator and others, state policy actually encourages them to do so by sizing the systems to financially benefit from sending energy to the grid. This is the type of activity, the production of energy to support the grid, that the SSRs was meant to support.

Earlier in the AR 622 order, the Commission correctly noted that “capacity” for purposes of “aggregate electrical capacity”, “is plainly a term that refers to resources, not load.”<sup>30</sup> PGE agrees. The Commission also adopted Staff’s proposal in AR 622 to use nameplate capacity in calculation of both the numerator and denominator, stating that such an interpretation was the

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<sup>25</sup> Order No. 21-464, at 13.

<sup>26</sup> See ORS 757.300(1)(b) and OAR 860-039-0055(1) and 860-039-0060.

<sup>27</sup> ORS 757.300(1)(b).

<sup>28</sup> OAR 860-039-0055(1).

<sup>29</sup> OAR 860-039-0055(2).

<sup>30</sup> Order No. 21-464, at 8.

most consistent with the statutory language and provided for symmetry.<sup>31</sup> The Commission also reasoned that it was the “nameplate capacity of resources *servicing Oregon customers*” that mattered.<sup>32</sup> (emphasis added). As noted above, BTM resources plainly serve Oregon customers when they send energy to the grid, and BTM resources regularly send energy to the grid. Customer-sited rooftop solar generation contributed approximately 264,826 MWh of non-emitting energy in PGE service territory in 2024. Because of this physical reality, distribution planners must plan for an investment in distribution infrastructure to manage rooftop solar and other forms of behind the meter generation. Additionally, PGE’s resource planning section keeps quarterly tabs on BTM resource growth in an effort to forecast and understand how to plan the system, knowing that some capacity is accounted for through customer sited resources.

It should be irrelevant, therefore, for purposes of compliance with ORS 469A.210, whether the utility, for purposes of planning, considers the BTM resources as load reduction or as a supply resource. It can be and is both, and the statute does not direct us to make that distinction. It should be irrelevant whether BTM resources may administratively net against customer energy usage because we know that physically, they do not. The statute, ORS 469A.210, states merely that the aggregate electrical capacity “must be composed of electricity generated” by renewable resources less than 20MW in size.<sup>33</sup> Staff states multiple times that the standard is a generating standard.<sup>34</sup> The Commission agrees that the standard is a generating standard.<sup>35</sup> BTM resources generate energy that serves the grid broadly, supporting load far beyond the individual generator’s meter. This multifaceted support is not just a physical fact; it was the original policy basis for establishing the net metering framework. Given that these resources actively generate electricity to meet system demand, they clearly satisfy the requirements of the standard.

b. Order No. 21-464 provided for flexibility that the rules inappropriately ignore.

Order No. 21-464 provided for an exclusion of net-metered projects from the reasonable calculation of the utility’s aggregate electrical capacity.<sup>36</sup> But, as discussed above, the order provided for the inclusion of net metered facilities should the utility show that utility planning

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<sup>31</sup> *Id.* at 7, 8.

<sup>32</sup> *Id.* at 8.

<sup>33</sup> Order No. 21-464, at 9-10 (“For projects eligible under subsection (2)(a), *the statute contains no other qualifications.*”).

<sup>34</sup> Staff Memorandum, at 4 (“Continue to treat the SSR standard as a generating capacity standard”), 7 (excluding storage “is consistent with the application of ORS 469A.210 as a generating capacity standard”) and 11 (it is “the total nameplate capacity of an electric company’s generation resources used to serve Oregon load.”)

<sup>35</sup> Order No. 21-464, at 12 (“The primary requirement for determining the eligibility of renewable energy projects to be used by a utility for compliance is that the project must be a generator whose energy could be used to comply with Oregon’s RPS.”)

<sup>36</sup> Order No. 21-464, at 13. PGE notes that the rules that were adopted as part of the order have no language excluding net-metered projects from the calculation. Under the current OAR 860-091-0020, “aggregate electrical capacity” is only the total nameplate capacity used to serve load.

has evolved, through more active tracking and accounting or active solicitations of net metered projects.<sup>37</sup> During the informal rounds of comments in this docket, PGE diligently explained the types of actions that have occurred since AR 622 in 2021, the more active role of BTM in resource planning and the active solicitation of Community Based Renewable Energy projects.<sup>38</sup> Staff chose not to consider these changes and advancements stating simply that the “Commission’s position on net-metered resources was clearly stated in Order 21-464, and Staff does not believe it warrants additional consideration as part of this rulemaking.”<sup>39</sup> There was no explanation or detail provided as to how Staff arrived at that conclusion.

The depth of understanding of the challenges and requirements for SSR policy implementation have evolved significantly from what was known during the original SSR rulemaking.<sup>40</sup> And PGE has worked in significant fashion over the last four years to improve planning for BTMs, especially through existing processes like the Distribution System Plan and the IRP/CEP.<sup>41</sup> PGE’s reference case net load forecast includes passive BTM resources, including rooftop solar, transportation and building electrification. Distributed generation resources are captured in PGE’s corporate load forecasting and embedded in all transmission planning models. Section 5.2 of PGE’s 2023 IRP/CEP Update discusses distributed energy resources. Information about passive distributed energy resources are included in subsection 5.2.1.<sup>42</sup> As we stated in our 2023 IRP/CEP:

PGE develops a forecast of distributed energy resource (DER) adoption and hourly load impact on a regular basis. This DER forecast provides insights on how much market-based DER adoption will impact both PGE’s bulk and distribution systems. It also informs how much cost-effective demand response can be made available to shape and shift load on the bulk system. As such, the DER forecast informs PGE’s planning processes, including its Distribution System Plan (DSP) and the IRP/CEP.

The DER forecast uses PGE’s AdopDER award-winning software to model the adoption of over 60 DER technologies and technology combinations. The software uses a current, point-in-time snapshot of data from PGE systems that describes the characteristics of each PGE service point: building type and vintage, heating and cooling system, vehicle weight class(es) and fuel(s), and interconnected solar PV and storage. AdopDER also

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<sup>37</sup> *Id.*

<sup>38</sup> PGE’s Response to Staff’s Straw Proposal, September 11, 2025, at 5-6.

<sup>39</sup> Staff Memorandum, at 14 (“Staff’s view that the way in which utilities approach to behind-the-meter resources has not meaningfully changed since” Order No. 21-464).

<sup>40</sup> *In the Matter of PacifiCorp, dba Pacific Power*, Petition for Declaratory Ruling on Small-scale renewable issues, DR 58, Public Utility Commission of Oregon, Order 25-232, Appendix A, at 7.

<sup>41</sup> While dockets discussing Distribution System Planning and the order adopting the DSP guidelines were known at the time AR 622 adopted the current rules, the Commission had not accepted a PGE DSP plan until several months later in Order No. 22-083. PGE has since submitted its 2024 DSP. *See* UM 2197.

<sup>42</sup> The 2023 IRP Update reflected 668 MW of distributed solar resources in the preferred portfolio by 2030.

accounts for customer growth across PGE's service territory to simulate the eligibility, adoption, and load impacts for each DER over a 20- year forecast horizon through calendar year 2044.

From this starting point, AdopDER simulates both the market adoption of passive DERs and expected customer participation in current and future demand response programs—representing achievable potential within a potential study framework.<sup>43</sup>

AdopDER is a dynamic tool, and its outputs are sensitive to underlying assumptions—such as changes in federal and state policy, economic conditions, and regional adoption patterns. These inputs are continually refined as new data becomes available.

Customer-sited resources, including rooftop solar, batteries and standby generation play an increasingly critical role in our resource portfolio. We manage the output of our own power plants in conjunction with available power supplies on the wholesale market to deliver power to customers at the lowest possible price. We actively coordinate with transmission providers like the Bonneville Power Administration and other utilities and energy suppliers across the region, to secure transmission access and additional power on contract for customers. We also own major transmission rights to the Pacific Intertie and participate in the California Independent System Operator's (CAISO) Energy Imbalance Market (EIM) and the soon-to-be established Extended Day-Ahead Market (EDAM). These options provide additional flexibility to buy and sell power and to access a more diverse and increasingly clean mix of generating resources.

And finally, consistent with the Commission's specific direction,<sup>44</sup> PGE issued a request for offers (RFO) for Community-based Renewable Energy (CBRE) projects in 2025. This RFO was consistent with PGE's 2023 IRP/CEP specific interest regarding CBRE forming part of future energy supply. Generation in these CBREs can be BTM.

PGE has demonstrated that the “paradigm” the Commission referred to in Order No. 21-464 has changed. The utility is actively tracking and including BTM in our resource planning and portfolio. Our planning and procurement processes are seeking small-scale community resources. BTM resources, to the extent they were only viewed as reducing capacity needs, are now planned to help meet load. Exclusion of BTM in these rules is not “merely making the Commission's previous determination on the issue explicit in the rules,” it is ignoring the progress in system integration, the commission planning requirements like the DSP, and the understanding of the challenges and requirements in meeting the SSRS that staff agreed has

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<sup>43</sup> PGE 2023 IRP/CEP Update, section 5.2. Available here: [https://assets.ctfassets.net/416ywc1laqmd/3IXAbabyDeN4GH5CvWPrhh/2a2f708a7a394a88f5736f41ca885c9d/Chapter\\_5\\_Resource\\_options.pdf](https://assets.ctfassets.net/416ywc1laqmd/3IXAbabyDeN4GH5CvWPrhh/2a2f708a7a394a88f5736f41ca885c9d/Chapter_5_Resource_options.pdf)

<sup>44</sup> Order No. 21-464, at 13 (suggestion one indicia of improved planning processes might be “procurement processes that . . . actively solicit net metered projects.”).

actually significantly evolved, since 2021.<sup>45</sup> This progress and effort cannot simply be brushed away with a simple statement.<sup>46</sup>

- c. ORS 469A.210 must be interpreted to be more than another Public Utility Regulatory Policies Act (PURPA) requirement.

As a general rule, courts assume that the legislature did not intend any portion of its enactments to be meaningless surplusage.<sup>47</sup> That is, we can assume that the legislature, in adopting statutes would not merely adopt a requirement that already exists in a different fashion or under a different name, lest the portion of the new statute would be rendered redundant. Additionally, it is assumed that any interpretation or construction of the statute must be done in a manner that will “give effect to all.”<sup>48</sup> The legislature is also assumed to be aware of existing law, including common law and judicial decisions, when adopting new requirements.<sup>49</sup>

The proposed rule fails this test. The rule, if implemented as proposed, would fundamentally do little more than require utilities to purchase energy from otherwise PURPA eligible facilities below 20 MW in nameplate capacity. PURPA was adopted in 1978 and state statutes, ORS 758.505 to 758.555, implementing the federal law were adopted in 1983. The federal PURPA law was nearly 30 years old when ORS 469A.210 was first adopted as a goal and the state law was over 30 years old when ORS 469A.210 in its current form was adopted in 2016. It would have been easy for the legislature to specifically reference ORS 758.505 to 758.555 if it meant to limit compliance to PURPA eligible projects, but it did not.<sup>50</sup> Instead the legislature chose to use terms like “aggregate electrical capacity” and “small-scale renewable energy projects” to indicate that something different was intended.<sup>51</sup>

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<sup>45</sup> Order 25-232, Appendix A, at 7.

<sup>46</sup> Staff Memorandum, at 14 (“Staff’s view that the way in which utilities approach to behind-the-meter resources has not meaningfully changed since” Order No. 21-464).

<sup>47</sup> *State v. Clemente-Perez*, 357 Or. 745, 755, 359 P.3d 232 (2015), citing ORS 174.010 and *Arken v. City of Portland*, 351 Or. 113, 156, 263 P.3d 975 (2011) (noting “cardinal rule of statutory construction to give significance and effect to every part of a statute” and “well-established principle to avoid interpretations of statutes that render portions of them redundant.”). See also, *State v. Stamper*, 197 Or.App. 413, 418, 106 P.3d 172 (2005).

<sup>48</sup> ORS 174.010.

<sup>49</sup> See, e.g., *Montara Owners Ass’n v. La Noue Development, LLC*, 357 Or 333, 341, 353 P.3d 563 (2015) (“The context for interpreting a statute’s text includes the preexisting common law, and we presume that the legislature was aware of that existing law.”) and *Mastriano v. Bd. Of Parole & Post-Prison Supervision*, 342 Or. 684, 693, 159 P.3d 1151 (2007) (“We generally presume that the legislature enacts statutes in light of existing judicial decisions that have a direct bearing on those statutes.”).

<sup>50</sup> The legislature knows PURPA well and in 2025 adopted House Bill 3863, a bill with the title “Relating to qualifying facilities under the Public Utility Regulatory Policies Act of 1978.”

<sup>51</sup> Typically, when the legislature uses different language, especially in similar statutory provisions, courts presume that it intended the phrases to have different meanings. See, e.g., *Lindsey v. Farmers Ins. Co. of Oregon*, 170 Or.App 458, 464, 12 P.3d 571 (2000) (“When the legislature uses different language in similar statutory provisions, it is presumed to have intended different meanings.”); *Northwest Natural Gas Co. v. City of Gresham*, 359 Or. 309, 323,

With PURPA requirements already in place, the adoption of the capacity standard would have been superfluous. Utilities were already required to publish avoided cost rates and offer to purchase energy or energy and capacity from qualifying facilities. Utilities must also make good faith efforts to transmit energy produced by qualifying facilities. Because the legislature would have known of PURPA and its requirements, adoption of ORS 469A.210 would have been merely surplus to those existing requirements, rendering the enactment redundant. PGE's view is that the legislature meant the term "aggregate electrical capacity" to be expansive. One definition of "aggregate" means "the whole sum or amount: sum total" – in other words, everything, including BTM.<sup>52</sup> This is the only interpretation that does not render the portion of the statute meaningless, that gives effect to all (ORS 469A.210 and PURPA requirements), and that assumes that the legislature knew about other utility procurement requirements.

- d. The term "aggregate electrical capacity" must be read consistently with the text and context of the rest of ORS 469A.210

PGE is focused on the term "small scale renewable energy project" and not "aggregate electrical capacity" because the rule's limitation expressed in the definition of aggregate electrical capacity, if allowed, eviscerates the meaning of the small-scale renewable energy project and, as will be shown below, what the legislature intended in adopting that term in 2007. Aggregate electrical capacity also does not describe the projects that can be used to meet the 10% requirement, that condition is found later in the statute: the capacity "must be composed of electricity generated by one or both of the following sources." The legislature did not tell us directly what should be put in the denominator, but it was very clear as to what was in the numerator. The legislature told us where to look to determine what elements compose the numerator for electrical capacity, in paragraphs (a) and (b) of subsection (2) – small-scale renewable energy projects and certain biomass projects. The rule's position on aggregate electrical capacity would render a portion of the statute meaningless because it would neglect the language that *is* in the statute that describes the resources that "compose" the standard.<sup>53</sup>

Further, the limitation proposed by staff for the term "aggregate electrical capacity" flies in the face of the plain meaning of those words and the Commission's decision in Order 21-464. As noted above, "aggregate" should mean the sum total – everything. It is difficult to understand a definition that proposes to include everything by excluding some things. The Commission found that in determining what "electrical capacity" meant, that "nameplate capacity of resources

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374 P.3d 829 (2016) ("If the legislature uses different terms in related statutes, it likely intended them to have different meanings."). Here, the legislature was directing acquisition of small energy production facilities, something supported by ORS 758.505 to 758.555 and ORS 469A.210. These can be seen as "similar statutory provisions" or "related statutes," at least from a utility procurement frame of reference.

<sup>52</sup> <https://www.merriam-webster.com/dictionary/aggregate> def. 2.

<sup>53</sup> ORS 174.010, interpretation must give effect to all.

serving Oregon customers . . . best accords with the plain language of the statute.”<sup>54</sup> As argued above, BTM resources “serve Oregon customers” even when they only serve one customer, but especially when they export power to the grid. Thus BTM nameplate should be included in the term “electrical capacity.”

As currently constructed, the rules fail to consider the sum total of all energy resources that serve Oregon customers and load, and they fail to read the statute completely in a manner that gives effect to all the language.<sup>55</sup> The rules can give effect to all the language in the statute by considering all nameplate capacity, including BTM.

e. The term “small-scale renewable energy project” includes BTM

A further, deeper examination of term “small-scale renewable energy project” affirms PGE’s position regarding the inappropriateness of limiting “aggregate electrical capacity” through excluding BTM.

A court’s “standard of review of an agency’s interpretation of a statute depends on whether the statutory term at issue is an exact term, an inexact term, or a delegative term.”<sup>56</sup> PGE suggests that the term “small-scale renewable energy project” is an inexact term. “An inexact term often requires an agency to determine what the legislature intended by the term,” but is still a “complete expression of policy” if “less precise” than an exact term.<sup>57</sup> PGE argues that the term “small-scale renewable energy project” is an inexact term because it is not an open-ended word or phrase that requires the Commission to engage in policymaking to effectuate the legislative policy of the statute. Inexact terms can be whole phrases. A term is deemed to be “inexact” when “the legislature used the words to express a complete legislative meaning but with less precision than if it had used an exact term.”<sup>58</sup> “A statute with inexact terms may be subject to alternative plausible interpretations, but the meaning of those terms is still a question of law, *not agency prerogative.*”<sup>59</sup> (emphasis added). Examples of inexact terms include: “act in the capacity of an escrow agent,”<sup>60</sup> “could not know,”<sup>61</sup> and “successor to the business.”<sup>62</sup>

PGE suggests that the term “small-scale renewable energy project” is not an open-ended word requiring policymaking because it is further defined by two exact terms: 20 MW and renewable

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<sup>54</sup> Order No. 21-464, at 8.

<sup>55</sup> ORS 174.010, do not omit what has been inserted.

<sup>56</sup> *Coos Waterkeeper v. Port of Coos Bay Oregon*, 363 Or. 354, 423 P.3d 60 (2018).

<sup>57</sup> *PNW Metal Recycling, Inc. v. Dept of Env't Quality*, 371 Or 673, 694, 540 P.3d 523 (2023).

<sup>58</sup> *Coos Waterkeeper*, 363 Or. at 360.

<sup>59</sup> *PNW Metal Recycling, Inc.*, 371 Or 696.

<sup>60</sup> *Coast Security Mortgage Corp. v. Real Estate Agency*, 331 Or 348, 354, 15 P.3d 29 (2000).

<sup>61</sup> *Oregon Occupational Safety & Health Div. v. CBI Servs., Inc.*, 356 Or 577, 589, 341 P.3d 701 (2014)

<sup>62</sup> *Blachana, LLC v. Bureau of Lab. & Indus.*, 354 Or 676, 687, 318 P.3d 735 (2014)

source as defined in ORS 469A.025.<sup>63</sup> Further, there is no level of policymaking from the Commission necessary to provide meaning to the term within the context of the statute. Similar to “act in the capacity of an escrow agent” or “successor to the business,” the term may be capable of more than one meaning, but the Commission is still required to interpret the term in accordance with the legislative policy expressed in the statute as a whole. The rule’s interpretation excluding BTM is inconsistent with the stated purpose of the Oregon Renewable Energy Act and subsection (1) of the statute.

Because the term “small scale renewable energy project” is an inexact term, a court would review the term, without deference to the Commission’s interpretation, under the application of the methodology articulated in *State v. Gaines*.<sup>64</sup> That is first, the text and context; second, the context of the term in the larger statutory scheme; and then finally, legislative history.<sup>65</sup>

Looking at the text and context of the term<sup>66</sup> “small-scale renewable energy project” we can see that it is immediately conditioned by the description of 20MW or less and the type of energy used. PGE has not found any prior judicial construction of the term in Oregon case law. As for a plain meaning interpretation, it is clear that regardless of the location of a revenue meter, BTM resources can be “small-scale renewable energy projects” just as easily as front of meter ones can.

Moving to context, which includes other provisions in the same statute and other related statutes, we find additional support for PGE’s reading. The Oregon Renewable Energy Act,<sup>67</sup> within which ORS 469A.210 appeared and the term “small scale renewable energy project” was first used, contained “whereas clauses” including:

“Whereas the Legislative Assembly finds that it is necessary for Oregon’s electric utilities to *decrease their reliance* on fossil fuels for electricity generation and to *increase their use of renewable energy sources*; and \* \* \*

“Whereas the Oregon Renewable Energy Act provides a comprehensive renewable energy policy for Oregon, enabling industry, government, and all Oregonians to *accelerate the transition to a more reliable and more affordable energy system*.”<sup>68</sup>

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<sup>63</sup> ORS 469A.210(2)(a).

<sup>64</sup> *State v. Gaines*, 346 Or. 160, 206 P.3d 1042 (2009).

<sup>65</sup> There is no evidence that Staff, in its deliberations on this matter, reviewed the text in context or identified and considered legislative history, other than that provided by PGE. Staff Memorandum, at 13.

<sup>66</sup> “We begin with the text and context of the statute, which are the best indications of the legislature’s intent. *State v. Walker*, 356 Or. 4, 13, 333 P.3d 322 (2014).

<sup>67</sup> SB 838 (2007), sometimes mistakenly called the Renewable Portfolio Standard. The RPS was only one part of the Oregon Renewable Energy Act.

<sup>68</sup> SB 838 (2007).

As stated in these “whereas” clauses, the statute reflects the legislative policy to decrease reliance on fossil fuels, increase use of renewable energy sources, and accelerate the transition to a more reliable energy system. The statute also reflects the legislature’s understanding that having a more reliable and more affordable energy system will require a transition that is dependent on a variety of infrastructure that needs to work together in a holistic manner—in other words, a flexible approach that would comprise a mix of small-scale renewable energy projects.

Subsection (1) of the statute contains some of the original language from Senate Bill 838 and refers to a different term “community-based renewable energy projects.” It suggests that these projects are “an essential element of this state’s energy future.” Community-based projects can certainly include BTM resources, such as net metered wastewater treatment facilities or municipal buildings with solar. Further, BTM resources are, by their very nature “community-based” being located on system. They are far more “community based” vis a vis PGE, than a 20 MW solar PURPA facility in central Oregon. Certainly, PGE finds nothing in subsection (1) text that supports exclusion of BTM.

Finally, we can turn to legislative history. As stated, many times by PGE, the legislative history of this statute does not support an interpretation that discriminates against BTM resources. As adopted in 2007 as part of the Oregon Renewable Energy Act (Senate Bill 838 (2007)), ORS 469A.210 sought to promote “eight percent of Oregon’s retail electrical load [coming] from small-scale renewable energy projects with a generating capacity of 20 megawatts or less.”<sup>69</sup> Note that the term “small-scale renewable energy project” has been with us since the first adoption of the statute and thus the legislature’s intention in adopting that term must carry significant weight unless there is clear evidence from a point later in time that suggests the legislature meant something different.

As noted in the progress report from Mike McArthur, Chair of the Renewable Energy Working Group (REWG) to Governor Kulongoski, dated March 23, 2007, the “Community Caucus” of the REWG focused on community-scale renewables and policy elements that would encourage the development of a “wide diversity” of projects, and the group debated net metering policy and other policy barriers.<sup>70</sup> The REWG ultimately rejected, and did not recommend for inclusion in Senate Bill 838, the recommendation for an “Oregon version of the PURPA-type requirement that utilities must purchase power from certain qualifying facilities under standard offer contracts.”<sup>71</sup> The REWG did recommend, and the legislature did adopt, changes to the public purpose charge which provided a policy change to spur development of BTM resources,

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<sup>69</sup> Section 24, Senate Bill 839 (2007). View the original section here: <https://olis.oregonlegislature.gov/liz/2007R1/Downloads/MeasureDocument/SB838>

<sup>70</sup> Letter to Governor Kulongoski, page 2. attached as part of these comments.

<sup>71</sup> REWG Community Caucus Report, dated July 11, 2006. Attached as part of these comments.

including the incentives that the Energy Trust of Oregon provided for residential and commercial development of BTM resources.<sup>72</sup> The Status Report of the REWG of February 2007, a document that was the blueprint for the Oregon Renewable Energy Act, stated that the non-binding goal should come from “a *mix* of small scale renewable energy projects.”<sup>73</sup> All of which is important to understand that the policy basis of the original goal was to focus on a mix of small scale renewable resources while not supporting provisions that would have focused more support, in addition to PURPA, on front-of-meter QFs.

In 2016, the legislature modified the goal to a mandate. In comments provided in the informal round,<sup>74</sup> PGE showed that the testimony provided in support of the change rested generally on the notion of privately developed, smaller, decentralized and dispersed renewable projects. Some discussion was provided regarding non-utility owned facilities and some support for distributed green energy. No testimony was submitted that suggested that the legislature intended to change from its 2007 understanding of a “wide diversity” or “mix” of small-scale renewable energy projects. No testimony was provided in creating the mandate, that BTM resources should not count. And importantly, the legislature *retained* the same term for what it was seeking to support: “small-scale renewable energy projects with a generating capacity of 20 megawatts or less.”<sup>75</sup> When the legislature uses the identical phrase in related statutory provisions it is assumed that the phrase has the same meaning.<sup>76</sup> PGE suggests the same should be true here: the same term, “small-scale renewable energy project,” because it was not altered between the adoption of a goal and the modification to a mandate, would have the same meaning that the legislature understood it to have when it first adopted the goal: a wide diversity of resources and a mix of small-scale projects. The insertion of the term “aggregate” only strengthens this argument – the legislature wanted *everything*, not a limited subset.

Statements made by one legislator on the House floor 14 years after the small-scale renewable standard had been adopted as a goal and 5 years after it had been adopted as a mandate, when the only change being made was one to the percentage – from 8% to 10% -- are hardly persuasive legislative history.<sup>77</sup> Floor speeches can be an especially slim reed on which to rest any

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<sup>72</sup> Section 27, amending ORS 757.612 to extend the public purpose charge through 2025 and to limit the provision of incentives to the above-market costs of renewable energy resources smaller than 20MW.

<sup>73</sup> Status Report: REWG Debate on Oregon's Renewable Portfolio Standard, February 8, 2007, attached as part of these comments.

<sup>74</sup> PGE's Response to Staff's Straw Proposal, at 7-10.

<sup>75</sup> Compare Section 24 SB 838 “by 2025 at least eight percent of Oregon's retail electrical load comes from small-scale renewable energy projects with a generating capacity of 20MW or less” with Section 14, Senate Bill 1547 (2016) “at least eight percent of the aggregate electrical capacity of all electric companies . . . must be composed of electricity generated by one or both of the following sources: (a) small-scale renewable energy projects with a generating capacity of 20 megawatts or less.”

<sup>76</sup> See, e.g., *Mid-Century Ins. Co. v. Perkins*, 344 Or. 196, 211, 179 P.3d. 633 (2008).

<sup>77</sup> In Oregon, the most persuasive legislative history reflects consistent themes echoed throughout the legislative process. *State v. Gaines*, 346 Or. at 172, n. 9:

legislative history argument because they tend to provide a little something for everyone, especially here where the legislator was not commenting on the modifications being made by the legislation (8 to 10%), but on established law that had been adopted 5 years earlier and was not being changed (what resources might qualify) and where, as here, there is extensive legislative history regarding the purpose of ORS 469A.210.<sup>78</sup> Further, it is not the intent of one legislator that governs regarding the meaning of terms in a statute, but the intent of the legislature as a whole at the time of the bill's passage that is important.<sup>79</sup> This is because any member can make a floor speech, and there is not much usefulness in essentially stacking up the pages of each speech to compare the heights of each.<sup>80</sup> That is simply not persuasive legislative history and the Commission should reject any attempt to treat it as such.

A more appropriate place to have raised the issue would have been in committee, where the issue could have received more attention and been subject to debate. The floor statement promoted by CREA, the Renewable Energy Coalition, and the Oregon Solar + Storage Industries Association, as being dispositive of this matter,<sup>81</sup> came only during the floor debate over House Bill 2021. That bill passed through the House Energy and Environment Committee earlier in the legislative session on which the same legislator sat, but this matter was not discussed.

Thus, the rule interpretation is erroneous at the first-level textual analysis of the text, in context with the statute and other provisions of the same legislation adopting the statute. The rule interpretation is erroneous when legislative history is proffered to support a textual or contextual interpretation. And thus, the change should be rejected.

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*Justice Graber, in a dissenting opinion in Errand v. Cascade Steel Rolling Mills, Inc., 320 Or. 509, 539 n.4, 888 P.2d 544 (1995), identified only some of the pitfalls of relying too greatly on legislative history: "In general, an examination of legislative history is most useful when it is able to uncover the manifest general legislative intent behind an enactment. By contrast, an examination of legislative history is most fraught with the potential for misconstruction, misattribution of the beliefs of a single legislator or witness to the body as a whole, or abuse in the form of 'padding the record' when the views of only a small number of persons on a narrow question can be found."*

<sup>78</sup> *Brown v. SAIF Corporation*, 361 Or. 241, 271, 391 P.3d 773 (2017), discussing claimant's reliance on comments by one legislator and the court stating its reluctance to give it much weight.

<sup>79</sup> *Dep't of Consumer & Bus. Servs. V. Muliro*, 359 Or 736, 753 (2016) ("Legislative statement which represent a wider swath of legislators, not just the comments of one lone legislator, are more persuasive." And "Cherry-picked quotations of single legislators . . . have to be carefully examined.").

<sup>80</sup> *See, e.g., N.L.R.B. v. SW General, Inc.*, 580 U.S. 288, 307, 137 S.Ct. 929, 197 L.Ed.2d 263 (2017) ("[F]loor statements by individual legislators rank among the least illuminating forms of legislative history."); *Garcia v. U.S.*, 469 U.S. 70, 76, 105 S.Ct. 479, 83 L.Ed.2d 472 (1984) ("In surveying legislative history . . . We have eschewed reliance on the passing comments of one Member and casual statements from floor debates" citing *Weinberger v. Rossi*, 456 U.S. 25, 35, 102 S.Ct. 1510, 1517, 71 L.Ed.2d 715 (1982), and *United States v. O'Brien*, 391 U.S. 367, 385, 88 S.Ct. 1673, 1683, 20 L.Ed.2d 672 (1968)).

<sup>81</sup> Comments of the Small Scale Renewables Groups in OPUC Docket DR 58, pages 4-5.  
<https://edocs.puc.state.or.us/efdocs/HAC/dr58hac337670027.pdf>

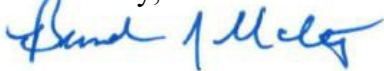
IV. Conclusion

These proposed rules will mistakenly solidify momentous changes to the structure of the small-scale renewable standard. The rules were proposed in a very time-limited, and supposedly scope limited, rulemaking where there was little discussion, research or debate into the merits of the proposal to exclude BTM resources. The rules make these changes with less than four years until the compliance date arrives, not only moving the goalposts for compliance but also raising costs for customers in doing so.

PGE does not believe the changes are consistent with the Commission authority in this matter. The changes are not consistent with the flexibility on the matter that the Commission provided in the AR 622 order. The changes are not consistent with the text and context of the statute or the legislative history. Fundamentally these changes will increase costs on customers without a comparable benefit obtained. The changes will limit opportunities to leverage and value a whole class of distributed energy resources and limit the opportunities for PGE to pair various programs with customer investments to better serve all customers. The rules will take a step backward in terms of our shared energy future in favor of one class of energy production facilities.

The rules should be rejected with directions to investigate the matters raised by PGE in these comments.

Sincerely,



Brendan J. McCarthy  
Assistant General Counsel



**Portland General Electric**  
121 SW Salmon Street • Portland, Ore. 97204  
PortlandGeneral.com

February 21, 2019

***VIA ELECTRONIC FILING***

puc.filingcenter@state.or.us

Public Utility Commission of Oregon  
201 High Street S.E., Suite 100  
PO Box 1088  
Salem, OR 97308-1088

Attn: Filing Center

**RE: AR 622 – PGE’s Final Comments on Key Policy Issues**

Portland General Electric Company (PGE) appreciates the opportunity to provide these final comments to the Public Utility Commission of Oregon (Commission) regarding the implementation of small-scale renewable energy provisions in ORS 469A.210 (2). Our comments here are supplemental to PGE’s earlier comments, including ones raising the authority of the Commission to undertake this rulemaking. We are not offering further comments on that issue.

ORS 469A.210 (2) requires electric utilities, by 2025, to meet an 8% capacity target using small-scale renewable projects and certain projects that generate electricity from biomass. We note that small-scale renewable projects may be different than the “community-based” projects that the Legislative Assembly specified in ORS 469A.210 (1). Parties at the commission hearing held on February 14, 2019, sometimes used “community-based” and “small-scale” interchangeably. They may not be the same thing. PGE believes that the 8% target applies specifically to “small-scale” and to certain biomass projects as described in ORS 469A.210 (2), not “community-based” projects specified in ORS 469A.210 (1).

On February 12, 2019, PGE submitted an updated matrix which provides a snapshot of current activity in the small-scale project queue and shows potential capacity positions for 2018, 2025, and 2036. The projects included in the numerator value demonstrate significant activity in the market through 2025, with over 110 qualifying facility (QF) projects contracting with PGE to be constructed and online by 2025. Once operational, those QFs could provide a total nameplate capacity of nearly 500 MW. While PGE has not yet obtained 8% of our aggregate capacity from small-scale projects, PGE believes that the extensive activity in the QF market shows that the goal sought by the legislature, that more small-scale renewable projects be built in Oregon, is well underway. If only a portion of the projects within our queue are built and ultimately deliver energy, PGE will meet our 8% target. We note that most of this activity has occurred in the past two years, after the adoption of Senate Bill 1547 (2016), as costs for renewable energy, mostly solar, have continued to fall.

Our comments will address the proposed rules as contained in the Notice of Proposed Rulemaking filed with the Secretary of State on December 27, 2018 and three key policy issues discussed at the Commission's rulemaking hearing on February 14, 2019:

- 1) Renewable attributes ownership
- 2) Eligibility of net metered projects
- 3) Denominator and numerator basis

### **Issue #1: Renewable attribute ownership**

The proposed rules contain complicated and problematic language regarding renewable attribute ownership, utilization of renewable energy certificates (RECs), and integration with a renewable portfolio standard (RPS). PGE is opposed to this language.

Proposed OAR 860-091-0010 provides the following definition for "renewable attributes":

"(3) "Renewable attributes" means the environmental attributes associated with energy generation represented by a renewable energy certificate that can be used to comply with Oregon's renewable portfolio standards in ORS 469A.050 and ORS 469A.055. Renewable attributes do not include greenhouse gas offsets from methane capture not associated with generation of electricity and do not include environmental attributes represented by a thermal renewable energy certificate created under ORS 469A.132."

Proposed OAR 860-091-0030 to -0050 include provisions for renewable attribute ownership requirements and further address the use of RECs associated with eligible projects for compliance with the RPS. The proposed rules require that a utility own the RECs from a project's energy generation to count the project as eligible toward the 8% capacity target in ORS 469A.210.

PGE has several concerns regarding the proposed language. As a minor point, we believe the statutory reference to ORS 469A.050 is incorrect and should be ORS 469A.052. There is no portfolio standard under ORS 469A.050.

Our first major point of concern is that the proposed rule establishes a definition of renewable attributes that is in conflict with the existing definition of REC adopted by the Oregon Department of Energy ("ODOE"). In OAR 330-160-0015 (17), the department determined that a REC is "a unique representation of the environmental, economic, and social benefits associated with the generation of electricity from renewable energy sources that produce Qualifying Electricity." In the manner established by the legislature for split authority for implementation of the Oregon Renewable Energy Act found at ORS 469A.005 to 469A.210, the proposed rule creates a conflict with the ODOE rule because it carves out certain environmental attributes from the REC where the ODOE rule includes all environmental attributes in the REC. This becomes a greater concern when the proposed rule seeks to require use of a REC to show that the utility has met the 8% target.

Secondly, the proposed rule's requirement to utilize a REC for the 8% target is inconsistent with the plain language found in ORS 469A.210. ORS 174.010 requires us "not to insert what has been omitted, or to omit what has been inserted" in the construction of statutes. There is simply no

requirement in the statute that project eligibility must be determined by renewable attribute ownership, RECs, or RPS compliance and we must not insert one.

A plain reading of the statute, subsection (2)(a), clearly defines the metes and bounds for project eligibility and they are: (1) facilities up to 20 megawatts (MW) in capacity; and (2) utilizing a *type* of energy contained in ORS 469A.025; or (3) certain biomass projects that also generate thermal energy for a secondary purpose. (emphasis ours). Project eligibility based on satisfying these requirements results in a clear and straightforward verification process. Implementation of any process for determining whether a project can help meet the 8% target under this two-pronged test is simple.

While we understand that RECs are an appealing way to provide verification, they are the wrong tool. RECs are a compliance tool to determine whether the projects utilized for RPS compliance generate qualifying electricity. The requirement of ORS 469A.210 is not to take qualifying energy from facilities – that requirement would be created by a reference to ORS 469A.020 – but instead to take energy of a *type* that can potentially generate qualifying electricity if other criteria are met, such as age of the facility. The language in ORS 469A.025 (1) is instructive, “Electricity generated utilizing the following *types* of energy may be used to comply with a renewable portfolio standard” – solar, wind, wave, geothermal, etc., can all be used.

The legislature, through ORS 469A.210, sought to promote small-scale and combined heat and power biomass energy generation. The “renewableness” of the project is determined by its type, not whether it generates a REC. The legislature did not express a preference in ORS 469A.210 about who could make claims to the environmental attributes of those projects and we should not read one into the law. Pursuant to our interpretation, the acquisition of null power from a small-scale facility could be used to meet the 8% target, acquisition of energy from a facility that declines to register to generate RECs would qualify, and a small-scale generator that was built prior to 1995, thus prohibited from generating RECs unless it is low-impact hydroelectric, would also qualify.

Thirdly, discussion in AR 622 raised uncertainty regarding the use of RECs as a means of determining if a project’s capacity is eligible to count toward the 8% capacity target. As noted above, ORS 469A.210 asks us to determine the facility capacity (i.e. instantaneous power or ability to generate) and the *type* of energy, not the amount of energy. RECs are a measure of a project’s actual energy generation and a right to claim environmental attributes, and is based on a different measurement than the statute’s criteria.

Finally, PGE has concerns that regardless of proposed rule language that allows for the double claiming of RECs for both the 8% target and for the RPS, that such double claiming of environmental attributes is typically prohibited, even through implication, lest the value of the REC itself be called into question. Preventing double counting of renewable attributes is critical to ensuring the stability and integrity of the voluntary REC market (which underlies PGE’s national leading voluntary green power program) and prevents consumer confusion in the marketplace. If the proposed rules retain the language about renewable attributes and should the rules require that a REC be used to comply with the 8% target, further environmental claims would be prohibited. If PGE were, for example, to purchase the energy from a small-scale facility and

bank the REC for RPS compliance, if the REC was required to be used to show that the energy and capacity from the project entered the PGE system and thus met part of the 8% target, PGE could not then sell the REC to a third-party without a cloud on that REC.

For these reasons, PGE recommends removing the language for renewable attribute ownership, RECs, and RPS from the proposed rules.

**Issue #2: Eligibility of net metered projects**

Net metered projects should be eligible to count toward the 8% capacity target in ORS 469A.210 following the removal of language for renewable attribute ownership, RECs, and RPS from the proposed rules. As previously noted, the statute defines two specific requirements for project eligibility. Net metered projects meet both requirements and we repeat our arguments above to the extent that they apply to net metered projects.

**Issue #3: Denominator and numerator basis**

PGE supports the use of nameplate capacity for both the denominator and numerator values in the equation to determine progress toward the 8% capacity target. Because ORS 469A.210 is a capacity target, it is reasonable to use nameplate capacity for resource supply values. Using nameplate capacity provides both consistency with the statute and ease of verification. Using nameplate capacity for both the denominator and numerator values is the easiest way to ensure an “apples to apples” comparison of the projects.

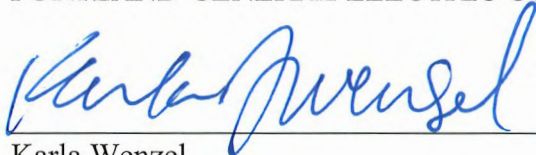
**Conclusion**

PGE appreciates the hard work of Commission Staff and the Administrative Hearings Division to draft the proposed rules. Should you have any questions regarding these comments, please contact Colin Wright at (503) 464-8011.

Please direct all formal correspondence and requests to the following email address [pge.opuc.filings@pgn.com](mailto:pge.opuc.filings@pgn.com).

Respectfully submitted,

PORTLAND GENERAL ELECTRIC COMPANY



Karla Wenzel  
Manager, Pricing and Tariffs  
121 SW Salmon Street, 1WTC0306  
Portland, OR 97204



**Portland General Electric**  
121 SW Salmon Street • Portland, Ore. 97204  
PortlandGeneral.com

November 29, 2018

***VIA ELECTRONIC FILING***

puc.filingcenter@state.or.us

Public Utility Commission of Oregon  
201 High Street S.E., Suite 100  
Salem, OR 97308-1088

Attn: Filing Center

**RE: AR 622 – PGE’s Amended Comments for Staff’s Draft Proposed Language**

These amended comments are intended to replace comments originally filed in AR 622 on November 28, 2018.

Portland General Electric Company (PGE) appreciates the opportunity to provide these comments in response to Public Utility Commission of Oregon (Commission) Staff’s draft proposed language for rulemaking regarding the implementation of community-based renewable energy provisions in ORS 469A.210.

As a threshold issue, PGE continues to have concerns regarding the propriety and scope of this rulemaking. As stated in the workshop held by Staff on October 4<sup>th</sup>, while PGE agrees that the Commission has the authority to review utility progress toward meeting the goal established in ORS 469A.210 and perhaps even establish standards for how a utility would report that progress, we continue to object to the assertion of agency authority over implementation of, or compliance with this statute. We believe that the Legislative Assembly has not provided clear authority for rulemaking in this context and that belief is bolstered by the legislative history behind this statute and the rest of ORS 469A.005-.210. Therefore, language in Rule 1 stating that the rules are intended to “implement ORS 469A.210” and provisions in Rules 3 and 6 expressing that the Commission will adjudge “compliance with the standard” are outside the scope of the authority provided to the Commission by the legislature.

Additionally, Staff notes that the solar capacity standard rules were used as a template for many of these draft rules for community renewables. By way of background, the solar capacity standard was enacted in 2009 with a rulemaking in 2010, and then repealed in statute in 2016 and in rule, in 2018 (AR 613). The standard required, by 2020, electric companies to build at least 20 MW of solar nameplate with systems of a size of at least 200kW and not to exceed 5 MW. PGE’s share of that statewide standard was 10.9 MW. PGE does not believe it is appropriate to use the solar capacity standard rules as a template given the difference in the statutory frameworks. Further, the solar capacity standard was set forth in ORS 757.370 and explicitly provided authority to the Commission to adopt rules, stating “The commission may adopt rules implementing and enforcing this section.” ORS 757.370(1). No such grant of authority exists in the community renewables

legislation. The statutes explicitly provided in ORS 757.375(1) that the utility's actions to comply with the solar capacity carve out could be used as credit toward Renewable Portfolio Standards (RPS) compliance. Again, no such provision exists with the community renewables. This statutory provision was repeated in the administrative rules (Division 84-0080) when the solar capacity standard rules were adopted. Those rules also included a provision for the RPS implementation plan to include the solar capacity standard. This makes sense given the explicit authority to count compliance with solar carve out as RPS compliance. The rules also included a provision that allows the Renewable Energy Certificates (RECs) to be double counted for RPS compliance if the solar PV system is operational before 1-1-2016, installed in Oregon, and met the rule standards. That mirrored the ORS 757.375 provision that allowed electricity from solar PV systems physically located in Oregon to be used by an electric company to comply with the RPS under ORS 469A.005-.210, and to count two times toward RPS compliance.

Our further comments will address four specific issues in the draft proposed language:

- 1) Rule 4 – Qualifying Projects and Oregon only requirement
- 2) Rule 5 – Eligible Projects and Rule 9 – RECs and Compliance with the RPS
- 3) Rule 7 – Compliance Report
- 4) Rule 10 – Implementation Plans

#### **Issue #1: Rule 4 – Qualifying Projects and Oregon only requirement**

The draft proposed language in Rule 4(1) states the following:

“To qualify for the standard in [Rule 3] energy projects must be located in Oregon, and...”

PGE is opposed to the requirement that qualifying projects must be located in Oregon for three primary reasons:

First, nothing in the plain text of the statutory language of ORS 469A.210 supports that qualification and the Commission should not read such a requirement into the statute.

Second, imposing an Oregon-only requirement is likely impliedly preempted by the so-called “Dormant Commerce Clause” of the U.S. Constitution. A detailed discussion of the constitutional principle cannot be had here. However, the principle provides that state laws must not discriminate against out-of-state actors or have the effect of favoring in-state economic actors unless the state has no other reasonable means of advancing a legitimate local purpose.

Third, ORS 469A.210(2) states that “...at least eight percent of the aggregate electrical capacity of all electric companies that make sales of electricity to 25,000 or more retail electricity consumers in this state must be composed of electricity generated by...” This language uses retail electricity customers in Oregon as the basis for determining if a utility must meet the standard. PGE may build or buy the output of generating projects located outside the state to serve our retail electricity customers in Oregon. Thus, it is reasonable for the criteria used to determine qualifying energy projects also be based on sales of the generating output to retail electricity customers in Oregon, irrespective of facility location.

Additionally, PGE notes that the Oregon Legislative Assembly considered provisions to restrict the location of community renewable projects and has rejected those proposals each time it has considered them. In 2016, the legislature considered the -18 amendments to HB 4036 (the bill that became SB 1547). Those amendments would have required that the community renewable projects be interconnected with a transmission or distribution system located in the state. This is a de facto Oregon situs requirement. In the same session, the -A3, -A4, -A5, -A6, -A8, -A11, -A17 amendments to SB 1547, containing the same interconnection requirement, were all rejected. In 2017, the legislature considered amendments to ORS 469A.210 through SB 339 and did not add a locational requirement. It also considered, but failed to adopt, HB 2136, which, among other things, would have required community renewable projects to have a first point of interconnection within the balancing authority of an Oregon electric company. This too, would have resulted in a de facto Oregon situs requirement. PGE believes that the failure by the legislature to adopt an Oregon situs requirement, after being presented with multiple opportunities to do so, should be considered for its value in this rulemaking.

PGE recommends that the Oregon requirement be dropped from the rule.

### **Issue #2: Rule 5 – Eligible Projects**

#### **Rule 9 – RECs and Compliance with the RPS**

The draft proposed language in Rule 5 requires the utility to own or otherwise have the rights to the environmental attributes associated with the energy produced by an energy project to count that project toward the standard. Rule 9 provides clarifying language that RECs associated with a project whose capacity is used to meet the standard can still be used for banking, RPS compliance, or a voluntary renewable energy tariff.

PGE is opposed to both rules. The language in Rules 5 and 9 combine RPS compliance with the requirements stated in ORS 469A.210. These rules propose a proxy method that uses the environmental attributes and RECs tied to a project's renewable energy production, measured in megawatt-hours (MWh), as a means of determining if a project's capacity, which is measured in megawatts (MW), will be eligible to count toward the standard in ORS 469A.210. This proposal is inconsistent with the history behind the creation of RECs, the measurement of renewable energy production, and eligible projects language that is clearly stated in ORS 469A.210. Capacity is repeatedly used throughout ORS 469A.210. The statutory language explicitly states that the 8 percent standard is determined by electrical capacity and eligible renewable energy projects are measured by generating capacity. The requirements stated in ORS 469A.210 do not support Rule 5 or Rule 9.

Further, Oregon's community renewable requirement is not part of the RPS; it is not a "carve-out" but a separate standard based solely on *capacity*. For these reasons, PGE recommends the REC approach be deleted from the draft rules.

### **Issue #3: Rule 7 – Compliance Report**

As previously mentioned, PGE believes the use of "compliance" in Rule 7 is outside the scope of the authority provided to the Commission by the legislature. PGE suggests revising this language

to indicate a "status report" filing with the Commission for demonstrating progress toward the standard rather than compliance.

Additionally, Rule 7(h) should be removed from the reporting criteria for those reasons stated in Issue #2.

#### **Issue #4: Rule 10 – Implementation Plans**

PGE has concerns that Rule 10 is outside the scope of the authority for this rulemaking as provided in Commission Order No. 18-322. The staff memorandum that proposed this rulemaking stated that the purpose for the rulemaking was to "clearly define" community-based, renewable energy projects and to determine how the "mandate in ORS 469A.210 will [] be implemented and evaluated." Rule 10 essentially modifies the requirements imposed by ORS 469A.075 and validly adopted rules in OAR 860-083-0400. That rule governs the elements of the implementation plans for meeting the requirements of the renewable portfolio standard, of which ORS 469A.210 is not a part. The renewable portfolio standard applicable to large utilities is found at ORS 469A.052. As the language in OAR 860-083-0400(1) makes clear "each electric company that is subject to ORS 469A.052 must file an implementation plan." The authority provided to Staff for this rulemaking from the Commission applied only to the implementation of ORS 469A.210 and not any other statute, including ORS 469A.052. PGE believes that amending rules that were validly adopted pursuant to ORS 469A.052 by reference are outside the scope of this rulemaking. Instead, PGE suggests a revision to Rule 10 to address this issue: "...each electric company subject to the standard...[may] incorporate its plan to achieve..."

#### **Conclusion**

PGE appreciates Staff's work on the draft proposed language given the expeditious timeline for the AR 622 rulemaking and looks forward to continued work with stakeholders. Should you have any questions regarding these comments, please contact Colin Wright at (503) 464-8011.

Please direct all formal correspondence and requests to the following email address [pge.opuc.filings@pgn.com](mailto:pge.opuc.filings@pgn.com).

Respectfully submitted,

PORTLAND GENERAL ELECTRIC COMPANY



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Karla Wenzel  
Manager, Pricing and Tariffs  
121 SW Salmon Street, 1WTC0306  
Portland, OR 97204



**Portland General Electric**  
121 SW Salmon Street • Portland, OR 97204  
portlandgeneral.com

October 13, 2025

***Via Electronic Filing***

Public Utility Commission of Oregon  
Attn: Filing Center  
201 High Street, S.E.  
P.O. Box 1088  
Salem, OR 97308-1088

RE: AR 674 Division 91 Rulemaking Energy Amendments

Dear Filing Center:

Portland General Electric Company (PGE or the Company) respectfully submits this response to Public Utility Commission of Oregon (OPUC or the Commission) Staff's request for final comments on their proposed Division 91 amendments in the AR 674 Informal Rulemaking regarding Small Scale Renewables (SSR). PGE thanks Staff for their continued constructive engagement with utilities and other stakeholders in this matter.

**Position summary**

PGE supports the Commission's intent, stated in Order No. 25-232,<sup>1</sup> to limit the scope of this rulemaking to address clarifications regarding the two categories of issues raised in PacifiCorp's DR 58 petition for a declaratory ruling on small-scale renewable issues: the SSR compliance obligation calculation and SSR project eligibility.

With this in mind, PGE agrees with and supports Staff's proposed amendments to OAR 860-091-0020, which address Aggregate Electrical Capacity and clarify the inputs necessary for utilities to calculate compliance with the SSR standard.

Furthermore, PGE agrees with and supports Staff's proposed amendments to OAR 860-091-0030(1), (2)(a) and (2)(b), which clarify SSR project eligibility and are directly responsive to PacifiCorp's petition, in keeping with the limited scope the Commission directed for this proceeding.

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<sup>1</sup> *In the Matter of PacifiCorp, Petition for Declaratory Ruling on Small-Scale Renewable Issues*, Public Utility Commission of Oregon, Order No. 25-232, June 26, 2025. ("This order memorializes our decision . . . to . . . open a rulemaking docket . . . with the modification to limit the scope to addressing clarifications regarding the two categories of issues raised in PacifiCorp's filing [including] SSR project eligibility.") See also, PacifiCorp Petition for Declaratory Ruling on Small-Scale Renewable Issues, DR 58, May 2, 2025, page 6 ("To resolve any ambiguity, PacifiCorp requests the Commission declare whether the following resources are also SSR-eligible: (1) CSP projects; (2) resources that interconnect with PacifiCorp's system through surplus interconnection services; and (3) scenarios where multiple SSRs are located within close proximity of each other . . . ."). <https://apps.puc.state.or.us/orders/2025ords/25-232.pdf>

PGE does not, however, support or agree with Staff's proposed amendments for OAR 860-091-0030(2)(c) or -0030(3)(a) or (3)(b). These amendments are not necessary to respond to PacifiCorp's petition and address broad policy questions inconsistent with the limited scope the Commission sought for this rulemaking process. The -0030(2)(c) and -0030(3)(a) and (b) amendments seek to clarify points that have already been made clear in statute and in Commission Order No. 21-464.<sup>2</sup> Rather than clarifying the rules, reopening these points in this proceeding may create ambiguity and invite further process and debate during formal rulemaking that could threaten Staff's stated belief that "a rulemaking can be conducted efficiently to provide guidance to the utilities in as quickly as six months."<sup>3</sup> If these provisions were the starting point for the formal rulemaking, during the rulemaking PGE would strongly oppose any effort to finalize provisions that are not supported by the statutory language and legislative direction.

## Discussion

PGE offered detailed comments on Staff's initial straw proposal in AR 674 regarding SSR eligibility, inclusion of behind-the-meter (BTM) resources, the Scope of ORS 469A.210 and Legislative History. We reiterate those comments here by reference. We also offered point-by-point areas of agreement and disagreement with specific elements of Staff's straw proposal, and we thank Staff for their responsiveness in considering those points and simplifying their current proposal for amendments to the Division 91 rules.

As noted above, PGE supports and agrees with Staff's proposed amendments to OAR 860-091-0020, as well as OAR 860-091-0030(1), (2)(a) and (2)(b). These are straightforward amendments that clarify the rules and are responsive to PacifiCorp's petition within the limited rulemaking scope ordered by the Commission. We note the inherent tension between the language in -0020 for calculation of aggregate capacity in the denominator and the exclusion of BTM resources in OAR 860-091-0030(2)(c) and -0030(3)(a). In -0020, the new language clarifying that aggregate electrical capacity includes resources that are "used to serve Oregon load" implies that other resources "used to serve Oregon load" should also qualify for addition to the denominator. Beyond a shadow of a doubt, BTM resources serve Oregon load when they are used to either reduce energy and capacity needs for serving a customer or when that same resource exports energy to the grid. In both cases, the BTM resource reduces the need for the utility to provide that same energy or capacity. Since the BTM resource ultimately supports load needs, we can bypass the debate over whether utility planning treats it as a load reduction or a supply resource, as the statute doesn't require us to make that distinction. If included in the denominator in this fashion, the resource must also be included in the numerator.

With regards to Staff's proposed amendments for OAR 860-091-0030(2)(c) and -0030(3)(a) and (3)(b), PGE believes that these are unnecessary and unhelpful revisions to the rules that require more in-depth investigation and discussion than the current proceeding allows and which give rise to complex legal issues regarding the scope of the statutory requirement. Inclusion of the proposed

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<sup>2</sup> OPUC Order No. 21-464, retrieved from <https://apps.puc.state.or.us/orders/2021ords/21-464.pdf>

<sup>3</sup> OPUC Order No. 25-232, Appendix A, page 8 of 9, retrieved from <https://apps.puc.state.or.us/orders/2025ords/25-232.pdf>

language would fossilize substantive policy decisions that are inconsistent not only with Commission direction in this docket, but also inconsistent with its direction to utilities in other regulatory proceedings. The simple approach to resolution of PGE's concern is understand that adoption of these amendments is not required to dispose of the questions raised in PacifiCorp's petition. But if Staff deems it necessary to go beyond the direction of the Commission in this regard, PGE would ask that, at a minimum, it adopt policy that does not harm current or future opportunities to leverage and value a whole class of distributed energy resources.

Specifically:

- **As stated, these questions regarding BTM resources do not need to be resolved in this rulemaking.** PacifiCorp did not ask for clarification of whether net-metering facilities are SSR eligible. The Commission's direction in Order No. 21-464 was that BTM resources were not eligible at that time and that finding requires no reinforcement or clarification. Thus the proposed -0030(3)(a) amendments are unnecessary. Adopting the draft rule would ignore the flexibility the Commission provided in Order No. 21-464 to potentially include BTM resources in the future.<sup>4</sup> The current informal rule process afforded no opportunity for such a demonstration and lacked even substantive discussion of how such a demonstration might be made. PGE disagrees with the Commission determination in Order No. 21-464 regarding qualification of BTM resources but accepted the decision because it did not foreclose the possibility that utilities could demonstrate eligibility in the future without requiring further rulemaking or a Commission-granted waiver to the rules, which is what would be necessary if this amendment is adopted at this time. A better approach, in the "do no harm" category, if Staff were determined to add language on this topic in rule, would be to codify the Commission's flexible approach and provide criteria for how a showing or demonstration could be made.
- **The proposed amendments for OAR 860-091-0030(2)(c) and -0030(3)(a) and (3)(b), taken together, do not in fact clarify but rather risk creating confusion about what resources are SSR eligible.** No party has expressed uncertainty about whether energy storage systems are eligible resources, for instance. They are not generating facilities and are not RPS-eligible, so there is no need to specify in rule that they do not qualify. At the same time, specifying that front-of-meter resources that are incorporated into a microgrid or other resilience project configuration are SSR eligible creates ambiguity as to whether or not a behind-the-meter (BTM) resource incorporated into a microgrid or other resilience project configuration would be eligible (so long as, PGE assumes, the system is not also net-metered and falls under the -0020 exception). PGE cannot divine a logical policy reason for including FTM resources in microgrids but not BTM resources in microgrids, especially if the BTM resource is grid connected when not directly supporting the microgrid. Further, PGE notes that this proposed rule adoption is premature, given that the legislature recently directed the OPUC to adopt rules regarding microgrid development.

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<sup>4</sup> OPUC Order No. 25-232, Appendix A, page 7 of 9 ("In the future, such resources may be considered a more active part of the utility's capacity portfolio, and we are willing to revisit this determination upon a demonstration that this paradigm has changed in ways that make customer-owned resources part of a utility's supply portfolio.")

PGE believes that any treatment of microgrid resources under the SSR should be determined after the microgrid rulemaking to ensure consistency.

- **The proposed amendments reduce the incentive to create potential value propositions for innovative utility/customer partnerships.** Regardless of whether the proposed rules are read to mean only net-metered BTM resources are excluded from SSR eligibility, or that all BTM resources are excluded regardless of whether they are net-metered, this appears to work against Commission guidance and direction in other dockets where utilities are being encouraged to find ways to more closely integrate customer-owned resources into their systems and to create incentives for customers to participate. Walling off any potential for BTM resources to contribute to SSR compliance effectively creates an incentive structure where there is no value proposition for utilities to pursue these resources, and on the flip side creates an incentive structure that is almost entirely focused on acquisition of PURPA-qualifying and Community Solar Program resources – two classes of resource that already offer substantial incentives to potential developers at a substantial cost to utility customers.<sup>5</sup> This appears inconsistent with the Commission's and stakeholders' strong emphasis on the need to consider and advance customer affordability, flexibility, and resilience across all aspects of utility resource planning.
- **Each of the above issues deserve to be considered in the context of a better understanding of the costs associated with SSR compliance.** PGE recognizes that there is a statutory obligation for SSR compliance, and that a cost premium for SSR resources may be justified on policy grounds that may, to a degree, color our evaluation of the acceptable impact of SSR compliance on utility customer affordability. That said, we respectfully encourage Staff and the Commission to incorporate an appropriate cost assessment into future consideration of amendments such as those proposed with OAR 860-091-0030(2)(c) and -0030(3)(a) and (3)(b). In order to inform such an assessment, utilities could be directed to file an annual status report prior to the July 1, 2029 compliance reporting date currently reflected in the Division 91 rules. The information required could be the same as outlined currently in the rule and would enable the Commission to track and make transparent the cost and rate impact of SSR compliance while also informing policy decisions relevant to compliance, such as the inclusion or exclusion of BTM resources.

## Conclusion

From the initial adoption of ORS 469A.210 in 2007, and even since the first rulemaking was completed in 2021, the energy landscape has evolved significantly. Utilities are pursuing acquisition and integration of a greater and greater number of renewable megawatts due to renewable standards, fossil fuel siting restrictions, company-driven environmental and

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<sup>5</sup> As noted in previous comments, PGE believes there are valid reasons to not exclude BTM in the calculation of compliance with ORS 469A.210. PGE will not repeat those arguments here, except to state that PGE believes the statute directs utilities to pursue and integrate small scale resources *inclusive* of resources like community solar projects and QF projects that are smaller than 20MW as the draft rules provide, but also that it makes sense to believe that the legislature must have meant that utilities do something else other than what was already required. That something else, in PGE's view, is to obtain and integrate small scale resources from any supplier, regardless of size, location or ownership and ownership structure. To do otherwise inserts requirements and limitations where none exist.

sustainability goals, coal plant shutdowns and greenhouse gas reduction targets; load growth has spiraled upward at rates faster than anticipated; smaller-scale resources, including those behind the meter, have become more economic even when adding capacity improvements like batteries; additional policy drivers, like federal initiatives to drive down the cost of photovoltaics, have come to bear; and affordability of electricity has also come into the foreground as power costs in the region have driven spikes in electricity rates at the same time as macroeconomic factors have pinched household budgets resulting in numerous efforts to restructure how electricity rates are established and imposed. In this context, we need to explore what modifications to the existing rules would give service to this significantly changed energy landscape while being sensitive to the costs of compliance with the requirement. PGE sees consistency with the purpose and plain language of ORS 469A.210 as being the lodestone in this regard.

PGE thanks Staff for the opportunity to provide further comment. We endorse Staff's proposed -0020 and -0030(1), (2)(a) and (2)(b) revisions to the Division 91 rules and encourage the Commission to authorize formal rulemaking to adopt them. We ask that Staff forego the proposed OAR 860-091-0030(2)(c) and -0030(3)(a) and (3)(b) revisions at this time as being unnecessary, creating potential confusion, contrary to law, and likely requiring a more lengthy and extensive review and public discussion than is envisioned in the current proceeding.

We look forward to continued dialogue with all parties during this process.

Sincerely,

s/Jason Salmi Klotz

Jason Salmi Klotz,  
Senior Manager, Regulatory Planning & Strategy



**Portland General Electric**  
121 SW Salmon Street • Portland, OR 97204  
portlandgeneral.com

September 11, 2025

***Via Electronic Filing***

Public Utility Commission of Oregon

Attn: Filing Center

201 High Street, S.E.

P.O. Box 1088

Salem, OR 97308-1088

RE: AR 674 Division 91 Rulemaking Energy Amendments

Dear Filing Center:

Portland General Electric Company (PGE) respectfully submits this response to Staff's Straw Proposal in the AR 674 Division 91 Rulemaking regarding Small Scale Renewables (SSR). PGE thanks Staff for articulating the scope, goals and straw rules for amendment and for facilitating a productive workshop to discuss the compliance obligation ratio and project eligibility.

**Introduction**

PGE approaches this rulemaking from several vantage points and perspectives. First, as the energy landscape has continued to evolve as utilities in the state and in the region continue to pursue acquisition and integration of a greater and greater number of renewable megawatts even as load growth has spiraled upward, we need to explore what modifications to the existing rules would reflect this changed landscape but continue to be consistent with statutory requirements. And second, we should determine whether the case exists for updating the method of calculation of the numerator and denominator such that behind the meter facilities or other resources that are directly supported by customers are reasonably considered part of the utility's aggregate electrical capacity, while battery storage facilities, as non-generating resources, are not seen as part of that capacity. In sum, PGE generally supports a number of Staff's proposals around preserving the value proposition of resources with system and community value but disagrees with Staff proposals that seek to overly complicate the SSR<sup>1</sup> or eliminate from consideration certain types of resources.

**Proposal Response**

PGE's interpretation of SSR eligibility is governed by a two-prong test that is specified in the plain language of the statute – any resource that is less than 20 MW and qualifies under the renewable portfolio standard (RPS).<sup>2</sup> By that test, it is PGE's position that behind-the-meter (BTM) resources

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<sup>1</sup> Such as the proposal to allow qualification of SSR if using surplus interconnection.

<sup>2</sup> [ORS 469A.210 – Goal for community-based renewable energy projects](#)

are SSR eligible. Whether those behind the metered resources are net energy metered (NEM) should not be a primary consideration. The statute creating SSR largely sets out a generic resource procurement requirement, one that helps to offset resource development elsewhere in the system. Excluding net metered resources is a decision based on the policy of statutorily defined compensation for net metered resources, not their operation or contribution to system resource procurement. Additionally, it is PGE's view that ownership – customer, developer or utility – is not a relevant criterion for eligibility because SSRs, in all forms, represent ratepayer funded capacity through the many forms of ratepayer-funded incentives or compensation that support them. Lastly, it is PGE's position that battery storage does not represent a generating facility and therefore should be "counted" in neither the numerator nor denominator of the SSR capacity standard. What follows is a table that summarizes PGE's response to Staff SSR proposal elements as well as an articulation of these positions, grounded in statute and legislative history.

Proposal Elements	PGE Response	Consideration/ Rationale
Behind the meter ("BTM") resources are not eligible SSRs.	PGE disagrees with this proposal.	If Staff believes this prohibition must be reaffirmed in the rule, PGE asks that Staff insert a provision that allows utilities to propose, between 2025 and 2030, a rationale for inclusion of all BTM, including net metered resources, consistent with the Commission order 21-464.
Standalone storage or the storage component of hybrid renewable plus storage systems are not eligible SSRs.	PGE agrees with this proposal.	Storage is not a generating facility.
Generation types that are RPS-eligible are eligible SSRs. SSRs do not need to provide utilities with RECs for retirement for SSR compliance.	PGE agrees with this proposal.	Consistent with the adoption of similar provisions in AR 622.
Generating resources that are community sited or with benefits accessible by community members should count for SSR compliance e.g., Community Solar Program	PGE agrees with this statement regarding community-sited resources being eligible but disagrees with the suggestion that there must be specific benefits accessible by community members to qualify.	A community solar project should qualify for inclusion because it meets the two-pronged test and additionally is located in PGE service territory and supports load. The statute does not provide for specific co-benefits to be required and we should not impute them here. Such a framework if better developed within the appropriate program or resource procurement docket.
Front-of-meter resources incorporated into a microgrid or other resilience project configuration should count for SSR compliance	PGE agrees that all front of meter resources that meet the two-pronged test should count, regardless of configuration or inclusion in a microgrid.	A resource that is BTM at all times and not connected to the grid cannot count in the numerator or denominator.

Resources that are otherwise SSR eligible should count for SSR compliance if they use surplus interconnection	PGE agrees that any resource that is SSR eligible should count. PGE does not agree with language that could be read as a limitation on the two-prong test.	SSR eligibility should depend primarily on resource characteristics rather than interconnection logistics.
Resources that are otherwise SSR eligible should count for SSR compliance if they share an interconnection agreement with other resources and align with PURPA aggregation rules	PGE agrees that any resource that is SSR eligible should count. PGE does not agree with language that could be read as a limitation on the two-prong test.	SSR eligibility should depend primarily on resource characteristics rather than interconnection logistics or PURPA rules.
Community-sited storage resources and grid connected customer-sited storage resources decrease aggregate electrical capacity by the resources' nameplate capacity, and demand response and flexible load programs decrease aggregate electrical capacity by the program capacity	PGE understands the interest in both of these proposals but believes that they raise unnecessary complications as phrased.	We can avoid attempting to utilize these proposals as a way to incentivize certain types of resources through the SSR if we merely allow all eligible BTM resources to qualify, as PGE has suggested, including those with storage but then to avoid unfairly imputing capacity to the numerator, eliminate the isolated storage capacity from the calculation.
Nameplate capacity should be used to calculate the SSR requirement numerator and denominator	PGE agrees with this proposal.	
For resource portfolios that serve customers in multiple states, the SSR requirement numerator and denominator will represent the portion of aggregate generating capacity that Oregon customers pay for in their rates	PGE agrees with this proposal.	
In order to create a clear compliance target, SSR nameplate capacity should be excluded from aggregate electrical capacity for compliance purposes	PGE agrees with this proposal.	
In order to create a clear compliance target, aggregate electrical capacity should be measured one year prior to the compliance date for compliance purposes and compliance reports are required annually beginning in 2029 and will continue annually thereafter.	PGE believes that the current rules provide sufficient clarity on these issues.	An alternative method would be to allow any resources added during the compliance year to be excluded from the denominator until the following compliance year.

### **Inclusion of behind-the-meter (BTM) resources**

PGE's position is that BTM<sup>3</sup> resources should qualify to meet the standard if those resources meet the two-pronged test of ORS 469A.210: less than 20MW in size and generating energy from one of the qualifying energy resources specified in ORS 469A.025.<sup>4</sup> There is nothing in the statutory requirement for SSR that distinguishes between front of meter and BTM resources for purposes of qualification and the Commission should not seek to add additional barriers to qualifying resources that meet the two-pronged test.<sup>5</sup>

This position is consistent with Staff's goal of treating the SSR requirement as a generating capacity standard. In the Commission's adoption of SSR rules in AR 622, the Commission adopted Staff's proposal to use nameplate capacity in calculation of both the numerator and denominator, arguing that this was most consistent with the statutory language.<sup>6</sup> The Commission also reasoned that using the nameplate capacity of "resources serving Oregon customers" for both numerator and denominator best accords with the plain language of the statute. Thus, the question is, do both front of meter and BTM resources (including net metered resources) serve Oregon customers? In Order No. 21-464, the Commission did not directly answer this question when it declined to include net metered resources as qualifying for consideration in the SSR, instead saying that because the "generation nets against the customer's energy usage" and because utilities have "traditionally ... viewed net-metered projects in their load-resource planning as decrements to load" such projects are not considered "part of the utility's resource portfolio." It is PGE's position that net metered resources clearly serve Oregon customers, are paid for, in part, by utility customers through the net billing arrangement and through Public Purpose Charge-funded incentives provided by the Energy Trust, meet the two-pronged test, and therefore should qualify. All stakeholders recognize the opportunity presented by system operationalized and optimized DERs otherwise known as the Virtual Power Plant (VPP). Making a decision now to exclude net metered resources would disincent investment in resources like roof top solar or might even affect the value assessment of net metered resources because they cannot capture the value of being included in the SSR.

While it is true that *sometimes* the generation of a BTM resource nets against usage, there are also many other times during the day and year where this is not true and the BTM resource exports to the grid and is used to serve the load of neighboring energy needs. The idea that the BTM resource nets against usage is bolstered by the administrative structure of the net metering program that

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<sup>3</sup> During the workshop held on August 21, 2025, there was some discussion regarding the qualification of some BTM resources and not others, including net metered resources. Part of the discussion was how to "snap the line" behind the meter to allow such inclusion. PGE believes, as further described in these comments, that there is no logical rationale for including some BTM resources and not others and included net metered resources within the term BTM.

<sup>4</sup> PGE notes that the Commission reiterated this same two-pronged test for "eligibility to count toward the standard." *In the Matter of Small-Scale Renewable Energy Projects*, AR 622, Public Utility Commission of Oregon, Order No. 21-464 at page 9.

<sup>5</sup> ORS 174.010 reminds us that in the construction of a statute, we should not seek to insert what has been omitted.

<sup>6</sup> Order No. 21-464 at 7, 8.

allows crediting over the year, allowing for export “credits” to build up in the summer months while decrementing against those credits in the winter period. Thus, on an annual basis, the netting aspect seems greater than it actually is. The administrative structure actually recognizes the export of energy from these systems and the need for utilities to then serve load when those systems do not produce. The structure also ignores the very real aspect of the constant back and forth of energy consumption, often on a minute-by-minute basis, and the supply that occurs between the customer-generator and the grid.

PGE now has greater than 460MW of net metered, qualifying facilities, feed-in tariff systems, and Oregon Community Solar<sup>7</sup> program facilities enrolled or operating on its system.<sup>8</sup> Of that amount, roughly 358MW of that amount are net metered systems.<sup>9</sup> This latter figure is greater than the nameplate capacity of the Wheatridge wind facility (300MW), PGE's share of the Clearwater Wind Energy Center (311MW), and more than twice the nameplate capacity of the entire community solar program (160MW). In Order No. 21-464, the Commission stated that it was willing to revisit its determination to exclude net metered resources if utilities could demonstrate that the “paradigm has changed in ways that make customer-owned resources part of a utility's supply portfolio.”<sup>10</sup> In the years since this order, net metered facilities enrolled on PGE's system have increased significantly, planning requirements now require utilities to perform distribution system planning, PGE has developed and implemented its AdopDER modeling for understanding the impact of distributed energy resources on the system and offered proposals regarding a VPP and distributed energy resource capability stages.

Moreover, PGE must plan to serve all customers in a manner that reflects the understanding of the energy that comes from this significant amount of dispersed energy resources. That is, PGE must be able to serve all the load customers demand on sunny days and cloudy, in summer and winter, understanding the variability of the 358MW of nameplate capacity energy supplied by NEM systems. Thus, whether they sit on the customer side of the meter or on the utility side of the meter, these energy systems are a resource for meeting load and a resource that must be planned for – something all customers benefit from and lending credence to PGE's interest in qualifying the resources as part of the aggregate electrical capacity in numerator and denominator. Whether PGE has evolved its “approach and orientation toward customer-sited distributed generation”<sup>11</sup> or been made to evolve its approach and orientation, PGE cannot ignore the resource and has been, through practice and Commission direction, including these resources in planning and operations.

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<sup>7</sup> The Oregon Community Solar program was established to give people without access to rooftops parallel treatment to the costs and benefits of solar PV as those customers with roofs. In this case, parallel treatment for OCSP projects and privately-owned NEM projects would require similar treatment under the SSR.

<sup>8</sup> PGE 2024 Distribution System Plan, section 5.1.5, page 78.

<sup>9</sup> Preliminary estimate provided by PGE's interconnection services department. Do not cite.

<sup>10</sup> Order No. 21-464 at 13.

<sup>11</sup> Order No. 21-464 at 13

PGE also views BTM resources as an area overall that is developing in significance in serving load. The development of PGE's 2023 IRP/CEP included an expressed interest in acquisition of 155 aMW of community-based renewable energy resources. PGE has a request for offers currently out for bids and it is likely that some of these resources will be BTM resources. The development of PGE's VPP program will bring the opportunity for PGE to utilize a network of decentralized, medium and small-scale power generating and storage facilities to help balance electrical supply and demand on the grid, especially at peak times.<sup>12</sup> The development of such a dispatchable, coordinated, flexible and resilient power structure will improve the benefits that customer-owned resources bring to the grid, and PGE will provide an incentive structure to customers for their participation. PGE sees no difference between something like the VPP, which will create even greater incentives for customers to contribute to the grid, and what ORS 469A.210 directs utilities to pursue in terms of support for and acquisition of small-scale renewable facilities, but agrees that the storage component of a hybrid renewable system would not affect the calculation of the numerator or denominator because storage does not create any generation. Lastly, exclusion of net metered resources from the SSR would reduce the value proposition of net metered resources for customers by excluding a value from the cost benefit calculation of these behind the meter resources, which do otherwise represent the opportunity for "customer-owned resources part of a utility's supply portfolio."

**Scope of ORS 469A.210 and Legislative History** As noted above, we should not seek to insert what has been omitted in determining the purpose of a statute. Some parties to this docket may believe that the statute requires utilities to comply with the 10 percent mandate solely through front of meter, Public Utility Regulatory Policies Act (PURPA) projects. But several things stand in the way of interpreting that to be the true thrust of ORS 469A.210. The first is simply that PURPA was adopted in 1978 and state statutes implementing the federal law were adopted in 1983.<sup>13</sup> With these laws existing for over 30 years when ORS 469A.210 was amended in 2016, it would have been easy for the legislature to specifically reference ORS 758.505 to 758.555 if the legislature meant to limit compliance to PURPA eligible projects. It did not and we should not read in the requirement and thus discriminate against BTM resources on that basis. Second, ORS 758.525 requires utilities to publish avoided cost rates and offer to purchase energy or energy and capacity from qualifying facilities. Utilities must also make good faith efforts to transmit that energy produced by the qualifying facility.<sup>14</sup> With these requirements already in place, the adoption of the capacity standard would be superfluous.<sup>15</sup> Third, such a PURPA-only mandate would reduce

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<sup>12</sup> See generally, PGE 2024 Distribution System Plan, Chapter 5 ("The VPP is *how* PGE integrates and operates the distribution system with increasingly distributed resources, flexible loads, and technology in an optimized manner to deliver value to customers." Section 5.1.1).

<sup>13</sup> See ORS 758.505 to 758.555.

<sup>14</sup> ORS 758.545.

<sup>15</sup> In 2025, the legislative assembly adopted House Bill 3863 which mandates a standard offer contract be used for any PURPA facility of 10MW or less.

the impetus for the exact type of efforts that are ongoing in PGE's service territory around such things like community-based renewable energy resources or the VPP, to develop diverse resources in terms of technology and location.<sup>16</sup>

Following on the question of whether the legislature intended the capacity standard to be limited only to PURPA facilities, there is also no textual or contextual support in the statute to infer that the legislature intended ORS 469A.210 to be a procurement standard of any subset of renewable energy generation resources other than those that meet the two-pronged test. The best evidence of what the legislature intended a statute to mean is the wording of the statute that it adopted into law.<sup>17</sup> It is not the intent of individual legislators that governs, but the intent of the legislature as a whole that is important.<sup>18</sup> During the workshop on August 21, 2025, advocates provided no textual or contextual support in ORS 469A.210 for denying the qualification of BTM resources generally or net metering resources specifically for purposes of satisfying the statutory requirement.<sup>19</sup> Perhaps that is because there is none. The statutory direction is clear, "the aggregate electrical capacity of all electric companies . . . must be composed of electricity generated by . . . small-scale renewable energy projects with a generating capacity of 20 megawatts or less" that generate electricity from a set of renewable sources, including solar, as delineated in ORS 469A.025 or certain biomass resources. Or stated another way, any solar photovoltaic system that is less than 20 megawatts that provides electricity to support the aggregate electrical capacity of a utility should count toward the 10 percent requirement. Nothing suggests that energy sources smaller than 20MW are excluded below a certain minimum size. Nothing directs the utility to procure those small resources from specific parties or to exclude from the calculation projects under certain ownership or ownership structures. Nothing directs utilities how to procure those resources. And finally, nothing evinces the barest evidence that BTM resources should not count – for all BTM resources support the total energy needed to support load.

PGE agrees with CREA/REC/OSSIA on part of the evolution of the SSR.<sup>20</sup> The original statute provided a goal of 8 percent statewide. In the Renewable Energy Working Group (REWG), the Governor-appointed group that met through much of 2005 and 2006 to create the Oregon Renewable Energy Act (within which ORS 469A.210 was ultimately included), the 8 percent goal was a request of the Community Caucus. That group issued a report that stated that it had discussed

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<sup>16</sup> As the first subsection of ORS 469A.210 states: "The Legislative Assembly finds that community-based renewable energy projects, including but not limited to marine renewable energy resources . . . are an essential element of this state's energy future." PGE believes that for PGE customers, BTM resources are far more "community-based" than a 10MW solar PURPA facility in central Oregon.

<sup>17</sup> *Brown v. SAIF Corporation*, 361 Or. 241, 249 (Or.Sup.Ct. 2017).

<sup>18</sup> *State v. Gaines*, 346 Or. 160, 171 (Or.Sup.Ct. 2009).

<sup>19</sup> *PGE v. Bureau of Labor and Industries*, 317 Or. 606, 610-612 (Or.Sup.Ct. 1993) and *Gaines*, 346 Or. at 171-173, instruct us how to deal with an issue of statutory construction, which is to first look at the text and context of the statute, and then, after that examination even where there is no ambiguity, to then consult legislative history with the court determining the value of such history. And finally to turn to maxims of statutory construction.

<sup>20</sup> <https://edocs.puc.state.or.us/efdocs/HAC/dr58hac337670027.pdf> at 3.

an 8 percent carve-out, setting aside a portion of a Renewable Portfolio Standard for community-scale renewable energy, but decided that that policy was not ideal for Oregon. Instead, the group proposed a mix of actions, including constraining the use of the public purpose charge to projects less than 20 MW and extending the public purpose charge funding through 2025.<sup>21</sup> In his report to Governor Kulongoski, the chair of the REWG, Mike McArthur,<sup>22</sup> noted that the 8 percent goal was agreed to by the Community Caucus in lieu of a carve out target. Thus, the legislative history behind the original goal shows that it was not a procurement standard for specific types of projects or ownership structures, but was to be driven by the goal, direction to state agencies to adopt rules and policies to support the goal,<sup>23</sup> and a separate mix of actions, including the constraining of the public purpose charge to smaller projects.<sup>24</sup> Net metered projects, as eligible to receive incentives under the realigned the public purpose charge, would have been part of the systems meeting the 8 percent.

In 2016, the Oregon Legislative Assembly adopted Senate Bill 1547, which among other things, made the statewide goal applicable to all utilities into a mandate on electric companies serving over 25,000 customers. While SB 1547 was the bill that ultimately was adopted, the legislative debates were conducted regarding the content of that bill over House Bill 4036. Highly relevant for purposes of this discussion are the statements made by CREA, REC and OSSIA as to the intention of the change of the goal to the requirement. In submitted testimony, then Executive Director of the Community Renewable Energy Association (CREA), Brian Skeehan, supported the change from goal to mandate stating the benefits of smaller energy projects:

These projects return to communities significant increased benefits including tax payments and jobs through direct investments and allied services and activities. There is considerable evidence that smaller, nonutility privately developed and community developed projects provide great benefits to local economies. Smaller, decentralized and dispersed generation provides greater grid security and can enhance system reliability, particularly with the increased threat of attacks, physical or cyber on electric infrastructure.<sup>25</sup>

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<sup>21</sup> Since this restructuring of the public purpose charge in 2007, PGE customers have paid hundreds of millions to the Energy Trust for support of energy efficiency, conservation and renewable energy. Incentives from the Energy Trust, paid for by PGE customers, have been instrumental in the installation of thousands of net metered renewable energy facilities large and small, ranging from large methane burning facilities at municipal waste treatment centers to small rooftop solar. PGE believes that customers should not now have to essentially pay twice for the same small-scale renewable facilities – once for the incentives to install and again for PGE to purchase more small-scale produced energy to meet the requirement of ORS 469A210.

<sup>22</sup> Interestingly, eventually the director of CREA.

<sup>23</sup> This provision was removed in the revision of the goal to mandate as part of Senate Bill 1547 (2016), but can be seen in the original bill, Section 24, Senate Bill 838 (2007)

<sup>24</sup> Parties interested in reading the documents referred to by PGE can access PGE's comments in AR 622. They are attached as appendices: <https://edocs.puc.state.or.us/efdocs/HAC/ar622hac134246.pdf>

<sup>25</sup> <https://olis.oregonlegislature.gov/liz/2016R1/Downloads/CommitteeMeetingDocument/88523>

PGE reads this statement to be inclusive of net metered and BTM infrastructure, especially regarding the “privately developed” and “smaller, decentralized and dispersed” aspects. Net metered facilities are privately developed and employ contractors to install them, providing the smaller, decentralized and dispersed generation that he wrote about. Nowhere in Mr. Skeehan’s testimony did he suggest net metered or other BTM infrastructure should not qualify.

Similarly, John Lowe, then executive director of the Renewable Energy Coalition (REC), stated in submitted testimony supporting the conversion to a mandate:

The Coalition supports HB4036 and an amendment addressing the requirement that a prescribed component of non-utility owned renewable energy be attained from existing and new projects.<sup>26</sup>

BTM resources are typically non-utility owned. Mr. Lowe made no comment regarding the exclusion of net metered resources or distinguishing ownership structures, and thus we can conclude that the comment regarding “non-utility owned” would necessarily include net metered resources. The Oregon Solar Energy Industries Association (OSEIA – today OSSIA, or the Oregon Solar and Storage Industries Association) submitted general testimony in support of HB 4036, and did not provide any comment regarding the 8 percent mandate at all.<sup>27</sup>

Future Commissioner Les Perkins wrote in support of the passage of HB 4036 with the mandate amendment and asked that by 2025 “at least 8% of Oregon’s investor-owned utilities’ retail electric load come from small-scale community renewable energy projects interconnected with an Oregon utilities’ transmission or distribution system with a generating capacity of 20MW or less.” He further suggested that “[s]mall-scale renewable energy projects provide vital jobs, improve the local economy and provide valuable distributed green energy.”<sup>28</sup> Again, all of these items and goals, including the jobs, connection at the distribution level and the improvement to the local economy are provided as much by the installation of net metered and BTM systems as they are by those in front of the meter or QF facilities. During the workshop on August 21, 2025 Greg Adams, representing CREA, asserted that the legislative history regarding the exclusion of net metering from the SSR calculation was clear, citing his comments in DR 58.<sup>29</sup> However, a review of those comments shows that he rests his notion of “unambiguous” legislative history on only one quote from a floor speech by Representative Ken Helm.<sup>30</sup> As the court stated in *Brown v. SAIF Corporation*, the statement of one legislator “is an especially slim reed on which to rest” a reading

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<sup>26</sup> <https://olis.oregonlegislature.gov/liz/2016R1/Downloads/CommitteeMeetingDocument/83719>

<sup>27</sup> <https://olis.oregonlegislature.gov/liz/2016R1/Downloads/CommitteeMeetingDocument/86826>. PGE notes that OSEIA changed its name since that time.

<sup>28</sup> <https://olis.oregonlegislature.gov/liz/2016R1/Downloads/CommitteeMeetingDocument/83526>

<sup>29</sup> <https://edocs.puc.state.or.us/efdocs/HAC/dr58hac337670027.pdf>

<sup>30</sup> *Id.* at 4.

regarding the meaning of a statute.<sup>31</sup> Further, Rep. Helm's statement is further undercut by the fact that he made the remark regarding the *increase* from 8 percent to 10 percent, not the change from a goal to a mandate.

It is PGE's view that the legislative history is unambiguous, but based on the significant weight of what legislators were considering when turning the 8 percent goal into a mandate,<sup>32</sup> from the same entities that Mr. Adams represents, was that net metered and BTM projects were not excluded from consideration. In fact, the elements that such projects bring to the table in terms of jobs, economic development, diversity, reliability and connection at the distribution level, are the same ones that CREA and REC supported during the debates and sought from the change of the goal to a mandate.

## Conclusion

In summary, PGE advocates the positions below:

**Inclusion of Behind-the-Meter (BTM) Resources:** PGE argues that BTM resources, including net-metered systems, should be eligible as SSRs because they meet the statutory two-pronged test of being less than 20 MW and generating renewable energy. PGE states that excluding these resources would disincentivize investment in things like rooftop solar and might affect their value assessment. PGE believes that net-metered resources already serve Oregon customers and are partially paid for through utility customers via net billing and public purpose charge-funded incentives. The company also argues that it is "presumptive to decide" that these resources don't count simply because of their current operational capabilities, as they have future potential to be utilized in a VPP.

**Net-metered resources with storage:** PGE agrees that standalone battery storage is not a generating facility and should not be counted in the SSR capacity standard.

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<sup>31</sup> *Brown*, 361 Or. at 271. In Oregon, the most persuasive legislative history reflects consistent themes echoed throughout the legislative process, *see Gaines*, 346 Or at 172 n.9; and *In re Denton*, 145 Or App 381, 400 (1996), *aff'd* in part, *rev'd* in part on other grounds, 326 Or 236 (1998). Legislative statements which represent a wider swath of legislators, not just the comments of one lone legislator, are more persuasive. *See Dep't of Consumer & Bus. Servs. v. Muliro*, 359 Or 736, 753 (2016). Critically, "cherry-picked quotations of single legislators or of non-legislator witnesses have to be carefully examined." *Muliro*, 359 Or at 753. Federal cases echo Oregon in this regard. In *Weinberger v. Rossi*, 456 US 25, 35, n. 15 (S.Ct. 1982), the US Supreme Court noted that the contemporaneous remarks of a sponsor of legislation are not controlling in analyzing legislative history. Citing that case, the US Court of Appeals for the Second Circuit noted that "Floor speeches are of particularly limited assistance in resolving highly controversial issues of Congressional intent. Since any member can make a floor speech, there is scant utility in totaling up the number of speeches on each side of an issue and attempting to divine congressional intent from the quantity of Congressional Record pages generated on either side." *Butts v. City of New York Dept. of Housing Preservation and Development*, 990 F.2d 1397, 1405 (2<sup>nd</sup> Cir. 1993). And isolated remarks by legislators on the floor, even the sponsor, are entitled to little to no weight in analyzing legislative history. *See, Chrysler Corp. v. Brown*, 441 US 281, 311 (S.Ct. 1979) (discussing competing comments made on the floor in Congress).

<sup>32</sup> These are the "consistent themes" that *Gaines* directs us to consider.

**The value of net-metered resources:** Excluding net-metered resources from the SSR would reduce the value proposition of these resources by removing a potential value from their cost-benefit calculation. This would hinder the ability of customer-owned resources to be considered part of a utility's supply portfolio.

**Legislative history:** PGE has provided a detailed analysis of legislative history to support its position. The company argues that the legislature could have easily referenced specific federal laws like PURPA if it had intended to limit compliance to PURPA-eligible projects, but it did not. PGE also highlights that testimony from key advocates for the mandate change supported projects that were "privately developed," "decentralized and dispersed," and provided benefits like jobs and local economic development. PGE argues that these descriptions are inclusive of net-metered infrastructure.

**Refutation of counterarguments:** PGE directly refutes the idea that legislative history "unambiguously" excludes net-metered resources from the SSR. It counters this claim by pointing out that a key argument for exclusion is based on a single quote from a floor speech, which is a "slim reed" on which to base a reading of a statute. PGE asserts that the available legislative history actually supports the inclusion of BTM resources.

PGE thanks Staff for its proposal and for the opportunity to contribute to SSR policy formation. We look forward to continued dialogue with all parties during this process.

Sincerely,

s/Jason Salmi Klotz

Jason Salmi Klotz,  
Senior Manager, Regulatory Planning & Strategy



**Portland General Electric Company**  
121 SW Salmon Street • Portland, OR 97204  
portlandgeneral.com

November 5, 2021

***VIA ELECTRONIC FILING***

Public Utility Commission of Oregon  
201 High St. SE, Suite 100  
Salem, OR 97308-1088

Re: **AR 622 – PGE’s Comments on Revised Proposed Rules**

Filing Center,

Portland General Electric Company (PGE) appreciates the opportunity to provide these comments in response to the Public Utility Commission of Oregon (Commission) Notice of Proposed Rulemaking to adopt rules In the Matter of Small-Scale Renewable Energy Projects Rulemaking.

PGE provides these comments in two parts. The first part of our comments relates directly to the Commission’s rulemaking authority regarding ORS 469A.210. PGE believes that the Commission must first determine whether it holds rulemaking authority to adopt rules in this matter, something that the Commission does not have in this case. The second part of our comments relates to the rules themselves and asks the Commission to consider them, if after a review of its authority the Commission determines that it does have authority to adopt rules implementing ORS 469A.210.

**I. Commission Rulemaking Authority Regarding ORS 469A.210**

In written comments made in this docket on November 29, 2018, and in verbal comments made during the Staff led workshop on October 4, 2018, PGE raised concerns regarding whether the Legislative Assembly provided authority for the Commission to adopt rules to implement ORS 469A.210. We incorporate those comments here by reference.

Fundamentally an agency must have the authority to adopt rules implementing a statute, and, if that authority is lacking, the rules themselves can be called into question. ORS 183.400 (4) provides in part that a court may declare a rule invalid if it “(b) Exceeds the statutory authority of the agency.” Our task then is to determine the statutory authority of the agency in regard to ORS 469A.210 and, if it is found that there is no such authority, further action on this rulemaking must cease.

In an Oregon Supreme Court case, *Coffey v. Board of Geologist Examiners* 348 Or. 494 (2010), the court considered “whether an agency is required to promulgate rules” and determined that the question is “a matter of statutory interpretation.”

“If an agency is required to adopt a rule through rulemaking proceedings, that requirement must be found through an analysis of the specific statutory scheme under which an agency operates and the nature of the rule that the agency wishes to adopt. When no statute expressly requires an agency to make rules... a reviewing court examines the statutory text and context pertaining to the agency’s delegated responsibilities ... to discern whether the legislature nonetheless impliedly intended to require the agency to make rules concerning the subject matter in question....” *Coffey* at 498.

The *Coffey* decision holds that agency authority can be explicit, where the legislature has provided directly for rulemaking, or implicit through the agency’s general delegated authority and an indication that the legislature intended for rules to be adopted. The court went on to quote *Trebesch v. Employment Division*, 300 Or. 264 (1985) at length:

“In the absence of an explicit directive, the breadth and kind of responsibility delegated to the agency by the statutory term (fact-finding, applying an ambiguous law, or developing policy) will be one, but not a dispositive, factor which may indicate an implicit directive from the legislature for rulemaking. In addition, the tasks the agency is responsible for accomplishing, and the structure by which the agency performs its mandated tasks, all of which are specified in an agency's authorizing legislation, must be examined as a whole in order to discern the legislature's intent with regard to rulemaking.” *Trebesch*, [300 Or. at 270, 710 P.2d 136](#).

**1) The Legislature did not provide *implicit* authority to the Commission to adopt rules for ORS 469A.210**

We start by taking the second prong of this investigation first, to determine whether the legislature, absent an explicit direction “impliedly intended to require the agency to make rules.” The Commission’s general rulemaking authority is found in ORS 756.060 and it provides in part that:

“the Commission may adopt and amend reasonable and proper rules and regulations relative to all statutes *administered* by the commission.” (emphasis added)

It was our position in 2018, and continues to be, that while the legislature provided significant authority to the Commission within ORS 469A.005 to 469A.210, the legislature never implicitly directed the Commission to administer ORS 469A.210.<sup>1</sup> In this opinion, we look to the plain meaning of the word “administer” and use the Merriam-Webster definition “to manage or

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<sup>1</sup> In *Couey v. Atkins*, 357 Or. 460 (2015), the Oregon Supreme Court was called to interpret the term “likely.” After noting the question of statutory construction and the need to apply the familiar principles set out in *PGE v. Bureau of Labor and Industries*, 317 Or. 606 (1993), the court went on to notes that two newer cases, *State v. Dickerson*, 356 Or. 822, 829 (2015) and *Jenkins v. Board of Parole*, 356 Or. 186, 194 (2014), provide that the court assumes that for terms undefined in statute, it will assume that the legislature intended the term to convey its ordinary meaning and that if the term is not a term of art, it will ordinarily begin with its dictionary definition.

supervise the execution, use or conduct of.”<sup>2</sup> PGE believes that the Commission may manage or supervise the execution of, and therefore adopt rules regarding, electric company compliance with a renewable portfolio standard (RPS) pursuant to the statutory structure of ORS 469A.005 to 469A.210, but ORS 469A.210 is not a renewable portfolio standard.

a) **The Oregon Legislature did not provide any agency with implicit authority to administer ORS 469A.005 to 469.210**

The Oregon Legislature carefully divided the authority to implement Senate Bill (SB) 838 (2007) (*codified* at ORS 469A.005 to 469A.210) between the Commission, the Oregon Department of Energy (ODOE) and the consumer-owned utilities. Both agencies received specific rulemaking and implementation authority numerous times throughout the bill. The specific instances of authority granted to the Commission are summarized below (emphasis ours):

- ORS 469A.065: The Commission “shall establish procedures for implementation of *the renewable portfolio standards* for electricity service suppliers.”
- ORS 469A.075: “An electric company that is subject to *a renewable portfolio standard* shall develop an implementation plan for meeting the requirements of *the renewable portfolio standard* and file the implementation plan with the Public Utility Commission,” and the commission “shall adopt rules ... establishing requirements for the content of implementation plans” and the procedure for acknowledgement of those plans.
- ORS 469A.100: The Commission shall “establish the annual revenue requirement” for electric utilities used in the determination of the “incremental cost of compliance with *a renewable portfolio standard.*”
- ORS 469A.150: The Commission shall adopt rules to “establish a process for allocating the use of renewable energy certificates by an electric company that makes sales of electricity in more than one state.”
- ORS 469A.170: Each electric utility and electric service supplier “that is subject to *a renewable portfolio standard* [to] make an annual compliance report ... to the Public Utility Commission.”
- ORS 469A.180: The Commission shall “establish an alternative compliance rate for each compliance year for each electric company ... that is subject *to a renewable portfolio standard.*”
- ORS 469A.200: The Commission may impose a penalty on an electric company or electricity service supplier “that is subject to *a renewable portfolio standard* under ORS 469A.005 to 469A.210” for failing “to comply with *the standard.*”

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<sup>2</sup> Found online here: <https://www.merriam-webster.com/dictionary/administer>

In all of these, note that the Commission's authority, including rulemaking, related directly to implementation of, and compliance with, an RPS by an electric company or electricity service supplier. ODOE received authority, among other things, to adopt rules regarding low-impact hydroelectric facilities in ORS 469A.020, to adopt rules for types of energy sources that may be used to comply with a RPS in ORS 469A.025, and to establish the renewable energy certificate system in ORS 469A.130. Consumer-owned utilities received the ability, among other things, to establish procedures for implementation of an RPS by electricity service suppliers (ESS) selling electricity in their service territory (ORS 469A.065), establish revenue requirements for the cost cap (ORS 469A.100), and establish their own compliance reports (ORS 469A.170).

Due to the split authority for implementation, in no instance was either agency given implicit authority to give effect to or administer the entire series of ORS 469A.005 to 469A.210. This is due to one very good reason: providing such general implicit authority would have meant creating direct conflicts between the Commission and ODOE or between the Commission and the consumer-owned utilities. Thus, instead the legislature opted to provide explicit authority multiple times to each agency and to the consumer-owned utilities. This structure made clear which statutes were to be given effect by which agency or by the governing boards of the consumer-owned utilities.

Therefore, in PGE's view, because the legislature was explicit where authority was granted, to avoid conflicts and to ensure that authorities did not incidentally overlap, it did not implicitly provide authority to administer ORS 469A.210. To interpret that structure differently, would fly in the face of the otherwise careful and methodical construction of ORS 469A.005 to 469A.210.

**b) ORS 469A.005 to ORS 469A.210 is not the Renewable Portfolio Standard and ORS 469A.210 is not a Renewable Portfolio Standard**

As noted above, in nearly every instance where the Commission was provided with authority, the language also provides that the authority relates to an entity subject to "a renewable portfolio standard." (See bold emphasized statutory excerpts above). If the series ORS 469A.005 to 469A.201 is an RPS or if ORS 469A.210 itself is a separate RPS, then arguably the Commission could have implicit authority to administer the statute. PGE believes however that neither the entire series nor ORS 469A.210 is an RPS.

While colloquially known as "the Renewable Portfolio Standard," SB 838 as adopted was more than just an RPS, it was a "comprehensive renewable energy policy for Oregon."<sup>3</sup> The bill's title was actually "The Oregon Renewable Energy Act,"<sup>4</sup> (the Act) and was so named because it contained policies and directives other than RPS requirements, including: the goal for small-scale/community-based renewable energy projects, a requirement that all electric utilities adopt green power rates and a green jobs study. Any informal reference to the entirety of ORS 469A.005 to 469A.210 as "the RPS" is therefore, over-broad and incorrect.

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<sup>3</sup> See the preamble to Senate Bill 838, found here:

<https://olis.leg.state.or.us/liz/2007R1/Downloads/MeasureDocument/SB838>

<sup>4</sup> The preamble to Senate Bill 838 specified that "this 2007 Act may be cited as the Oregon Renewable Energy Act."

Oregon has three RPSs, two of which apply to utilities (ORS 469A.052 and ORS 469A.055) and one that applies to ESSs (ORS 469A.065). Where the Act uses the term “a renewable portfolio standard” it means one of three standards embedded in the larger Oregon Renewable Energy Act. The plain reading of the statutory framework supports the reading that the RPS that electric companies must comply with are one of those two, and that ORS 469A.210 is not an RPS that must be complied with:

“Electric utilities must comply with the applicable renewable portfolio standard described in ORS 469A.052 or 469A.055.” (ORS 469A.050 (1)).

Perhaps no clearer example of how the legislature has viewed the small-scale/community-renewables requirement as separate and distinct from an RPS can be found in the amendments to ORS 469A.120 made by SB 1547 (2016). Prior to 2016, the language in ORS 469A.120 provided that electric companies could seek cost recovery for “all prudently incurred costs associated with complying with a renewable portfolio standard.” In Section 11 of SB 1547, the legislature changed that language to read as it currently does: an electric company may recover in rates “all prudently incurred costs associated with complying with ORS 469A.005 to 469A.210.” This change was necessary because the small-scale/community-renewables goal was modified into a mandate and would have been unnecessary if ORS 469A.210 was either part of an RPS or was itself an RPS. If that were the case, electric companies would have already had the ability to recover all prudently incurred costs.

The next legislative session, in 2017, the legislature adopted SB 339 to fix an issue caused by the adoption of Senate Bill 1547 (2016). The creation of the series ORS 469A.005 to 469A.210 ensures that definitions provided in ORS 469A.005 apply to terms found in ORS 469A.210. “Renewable energy source” as found in ORS 469A.005 means “a source of electricity described in 469A.025.” In ORS 469A.025, those sources of electricity are those “types of energy [that] may be used to comply *with a renewable portfolio standard.*” (emphasis ours).

Because there was concern that ORS 469A.210 was not a renewable portfolio standard, SB 339 added language to ORS 469A.210 (2)(a) that states that the 8% mandate may be met with generation sources that utilize “a type of energy described in ORS 469A.025.” This language would not have been necessary if ORS 469A.210 was a part of a RPS or was itself an RPS. Thus, because the Commission’s explicit authority in ORS 469A.005 to 469A.210 relates directly to implementation of an RPS, and because neither ORS 469A.210 is an RPS nor is the whole series an RPS, the granted authority does not extend to an implicit authority to administer something in the series that is not an RPS.

**c) The inclusion of ORS 469A.210 in the series ORS 469A.005 to ORS 469A.210 ensures only that definitions apply**

Statutory series are created by bill language and the codification process. Within SB 838 were a number of references to “sections 1 to 24 of this 2007 Act.” When a bill goes through the codification process, those section numbers are assigned a series reference, in this case: ORS 469A.005 (formerly section 1) to 469A.210 (formerly section 24). The creation of a series does

not necessarily join the statutes together except as specifically provided, typically in relationship to definitions, penalties and other references. As stated in the Legislative Counsel's drafting manual:

“A “series” is a consecutive string of ORS sections created by a bill with an explicit reference within the bill. When the provisions are codified during compilation, the reference to the sections (sections 1 to 10 of this 2007 Act) are replaced by ORS section numbers. Series may share penalties, definitions, rulemaking authority or other provisions applicable to the series to allow it to operate together as a coherent whole.”<sup>5</sup>

Similarly, the preface to the Oregon Revised Statutes provides that notes regarding whether a statute is added to a series or a chapter are there to “remind the user that definitions, penalties and other references to the series should be examined carefully.”<sup>6</sup>

The Act did not include generally applicable penalty provisions<sup>7</sup> or rulemaking authority<sup>8</sup> and thus the main value of the series creation in this case is that definitions in ORS 469A.005 are applicable to the entire the Act to “operate together as a coherent whole.” The creation of the series does not indicate legislative intent to administer the whole series without more express language.<sup>9</sup>

**d) History behind the small-scale/community-based goal evidences that it was never part of an RPS.**

In the Renewable Energy Working Group (“REWG”), the Governor-appointed group that met through much of 2005 and 2006 to create the Act, the original 8% goal was a request of the “Community Caucus.” That caucus met as a side group to the REWG and issued a report to the REWG in July 2006. In their report,<sup>10</sup> the caucus stated that it “discussed an 8% carve-out setting aside a portion of a Renewable Portfolio Standard for community-scale renewable energy” but decided that policy was not “ideal for Oregon.” Instead, the caucus proposed a mix of actions<sup>11</sup> and the 8% goal that was drafted into the Act in 2007. In his report to Governor Kulongoski, the chair of the REWG, Mike McArthur, noted that the 8% goal was agreed to by the Community Caucus “in lieu of a carve out target”<sup>12</sup> wherein the small-scale requirement would have been

<sup>5</sup> See the Oregon Legislative Counsel drafting manual, section 13.2

<sup>6</sup> See Preface to Oregon Revised Statutes at viii,

<sup>7</sup> ORS 469A.200 provides that the Commission may impose a penalty against an electric company or ESS that fails to comply with a renewable portfolio standard in the manner provided by ORS 469A.005 to 469A.210. This is not the same as providing a penalty for failing to comply with the entire series. See, e.g., ORS 757.656 which provides: “any person injured by an electric company’s failure to comply with any provision of ORS 757.600 to 757.667 may file an action in the circuit court....”

<sup>8</sup> See, e.g., ORS 757.659, where the legislature directed the Commission to “adopt such rules as are necessary to implement ORS 757.600 to 757.667.”

<sup>9</sup> Compare, e.g., ORS 757.659.

<sup>10</sup> See REWG’s Community Caucus Report presented to the Oregon’s Renewable Energy Working Group July 11, 2006 (included as an attachment)

<sup>11</sup> E.g., constraining the public purpose charge renewable energy portion to projects less than 20MW and extending the public purpose charge funding through 2025

<sup>12</sup> See, McArthur letter dated March 23, 2007 (included as an attachment).

part of an RPS. Thus, not only does the explicit language of the Act show that the 8% goal is not part of an RPS, the history behind the provision shows that the proponents of the language discussed including the 8% as part of the RPS as a “carve out” but intentionally chose not to pursue that path, creating a goal along with other policy changes as the means to accomplish development of small renewable projects.

In summary, the Commission has explicit delegated authority to direct electric companies in the manner of their implementation of the renewable energy requirement imposed by an RPS. Because the legislature divided responsibility for implementing the Oregon Renewable Energy Act between two state agencies and the consumer-owned utilities, the Commission should not assume that it has implicit authority over any statute section that is found in the series ORS 469A.005 to 469A.210. The direction in *Coffey* is to “to discern whether the legislature nonetheless impliedly intended to require the agency to make rules concerning the subject matter in question.” Because the authority delegated related to an RPS and because ORS 469A.210 is not an RPS, PGE believes the legislature did not impliedly intend to allow the Commission to adopt rules through its general rulemaking authority in ORS 757.060 to effectuate ORS 469A.210 because there is no evidence that the Commission was directed to “administer” a requirement of the Oregon Renewable Energy Act that was not an RPS.

**2) The Legislature did not provide explicit authority to the Commission to adopt rules regarding ORS 469A.210.**

We now turn to the primary prong of the analysis required by *Coffey*, “If an agency is required to adopt a rule through rulemaking proceedings, that requirement must be found through an analysis of the specific statutory scheme under which an agency operates and the nature of the rule that the agency wishes to adopt.” *Coffey*, at 498.

**a) The Oregon Legislative Assembly did not provide explicit rulemaking authority for implementation of ORS 469A.210 to any agency.**

As mentioned above, the legislature provided specific direction within the Act to adopt rules at least five times within the original 24 sections of law. PGE does not find any specific direction to the Commission to adopt rules to implement the small-scale/community-renewables provision. On the other hand, PGE finds numerous explicit directions to the Commission to: adopt procedures for implementation of an RPS by electricity service suppliers; to adopt rules establishing requirements for creation of implementation plans; to adopt rules for allocating RECs for multi-state utilities; to adopt alternative compliance payment amounts; and to establish the revenue requirement to be used in calculation of the cost cap. In the context of the Oregon Renewable Energy Act, the legislature would have provided explicit rulemaking authority if it deemed it necessary for the statute to be implemented.

**b) The Oregon Legislative Assembly removed any explicit authority that the Commission had regarding ORS 469A.210 in adopting SB 1547 (2016).**

As ORS 469A.210 was originally adopted, it contained a provision that “[a]ll agencies of the executive department as defined in ORS 174.112 shall establish policies and procedures promoting the goal declared in this section.”<sup>13</sup> The legislature removed that sentence when it amended the section to change the statewide goal into a mandate in the -A18 amendments to Senate Bill 1547 (2016). Mr. Irion Sanger (representing the Renewable Energy Coalition and the Community Renewable Energy Association (CREA)) in letter comments dated April 9, 2018, in a different rulemaking proceeding regarding the RPS – AR 610 – stated that “the Commission appears to have ignored the specific direction that it establish policies and procedures promoting the goal.”<sup>14</sup> PGE assumes that these “policies and procedures” could have included rules, but this explicit authority was repealed when ORS 409A.210 was amended.

In the same session that the legislature repealed the direction to all state agencies, it also took no steps to clarify whether any state agency should receive implementing authority for the statute in the absence of that general direction. The new ORS 469A.210 is silent and the legislature must have understood that it was removing explicit authority.<sup>15</sup>

Senate Bill 1547 was the bill that ultimately passed in 2016, but the amendment work on that bill was done in the legislative debates over House Bill 4036. HB 4036 was “gut and stuffed” into SB 1547 and thus one must investigate the legislative history of that bill to understand what legislators understood about the amendments to ORS 469A.210. Highly relevant for the purposes of this discussion are the statements made by the proponents of the changes to ORS 469A.210. In submitted testimony by the Association of Oregon Counties,<sup>16</sup> Community Renewable Energy Association,<sup>17</sup> and Lake County,<sup>18</sup> all supporting the -A41 amendments that changed the goal to a mandate in ORS 469A.210, none mentioned that the Commission would acquire authority to enforce the provisions. In fact, no submitted testimony supporting the -A41 suggested adding specific authority for the Commission. Oral testimony in support of the community renewables change also does not support a reading of increased commission oversight. Brian Skeahan, then executive director of CREA, in the House Energy and Environment hearing on HB 4036 on 2/2/2016, merely suggested that the goal needed to be turned into a mandate to make it fair for smaller facilities to be able to compete against large-scale utility projects. Legislators were not presented with any request to amend Commission authority regarding this statute and PGE cannot find any evidence in the legislative record that they considered it when modifying ORS 469A.210 into a mandate.

**c) The legislature has declined on numerous occasions to provide explicit rulemaking or other authority to the Commission to implement ORS 469A.210.**

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<sup>13</sup> See Section 24, Senate Bill 838 (2007).

<sup>14</sup> See <https://edocs.puc.state.or.us/efdocs/HAC/ar610hac113357.pdf>

<sup>15</sup> ORS 174.020 (1)(a) provides that “in the construction of a statute, a court shall pursue the intention of the legislature if possible.” PGE argues here that the intention of the legislature is clear, explicit authority to establish policies and procedures was repealed for all state agencies and should not therefore be read into the statute.

<sup>16</sup> <https://olis.oregonlegislature.gov/liz/2016R1/Downloads/CommitteeMeetingDocument/88522>

<sup>17</sup> <https://olis.oregonlegislature.gov/liz/2016R1/Downloads/CommitteeMeetingDocument/88523>

<sup>18</sup> <https://olis.oregonlegislature.gov/liz/2016R1/Downloads/CommitteeMeetingDocument/88585>

Through four additional regular legislative sessions (excepting special sessions), the legislature has declined to provide explicit implementation authority for ORS 469A.210. During that time, the legislature has considered a score of bills or amendments that would have modified ORS 469A.210 to include explicit rulemaking authority for the Commission or would have made the statute section part of ORS chapter 757, thereby subjecting it to the “administration” of the Commission.

In 2017, the legislature considered a number of bills either amending ORS 469A.210 or modifying authority related to that statute. As noted above, it adopted SB 339 but in so doing did not consider, nor did any entity propose amendments, that would have modified explicit rulemaking authority vis-à-vis that statute. The legislature rejected HB 2136, a bill that would have increased the small-scale/community renewables delivery requirement and would have amended ORS 469A.200 to provide penalty authority to the Commission for failure to comply with the new provisions. That bill failed to make it out of committee.

After PGE questioned Commission rulemaking authority in this matter in the October 2018, REC and CREA sought to change ORS 469A.210 to provide the Commission with explicit rulemaking authority. At their request, the legislature introduced and considered House Bill 2857 in 2019 that, in part, added a new subsection (6) that provided “The Public Utility Commission shall adopt rules as necessary to implement this section.” The bill did not advance out of committee. Also in 2019, the legislature considered HB 3274, a bill that would have, in part, provided explicit rulemaking authority to the Commission. It too, failed to advance out of the first house, moving to Rules and remaining there until *sine die*.

In 2021, the legislature considered at least 16 amendments to House Bill 2021 that would have clarified that authority for implementation of ORS 469A.210 rested with the Commission.<sup>19</sup> Again legislators declined to adopt that change, leaving any such suggestion on the cutting room floor as it adopted changes again to ORS 469A.210.

We recognize that when interpreting statutes, inaction by the legislative branch lacks persuasive significance in most circumstances, because there can be many reasons why the legislative branch fails to act.<sup>20</sup> However, in this case, given the sheer volume of opportunities the legislature has had since 2016 to provide explicit authority to an agency, any agency, including through multiple legislative sessions, multiple bills, multiple proposed amendments and the two instances where the legislature actually took action to amend the section in 2017 and 2021, PGE believes inaction on this topic can be viewed in only one way: that the body is comfortable with the current regulatory structure that does not provide explicit authority for any agency to implement the statute.

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<sup>19</sup> These amendments were the -3, -6, -8, -10, -11, -17, -20, -24, -25, -26, -A32, -A35, -A36, -A37, -A38 and -A39 to HB 2021. PGE has not investigated amendments to other bills that may have also attempted to provide authority for the Commission to adopt rules and therefore this list may not be exhaustive.

<sup>20</sup> See, e.g., discussion of this topic in *Star Athletica, LLC v. Varsity Brands, Inc.*, 137 S. Ct. 1002 (2017); *Pension Ben. Guar. Corp. v. LTV Corp.*, 110 S.Ct. 2668 (1990).

## **II. Authority of Commission and of ODOE to ensure that electric companies are meeting the requirements of ORS 469A.210**

Our position regarding Commission rulemaking authority notwithstanding, PGE is working diligently to ensure that it meets the requirements of the self-implementing requirement of ORS 469A.210. As reported to, and published by, ODOE during the 2021 legislative session, PGE currently has 409 MW of small-scale renewable energy projects providing energy to our customers and another 403 MW of small scale renewable energy projects that could be operational over the next few years. Since at least 2015, PGE has worked cooperatively with ODOE on a biennial basis to develop and produce reports specifying our progress toward meeting the mandate. We have provided detailed information on production of energy from owned and contracted facilities that meet the requirement and believe that this information is useful to the public in determining whether we are meeting the original intent of the Community Caucus. We will continue to dedicate time and energy toward this effort regardless of the outcome of this rulemaking.

Finally, PGE has concerns that the proposed pared-back rules accomplish little that could not be accomplished through other processes. The Commission has plenary authority to supervise and regulate utilities under ORS 756.040 and has the ability to open investigations under ORS 756.515 (1) under “any matter relating to any public utility.” Within such an investigation, the Commission could request that PGE show its progress toward meeting the standard expressed in ORS 469A.210 and take testimony or receive other information that is the subject of the proposed rules. In fact, PGE has been quite open regarding our progress toward compliance with the standard and has already submitted detailed information regarding compliance in filings in this docket,<sup>21</sup> in addition to data periodically supplied to ODOE. PGE will continue to provide data, as requested by the Commission and ODOE, to show our compliance leading up to the 2030 compliance date expressed in ORS 469A.210.

PGE requests that the Commission close this docket without adopting the proposed rules.

## **III. PGE comments on the proposed rules**

Notwithstanding PGE’s comments in the preceding paragraphs regarding the authority of the Commission to adopt rules, if the Commission determines that it does have rulemaking authority, PGE would ask that the Commission consider the comments below.

PGE is supportive of the direction of the rules as compared to the proposed rulemaking filed December 27, 2018. Specifically, as compared to the 2018 rules, we support the removal of the requirement: (1) for the utility to own the renewable attributes from a project for the project to count towards compliance; (2) for projects to be located in Oregon for the project to count towards compliance; and (3) for the utility to address their small-scale renewable energy project compliance status and plans in RPS Implementation Plans. We addressed the reasoning behind these necessary and important proposed rule changes in our written comments made in this

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<sup>21</sup> See <https://edocs.puc.state.or.us/efdocs/HAH/ar622hah172322.pdf>

docket on November 29, 2018 and February 21, 2019 and we incorporate those comments here by reference.

Even with the improvement to the proposed rules, as compared to the 2018 rules, further refinement is necessary if the Commission moves forward with adopting rules.

### **1. Rule 860-090-0030 Eligible Renewable Energy Projects**

As proposed, Rule 860-090-0030 states “Projects used to comply with the standard in ORS 469A.210(2) must be an Oregon Renewable Portfolio Standard-approved generator.” PGE is opposed to this language as the plain reading of the statute, subsection (2)(a), clearly defines the metes and bounds for project eligibility. They are: (1) facilities up to 20 megawatts (MW) in capacity; and (2) utilizing a *type* of energy contained in ORS 469A.025; or (3) certain biomass projects that also generate thermal energy for a secondary purpose. Project eligibility based on satisfying these requirements results in a clear and straightforward verification process, but the statute does not require a project to be an “Oregon Renewable Portfolio Standard-approved generator.”

The requirement of ORS 469A.210 is not to take qualifying energy from facilities - that requirement would be created by a reference to ORS 469A.020 - but instead to take energy of a *type* that can potentially generate qualifying electricity if other criteria are met, such as age of the facility. The language in ORS 469A.025(1) is instructive: "Electricity generated utilizing the following types of energy may be used to comply with a renewable portfolio standard" - solar, wind, hydro, wave, geothermal, etc., can all be used. The legislature, through ORS 469A.210, sought to promote small-scale and combined heat and power biomass energy generation. The "renewableness" of the project is determined by its type, not whether it went through the certification process to become an “Oregon Renewable Portfolio Standard-approved generator.” Pursuant to our interpretation, the acquisition of null power from a small scale facility could be used to meet the standard, acquisition of energy from a facility that declines to register as an “Oregon Renewable Portfolio Standard-approved generator” would qualify, a small-scale generator that was built prior to 1995, thus prohibited from registering as an “Oregon Renewable Portfolio Standard-approved generator” unless it is low-impact hydroelectric, would also qualify, and community solar and net metered projects could be used to meet the standard. All these projects meet the project eligibility criteria in ORS 469A.210(2) which creates a simple two-pronged test to determine project eligibility.

Additionally, PGE is opposed to CREA’s and OSSIA’s proposed language changes to Rule 860-090-0030 that they filed in their written comments on October 13, 2021. PGE supports the removal of the requirement that qualifying projects must be located in Oregon and the utility attribute-ownership requirements to comply with ORS 469A.210 and ORS 469A.210(2).

### **2. Rule 860-091-0040 Compliance Reports**

As mentioned in previous filed comments made in November 2018 PGE believes the use of “compliance” in Rule 860-091-0040 is outside the scope of the authority provided to the

Commission by the legislature. PGE suggests revising this language to indicate a “status report” filing with the Commission for demonstrating progress toward the standard rather than compliance.

But more importantly, the statute is clear as to the time period of compliance (as 2030 and no further). The unambiguous language in ORS 469A.210 requires compliance “by the year 2030.” The proposed rules, however, require a compliance report by July 1, 2029, and every year thereafter. This requirement is not supported by the language in the statute. Also, the legislature will affirmatively state its intent when establishing an ongoing requirement. As an example, the RPS for large utilities is explicit in the requirement for compliance to continue beyond a particular date as ORS 469A.052(2)(h) states “At least 50 percent of the electricity sold by an electric company to retail electricity consumers in the calendar year 2040 and subsequent calendar years must be qualifying electricity.” The legislature did not include such an affirmative statement in ORS 469A.210(2).

PGE appreciates the hard work of Commission Staff and the Administrative Hearings Division to draft the proposed rules. Should you have any questions regarding these comments, please contact Brendan McCarthy at 503-464-7371. Please direct all formal correspondence and requests to the following email address [pge.opuc.filings@pgn.com](mailto:pge.opuc.filings@pgn.com).

Sincerely,

*/s/ Jay Tinker*

Jay Tinker  
Director, Rates & Regulatory Affairs

# **REWG's Community Caucus Report**

Presented to Oregon's Renewable Energy Working Group, July 11<sup>th</sup>, 2006

The REWG should make recommendations to the Governor that pursue the benefits of both large-scale generation systems (like central station wind or geothermal) and community renewables (like solar, biomass, small hydro, geothermal and community wind). Neither approach by itself will achieve the optimal outcome of a sustainable energy system with broad statewide support.

## ***Importance of Community Renewables***

1. Community Renewables diversify Oregon's energy portfolio, providing increased system stability and reliability, and improved energy efficiency and environmental benefits.
2. Community Renewables create enhanced economic opportunities throughout Oregon and keep more energy dollars within the state.
3. Community Renewables keep Oregon competitive in emerging renewable energy industries.

## ***Proposed Necessary Actions by the Legislature***

1. Focus the renewable energy portion of the Public Purpose Charge (PPC) on funding a mix of community projects of 20 MW or less. Require the OPUC to ensure that implementation of PPC programs reflects this change in focus.
2. Endorse the OPUC's Legislative Concept to extend the PPC funding through the year 2022 or extend the PPC funding through 2025 to be consistent with the RPS policy.
3. Endorse the OPUC's Legislative Concept to authorize the OPUC to increase the PPC funding beyond the current 3% to provide more funding for renewables (currently at 0.51 percent) without taking money away from valuable energy efficiency projects. Furthermore, the 3% should be set as a floor below which the PPC should not be reduced.
4. Propose an Oregon version of the PURPA-type requirement that utilities have to purchase the power from projects of qualifying renewable projects of 10 MW or less using standard contracts, and over 10 to 20 MW using non-standard contracts. Such requirements would be regulated by the OPUC.
5. Require the OPUC to modify policies and procedures as appropriate to meet a goal of generating at least 8% of Oregon's electricity from a mix of community renewables by 2025.
6. Establish statewide uniform interconnection and enhanced net metering standards.

## ***Process***

The Community Caucus met extensively to discuss major barriers to significant development of community-scale renewable energy, as well as various policy changes to address those barriers. The Caucus considered several major policy concepts that would be new policy directions for Oregon. We discussed an 8 percent carve-out setting aside a portion of a Renewable Portfolio Standard for community-scale renewable energy, as other states have used, with a separate cost cap from the overall RPS cost cap. We also considered an advanced renewable tariff (ART), as European countries have used. The Community Caucus believes that neither policy is ideal for Oregon. Instead, we are proposing an Enhanced Public Purpose Charge consisting of incremental changes to the existing Public Purposes Charge (actions 1-3) combined with 3 other necessary actions (actions 4-6).

Date: March 23, 2007  
To: Governor Ted Kulongoski  
From: Mike McArthur, Chair of the Renewable Energy Working Group  
RE: Progress Report from the Renewable Energy Working Group

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You charged the Renewable Energy Working Group (REWG) with developing implementation strategies for *Oregon's Renewable Energy Action Plan*. The Plan, which was finalized in April 2005, includes goals to encourage the growth and development of renewable energy resources and technologies in the state of Oregon. The Plan's ultimate goal is to encourage and accelerate the sustainable production of energy from renewable resources, stimulate economic development, particularly in rural parts of the state, and improve the environmental future of the state. In the Plan, there are specific tasks that are designated for the REWG to consider, as well as tasks for other state agencies and Oregon universities.

The REWG began meeting in February 2006, with a membership comprised of 31 stakeholders and four legislators with interests in energy. The REWG representatives are affiliated with a broad range of stakeholder groups including: utilities, academia, industry, environmental advocacy, and agriculture.<sup>1</sup> Additionally, Oregon's congressional liaisons and staff from related state and federal agencies have attended and participated in the group's meetings.

This is a report of the activities and accomplishments of the REWG over the past year:

- The group met monthly across Oregon, including meetings in Portland, Bend, Eugene, Hood River, Newport, and Salem. The REWG received comments from interested members of the public at their meetings. Additionally, a website was maintained through the Oregon Department of Energy (ODOE) which contained information and recordings from the meetings.
- The group conducted an initial prioritization of the 50+ tasks that were specifically delegated to the REWG. Fifteen of the tasks were general renewable energy items and the rest related to specific renewable energy technologies. They also discussed the information needed in order to inform their deliberations.
- The REWG spent months discussing elements of an RPS for Oregon and working on an outline of a renewable portfolio standard (RPS) proposal for the Governor, which was their top priority task. The REWG was briefed by Dr. Ryan Wiser, a leading expert on RPS development from the Lawrence Berkeley National Laboratory, to begin their discussions. The REWG's work and deliberations on an RPS has formed the basis of your RPS legislation that is currently being brought before the Legislature. REWG members were not in complete agreement on all components of the RPS; however each of those issues is clearly outlined in the attached status report.<sup>2</sup>
- Subcommittees and discussion groups were formed in the areas of biofuels, economic incentives, cost cap aspects of the RPS, and community-scale renewables. These groups met to discuss your legislative proposals and made recommendations to the REWG. These subcommittees and discussion groups include:

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<sup>1</sup> Appendix A contains a list of the current REWG members.

<sup>2</sup> The February 8, 2007 Status Report for the REWG Debate on Oregon's Renewable Portfolio Standard is attached as Appendix B and describes the key concepts within the RPS proposal.

- The biofuels subcommittee worked on your legislative proposal to increase the production and use of biofuels in Oregon. The success that this proposal has had in the Legislature can be traced, in part, to the relative consensus on many issues that this subcommittee's work was able to generate
  - The economic incentives subcommittee met to discuss the Business Energy Tax Credit (BETC) and Residential Energy Tax Credit (RETC) programs and how your legislative proposals to improve these programs could be further enhanced. Their efforts helped to build a general consensus among REWG members that led to their endorsement of both of these proposals.
  - The "Community Caucus" focused on community-scale renewables and policy elements of the RPS that would encourage the development of a wide diversity of renewable energy sources. This discussion group also debated net metering policy and other policy barriers.
  - A small group was also formed to discuss the cost cap provisions of the RPS in detail. This "cost cap" discussion group came to consensus on some basic principles of cost cap design that helped generate final language in the RPS bill.
- Presentations from experts in the fields of renewable energy were delivered to the group. Topics included: RPS design issues and potential policy alternatives, cost comparisons of fossil and renewable energy sources, net metering policy, utility integrated resource planning, and the benefits of small-scale renewables.
  - Additionally, the REWG communicated with specialized renewable energy working groups serving Oregon. These groups are working on many of the resource specific tasks designated in the Plan. Key highlights of their interaction with the REWG included:
    - February 2006: the REWG was briefed by Oregon's Wind Working Group, Geothermal Working Group, and Biomass Coordinating Committee, as well as ODOE staff working on solar and biofuels activities.
    - April 2006: the REWG considered and adopted six additional solar policy tasks that were presented by the Oregon Solar Coalition.<sup>3</sup>
    - January 2007: the Forest Biomass Working Group prepared a report and presentation to the REWG that identified obstacles and opportunities in biomass development for Oregon.
    - March 2007: the REWG adopted 11 key follow up action items from the Forest Biomass Working Group report in order to help support biomass utilization.<sup>4</sup>
  - The REWG discussed net metering and developed suggestions for Oregon's net metering process in a letter that was transmitted to the Oregon Public Utility Commission.<sup>5</sup> While not unanimously supported, and thus not representing a consensus of the REWG, a majority of REWG members endorsed the letter.

Over the past year, the REWG worked on seven of the 15 cross-cutting tasks delegated to them in the Plan. A tremendous amount of time and energy was devoted to the largest task, the development of an RPS. In the upcoming months, the REWG will reassess and prioritize future tasks to accomplish and oversee from the Plan. The REWG will continue to coordinate with the other working groups and encourage collaboration and a partnership of efforts related to renewable energy.

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<sup>3</sup> The Solar Policy Tasks are listed in the document attached as Appendix C.

<sup>4</sup> Appendix D contains the recommended forest biomass action items adopted by the REWG at the March 13, 2007 meeting.

<sup>5</sup> The letter to the PUC on net metering is attached as Appendix E.

## Appendix A Membership of the Renewable Energy Working Group (REWG)

**Legislators:** Sen. Kate Brown, Rep. Jackie Dingfelder, Sen. Ted Ferrioli, and Rep. Patti Smith

**Chair of the REWG:** Mike McArthur, Executive Director of the Association of Oregon Counties

Name	Affiliation	Title
Kevin Banister	Finavera Renewables	Director, Business Development
Jeremiah Baumann	Oregon State Public Interest Research Group	Environmental Advocate
Ted Bernhard	Stoel Rives LLP	Attorney, Technology Ventures Group
Jeff Bissonnette	Citizens' Utility Board of Oregon	Director, Fair & Clean Energy Coalition
Julie Brandis	Associated Oregon Industries	Legislative Representative; Energy
Barbara Byrd	AFL-CIO	Secretary-Treasurer
Kyle Davis	PacifiCorp	Environmental Policy Manager
Angus Duncan	Bonneville Environmental Foundation	Executive Director
Michael Early	Industrial Customers of Northwest Utilities	Executive Director
Bill Fashing	Oregon Economic Development Association	Board Member, Past President
Katie Fast	Oregon Farm Bureau	Associate Director of Governmental Affairs
David Shaw	Oregon Rural Electric Cooperative Association	Manager of Regulatory Affairs
Troy Gagliano	Renewable Northwest Project	Senior Policy Associate
Don Godard	Oregon People's Utility District Association	Executive Director
Michael Grainey	Oregon Department of Energy	Director
David Hackleman	Oregon State University	Linus Pauling Chair, Chemical Engineering
Cylvia Hayes	3E Strategies (Business Alliance for Sustainable Energy)	Executive Director
Jim Lobdell	Portland General Electric	Vice President, Power Operations and Resource Strategy
John Lund	Oregon Institute of Technology	Director, Geo-Heat Center
Jim Manion	Warm Springs Power Enterprises (Confed. Tribes of Warm Springs)	General Manager
Bob Maynard	Energy Outfitters	President/Founder
Carlos Reichenshammer	Reichenshammer Building & Design	President, Oregon Homebuilders Association
Tucker Ruberti	Idatech	Market Development Manager
Chris Taylor	Horizon Wind, Northwest Office	Director of Development
Jim Walls	Lake County Resources Initiative	Executive Director
Dick Wanderscheid	The City of Ashland Electric Department	Electric & Telecommunications Director
Peter West	Energy Trust of Oregon	Director of Renewable Energy Programs
Jonathan Williams	Intel	Government Affairs Manager
Scott Winkels	League of Oregon Cities	Staff Associate
Paul Woodin	Community Renewable Energy Association	President

**Governor's Representative to the REWG:** David Van't Hof, Governor's Sustainability Advisor

(3/12/2007)

**Status Report: REWG Debate on Oregon’s Renewable Portfolio Standard**

**Targets**

Summary of Key Concepts	Areas of Agreement	Areas of Disagreement
General Structure	General consensus that use of RECs for RPS compliance is acceptable.	Some are fundamentally and philosophically opposed to the RPS or similar style mandates. Thus such disagreement would extend to every box below and the policy as a whole.
The proposed renewable portfolio standard (RPS) for Oregon consists of three separate standards, tied together by a common set of implementation and compliance parameters that are based on the use of Renewable Energy Certificates (RECs) to serve as the compliance mechanism for the RPS. All utilities in Oregon would be subject to a primary or secondary standard, and Electricity Service Suppliers would have a related standard.		
Primary Standard for Utilities	Most seem to agree that using percentage of retail sales as the metric of RPS applicability is acceptable.	Where threshold for RPS applicability should fall: Lower limit: ½ percent Upper: limit 5 percent.  Number of “hard” targets: Lower limit: none Upper limit: every year  Some would like standard to be load growth only.
Those utilities that are responsible for one percent or greater of total retail electric sales in Oregon would be required to ensure that by 2025 and beyond at least 25 percent of their retail sales come from renewable sources. Similarly, interim targets are set for 2011, 2015, and 2020 at 5, 15, and 20 percent, respectively. The target level remains in effect each year until the next target becomes effective, creating a minimum floor for compliance.		
Secondary Standard for Utilities	Most seem amenable to the “lesser burden of ” concept to avoid unwanted interaction effects between the Primary and Secondary standards (i.e., the burden of the Secondary surpassing that of the Primary in later years)	Some question need for Secondary standard.  60 percent of retail sales growth considered too high by some.
Utilities responsible for less than one percent of total retail electric sales in Oregon would be required to meet the lesser burden of having either 60 percent of any growth in retail sales or 25 percent of their total retail sales come from renewable sources by 2025 and thereafter. To begin with in 2015 these utilities would be required to meet the lesser burden of having either 20 percent of growth in retail sales or 15 percent of their total retail sales come from renewable sources by 2015 and each year after until 2020. Similarly, by 2020 these utilities would be required to meet the lesser burden of having either 40 percent of growth in retail sales or 20 percent of their total retail sales come from renewable sources by 2020 and each year after until 2025.		
Standard for Electricity Service Suppliers (ESSs)	ESSs should be subject to a standard that creates a “level playing field” between utilities and ESSs in Oregon.	Some not sure of feasibility of implementing standard in this manner.
ESSs are required to ensure that in each year the RPS is in effect the amount of their retail sales that come from renewable sources is equal to an amount that is calculated as if each of the ESS’s customers were instead being served by their applicable utility based on the service territory in which those customers reside. Thus, this summation of retail sales obligations may include a mix of amounts from both the primary and secondary standards.		
Federal Base System (FBS) Firm Power Exemption	General consensus that preference rights to firm FBS BPA power should not be lost due to RPS obligations.	Belief that the same guarantee should extend to non-firm BPA power. Concern about slice customers.
If RPS requirements would unavoidably displace firm FBS power preference rights for a consumer-owned utility in a given year then the obligation for that utility is reduced proportionally by an amount equal to that unavoidable displacement of power.		

<b>RPS Obligations in Excess of Load Growth</b>	Most seem to agree with the principle behind this provision.	Belief that only the second clause of this provision (regarding displacement of non-fossil fueled resources) should apply.
If the primary standard results in a utility having no other choice but to acquire power resources in excess of their load growth in a compliance year, and if the RPS obligation would result in the displacement of a power resource other than a fossil-fueled resource by the utility, the requirement for that compliance year is reduced by an amount up to such displacement.		
<b>Mid-Columbia Hydropower Obligation Deferment</b>	Most seemed to accept logic that this situation is substantially similar to BPA power and deserves consideration.	Belief that the same deferment opportunity should extend to IOUs.
For those consumer-owned utilities that have low-price hydro contracts with the Mid-Columbia non-federally owned dams the RPS obligation for a given year is reduced by an amount equal to the amount of power obtained under said contracts until those contracts are no longer in effect, or until those contracts can't be renewed at a substantially similar low-cost power rate.		
<b>Cost Cap Off-Ramp Provision</b>	General consensus that cost cap provision is an essential element to the RPS. Some agreement on very basic elements of cost cap structure.	Disagreement on retail revenues vs. power costs, need for additional cost effectiveness test, cost cap percentage, and a long list of other issues.
Utilities need only comply with the renewable portfolio standard in a given year up to the point where they expend a percentage (proposed as 4 percent) of their RPS-applicable portion of annual revenue requirements on the costs of RPS compliance.		
<b>Movement From Secondary Standard To Primary Standard</b>	Most seemed to agree to this provision.	
When a utility that was responsible for less than one percent of Oregon's total retail electric sales increases its share of those sales to one percent or more, then that utility becomes subject to the primary standard. However, its burden under the RPS is calculated under a timeline adjusted such that it has the same ramp-up of obligations as if it had been in the primary standard since the start date of the RPS program.		

## Resources

<b>Date of Eligibility</b>		Some would prefer no date, i.e., all qualifying resources eligible. For those that agree a date makes sense the range is: Lower limit: 1981 Upper limit: 1999
Generating facilities using qualifying renewable resources must have been placed into operation on or after January 1, 1995.		
<b>Facility Location</b>	The geographic eligibility for the Oregon RPS need not extend beyond WECC.	Many would prefer it be limited to Pacific NW, others would like Oregon-only to the extent feasible.
Facilities using qualifying renewable resources must physically reside in the geographic boundaries identified by the North American Electric Reliability Council (NERC) Western Electricity Coordinating Council (WECC) region.		
<b>Standard RPS Resources</b>	General consent seemed to exist for all of these resources at the Eugene REWG meeting.	
Electricity generated from wind, solar photovoltaic, solar thermal, wave, tidal, ocean thermal, and geothermal would all be RPS eligible.		

Incremental or Proportionate Resources	After modifications, most seem OK with these resources.	Some would like efficiency and conservation measures to count as resources in RPS.
Both the renewable proportion of a multi-fuel generation process and the incremental improvement to a qualifying renewable energy generating unit (non-hydro) made through capital improvements after the qualifying date would be eligible.		
Hydrogen and Fuel Cells	Most seem OK with this resource given the qualifications.	Some would like fuel cell use to not be dependent on renewable sources.
Electricity generated from the use of hydrogen reformed from or electrolyzed entirely from qualifying renewable resources would be eligible. The use of fuel cells, in and of themselves, would not necessarily qualify unless the hydrogen fuel in use qualified.		
Biomass and Biogas Resources	Most seem to agree with those resources described by the first sentence. General consensus with biogas range of inclusions.	Many disagree on including spent pulping liquor and/or excluding MSW combustion. Concern about the lack of sustainability criteria. Some question feasibility of excluding treated wood
Includes biomass and byproducts from organic human or animal waste; solid organic fuels from wood, forests, and field residues; and dedicated energy crops. Includes spent pulping liquor. Includes biogas from organic sources, wastewater, anaerobic digesters, and municipal solid waste (e.g. landfills). Does not include wood treated with chemical preservatives or municipal solid waste combustion.		
Hydropower	General agreement that low-impact hydro should qualify.	Disagreement about nearly all aspects of what type of limits on hydropower to include.
Any hydroelectric facility not located in a federally-protected area in effect upon the enactment of SB 1149, i.e., not on a river or stream area listed by the Northwest Power and Conservation Council as protected or considered a Wild and Scenic River by Congress.		
Incremental Improvements to Hydropower Facilities	Most seem to agree that hydro efficiency projects should be included to some degree.	Disagreement as to whether BPA dam projects should be included, as well as on amount of projects that should be eligible. Problems with proportion calculation noted by some.
The increment of improvement resulting from an efficiency upgrade to an existing hydropower facility, completed after the qualifying date, would qualify but there would be an upper limit on the use of BPA efficiency projects based on the proportion of FBS power that Oregon COU's receive relative to the total amount (i.e, from WA/ID/MT).		
Determination of Additional Qualifying Resources		Some feel that additional resource determination should be left to legislature.
An ODOE rulemaking procedure will be established to add new resources as necessary to the eligibility list for the RPS. Under no circumstances, however, will electricity derived from fossil fuel resources, nuclear, or the combustion of municipal solid waste be considered an eligible resource under the RPS.		
BPA Renewable Energy Product	Most agree that allowance should be made for BPA EPP-type product.	
Irrespective of any delivery requirement, Oregon RPS-qualifying RECs associated with BPA Environmentally Preferred Power (EPP) or a substantially similar product from BPA ("Tier II Renewable Product") would be eligible for the RPS.		

## Renewable Energy Certificates

Use of Renewable Energy Certificates (RECs)	No disagreement on using WREGIS system.	
REC verification and tracking will come from the Western Renewable Energy Generation Information System (WREGIS).		

Timing of Bundled REC Creation	Most seem amenable to accepting this definition, along with the implications for allowing shaping and firming resources.	
A bundled REC is considered to be created at the point when qualifying renewable power hits the first point of interconnection with the BPA control area, the Northwest Power Pool (NWPP) control area, or any Oregon RPS-obligated utility's transmission system. This has important implications for shaping and firming resources, as it allows unlimited substitution of the power component of a bundled REC as it makes its "journey" from that first point of interconnection to an Oregon RPS-obligated utility.		
Usage of Unbundled RECs for Compliance	Most seem OK with the inclusion of some level of unbundled RECs	Geography: WECC vs. Pacific NW (noted above)
No more than 20 percent of compliance within a given compliance year for the Primary standard can be met with unbundled RECs, but these RECs can come from anywhere within the WECC. No upper limit exists for the Secondary or ESS standard. Exemptions for certain RECs from smaller projects can raise the upper limit.		Upper limit: Some want unlimited, others closer to 5 to 10 percent limit
Usage of Bundled RECs for Compliance	Most seem comfortable with WECC region for bundled RECs as an outer boundary.	Some would prefer to get rid of delivery language and simply base eligibility on physically located within WECC.
Bundled RECs will comprise the majority of compliance with the RPS. Eligible bundled RECs derive from facilities located with the WECC and that deliver power to Oregon RPS-obligated utilities through a path involving the BPA control area, the Northwest Power Pool (NWPP) control area, or any Oregon RPS-obligated utility's transmission system, or a combination of the above systems.		
RECs Funded from the Public Purpose Charge	General consensus (once this got fixed) seems to exist on this.	
In cases where RECs derive from projects funded by the public purpose charge and are then retired on behalf of ratepayers those RECs will be credited to the utility serving those ratepayers.		
RECs from Small-Scale Renewable Energy Projects	Most seem OK with this.	Some believe that Oregon-only part of language might cause legal issues.
The ceiling on unbundled RECs is raised by one MWh for each bundled REC purchased from a PURPA "qualifying facility" located in Oregon. Unbundled RECs from WREGIS-qualifying off-grid and customer-sited resources located in Oregon are RPS eligible and also exempt from the ceiling on unbundled RECs.		
RECs from Voluntary Green Energy Utility Programs	Most seem OK with Gov's Office idea of "returning" RECs from state facilities back to utilities for RPS use.	Disagreement as to whether such policies may be applied to COUs.
RECs obtained by utilities and used to satisfy voluntary retail green pricing tariff programs ("green power programs") are not eligible for RPS compliance. RECs transferred to customers by such a program may, at the customer's sole discretion or through voluntary contract, be transferred back to the utility for RPS use.		
REC Integrity	Most seem OK with these concepts.	
RECs used for the Oregon RPS can't be used for other states' RPS programs. No disaggregation (removing one or more individual attributes) of RECs is allowed. In future legislation mechanisms will be devised to allow RECs used for compliance with the Oregon RPS to comply with any potential carbon cap legislation that emerges.		
Multi-state Allocation of RECs for RPS Compliance	Unknown.	
For a multi-state IOU decisions on the share of bundled RECs allocated to Oregon will reflect the above-market costs paid by Oregon ratepayers and a fair allocation of RECs for market (or cheaper) cost purchases as determined by OPUC proceedings.		

## Compliance

Route of Compliance		
Utilities and ESSs request that RECs be retired in the WREGIS system to achieve the desired level of annual compliance.	Most seem to be fine with use of WREGIS.	
Flexibility in Reaching Annual Compliance		
RECs may be retired up to 90 days past the year in which they are intended to satisfy compliance, and may be banked for an unlimited amount of time. However, banked RECs must be retired on a first in, first out (FIFO) basis so that the oldest RECs being banked are used prior to any newer RECs being used.	Most seem fine with 90 day “true up” period.	Some believe that a “shelf life” (i.e., a time limit on the use of RECs) should be put on banked RECs.
Minimum Level of Annual Compliance for Primary Standard		
Each utility must retire enough RECs every year to satisfy the target in effect for that year. At a minimum, enough RECs must be retired to meet the last interim or final target in effect or the interim or final target that goes into effect that year. This “step function” creates a minimum floor of compliance for utilities.		
Minimum Level of Annual Compliance for Secondary Standard		
Each utility must retire enough RECs to meet their obligation as determined by the percentage target in effect that year and the increase in retail sales (if any) for that utility during that year.		
Minimum Level of Annual Compliance for ESS Standard		
Each ESS must retire enough RECs to meet their annual burden as determined through the aggregation of their customer’s relevant utility obligations as described in the target section.		
Filing of Compliance Plans		
Each utility must submit a compliance plan every two years to ODOE (for COUs) or OPUC (for IOUs and ESSs) that specifies exact “soft” targets above the minimum compliance floor for which the utility will strive to achieve. For IOUs this reporting process will be aligned with IRP protocols to the extent possible.		Disagreement as to whether COUs should have to submit compliance plans.
Compliance Letter		
All utilities and ESSs will submit a letter to ODOE (for COUs) or OPUC (for IOUs and ESSs) noting their level of compliance for a given year and any reasons for not meeting either the minimum level of compliance or a “soft” target for a given year.	Most agree that a notification on whether a utility has complied or not is reasonable.	Disagreement as to whether ODOE should require compliance letters from COUs.
Compliance Determination		
After submission of the compliance letter ODOE (for COUs) or OPUC (for IOUs and ESSs) will make a determination as to whether the utility or ESS is in compliance for a given year.		Disagreement as to whether ODOE should have the right to make such determinations.

## Compliance Shortfalls

<u>Option 1: Alternative Compliance Payments</u>		
Alternative Compliance Payment Mechanism		Inclusion of the alternative compliance payment mechanism is highly controversial.
If alternative compliance payments are included as a mechanism then any shortfalls in compliance using RECs could be addressed by paying a dollar per MWh payment total to a designated entity (or into a special fund) to be used for acquiring eligible resources in the future.		
Designation of Alternative Compliance Payment Amount		For those that support the alternative compliance payment mechanism, there is a large degree of debate as to where the level should be set.
The alternative compliance payment amount would be an amount higher than, and indexed to, the incremental costs associated with eligible resources, as determined by the PUC or the applicable governing body for consumer-owned utilities.		
<u>Option 2: Penalties</u>		
Penalty Determination for Primary Standard	Most seem OK with idea of applying 3-year average before making penalty determination.	Concern with delay involved if the 3-year average test is used.
Penalties are only applied if the compliance determination finds that the minimum floor of compliance is not achieved in a given year between targets or, for each interim target year and beginning with the final target year, after an additional three-year averaging test is applied and the results of that average also indicate a level of compliance below the target for that year.		Disagreement about penalties for COUs.  Some support alternative compliance payment scheme in lieu of penalties.
Penalty Determination for Secondary and ESS Standard		Disagreement about penalties for COUs.
If a utility or ESS is found not to have retired sufficient RECs to be in compliance in a given year then penalties will be applied		Some support alternative compliance payment scheme in lieu of penalties.
Penalty Amount and Appeal Process	General consensus that penalties, if used, should be non-recoverable.	Disagreement as to amount of the penalty and the applicability to COUs of such penalties.
A penalty of \$45 per MWh of shortfall will be assessed on any utility or ESS deemed out of compliance after the appropriate test. This penalty will be non-recoverable in rates for IOUs. A penalty hearing process will be created through rulemaking so that in exceptional hardship cases penalties may not be applied.		
Penalty Recipient	Most seem to agree that it is fine for IOU penalties to go to PPC entity.	Disagreement on dispatch of COU penalties to third party entity.
Penalties from IOUs will be paid to the NGO sub-contracted to the OPUC to manage public purpose charge funds and used for renewable energy projects. Penalties from COUs will be paid to a similar entity (to be determined through rulemaking by ODOE) for renewable energy projects in consumer-owned utility territory or territories.		

## Task Force

Periodic Task Force	Most seem to agree that some sort of feedback mechanism is appropriate.	Some disagreement about timing and scope of authority.
A task force will be convened by the Governor after each of the Primary interim target years to evaluate the RPS and report back to the Legislature if there are items that need to be addressed.		

## Public Purpose Charge

Renewable Energy Component of the Public Purpose Charge	Community Caucus agreed to this provision (among others) in lieu of a “carve out” target for small-scale renewable energy.	Some do not feel this should be part of RPS. Some think 20 MW is too big.
Focus the renewable energy portion of the Public Purpose Charge on funding a mix of projects of 20 MW or less and exclude funding of projects larger than 20 MW. Require as part of this statute that the OPUC will ensure that implementation of public purpose charge programs reflects this change in focus.		
Extension of the Public Purpose Charge (PPC)	Part of Community Caucus agreement.	Disagreement as to whether PPC should be extended to any degree.
Extend the public purpose charge through 2025 so that the PPC will be consistent with and serve as a complement to the RPS policy to promote a diversity of renewable energy sources.		

## Related Energy Policy

Cost Recovery for Investor-Owned Utilities	General consensus that this seems reasonable.	Concern about cost recovery aspects of early-stage renewable development activity.
Compliance with the RPS is not considered an above-market cost as defined in ORS 757.612(1). In addition, all prudently incurred costs associated with RPS compliance are recoverable under the RPS, including those associated with transmission and delivery of renewable energy to customers in Oregon.		
Mandatory Green Power Program for all Utilities		Disagreement as to necessity and desirability of such a mandate.
All utilities will be required to offer a voluntary green power purchasing program to their customers. Program details are largely left to the discretion of the utility		
State PURPA Reinstatement	Part of Community Caucus agreement.	Disagreement as to whether this should be part of package.
Modify ORS 757.612 (4) to require PGE and Pacific Power to meet state PURPA Statute ORS 758.505 to 758.555.		
Non-binding Goal for Community Energy	Community Caucus agreed to this provision (among others) in lieu of a “carve out” target for small-scale renewable energy.	Disagreement as to whether goal is necessary or appropriate. Arguments about semantics in regard to the word “goal”.  Some support multiplier for small-scale projects.
A non-binding goal will be included in the RPS that at least eight percent of Oregon’s retail sales should come from a mix of small-scale renewable energy projects by 2025. Direction to state agencies to try and help achieve this goal through appropriate policies and programs would also be included.		
Changes to ORS for People’s Utility District RPS Compliance	No objections noted at Portland meeting when the group was queried.	
1) Authority to operate on REC market. 2) Revise ORS to exempt renewables from cost effective test. 3) PUDs eligible for renewable energy development zones. 4) Change various facets of public voting for PUDs. 5) Change various facets of financing for PUDs. 6) Change taxations status for PUD partially owned projects. 7) Change public contracting requirements for renewables. 8) Allow PUDs to participate in Joint Operating Agencies. 9) Allow PUDs to form LLC’s for renewables development. 10) Revise ORS regarding PUD’s and judicial validation.		

# Solar Policy Tasks

Recommendations for the Renewable Energy Working Group  
by the Oregon Solar Coalition

This document was developed by in consultation with the members of the Oregon Solar Coalition to provide the Renewable Energy Working Group (REWG) with a short list of key steps that should be taken to advance solar photovoltaic (PV) and solar thermal (ST) businesses in Oregon. The REWG should consider to take action on each of the following items.

## ***1. Workforce Development***

The combined efforts of the Energy Trust of Oregon (ETO) and the Oregon Department of Energy (ODOE), Lane Community College (LCC) and the Oregon Solar Energy Industries Association (OSEIA) have established fledgling workforce training and development programs. The problem is that the industry is spread across the entire state without sufficient training opportunities for those unable to access training in Eugene or take time off during normal business hours.

**Specific Action Needed** – Recommend state workforce development grants be used for training programs that can build a qualified workforce across the state. Special emphasis should be given to those programs that can enable distance or non-work hour education and involve current higher education and research centers.

## ***2. Improve Net Metering***

Annualized net metering is simpler and less costly to administer than monthly programs. It enables consumers using a seasonal resource like solar to bank summer surplus credit to meet winter time energy use. Annualized net metering is available in two-thirds of the states that currently offer net metering. It is essential for widespread market adoption of utility interactive PV systems.

**Specific Action Needed** – Recommend the Oregon Public Utility Commission (OPUC) adopt net metering rules that require PGE and PacifiCorp to implement annualized net metering and to increase the maximum allowable system size. No legislative change is needed.

## ***3. Oregon Manufacturing***

The worldwide market for PV and ST is now in excess of \$30 billion per year. The California market alone will exceed \$1 billion in 2006. Manufacturing investments needed to meet world demand are estimated at \$10-20 billion in 2006. Oregon should not miss the opportunity to attract and support development of a solar energy industry “cluster” or multiple clusters within the state.

**Specific Actions Needed** – Provide financial incentives or reduced risk for manufacturers of solar equipment that locate in Oregon. Potential mechanisms:

- Establish a PV manufacturing grant
- Increase BETC maximum eligible project size to \$20 million
- Provide bond financing specific to PV manufacturing
- Require new state buildings to include Oregon built PV or ST technologies

#### ***4. Streamline Codes and Interconnection Standards***

Significant barriers and uncertainty remain for the installation company selling and bidding on a project caused by inconsistent interconnection, permitting and inspection standards.

**Specific Action Needed** – Recommend the Oregon Department of Energy host a stakeholders’ workshop to help establish statewide uniform interconnection, permitting and inspection criteria for solar equipment with recommendations submitted to Governor’s office and state legislature.

#### ***5. New Construction***

New construction offers the most logical opportunity for solar energy technologies to be successful without the need for incentives. They provide energy at retail rates, increase the value of the home or building, and offset peak load most effectively. Unfortunately, the current incentive structures are primarily targeted at retrofit applications. Builders have little or no interest taking all the risk of installing solar equipment when the incentives and benefits go the homebuyer. Moreover, if the homebuyer is from out of state, they cannot use the incentive, even though the equipment is placed in service in Oregon.

**Specific Action Needed** – Recommend legislation that enables speculative home builders to use state business energy tax credits for new residential construction that incorporates solar energy technologies which results in “zero net energy” homes.

#### ***6. Continue Existing Levels of Financial Support***

The past five years have seen significant growth in both the scale and maturity of the Oregon solar energy industry. The reason for this has been consumer access to significant financial support for installing PV and ST systems. Incentives have reduced simple paybacks on these technologies to less than 10 years.

**Specific actions** – Include PV and ST set aside in financial support recommendations.

## Appendix D

**Forest Biomass Working Group (FBWG) Report  
Key Federal & State Actions  
Presented to the Renewable Energy Working Group  
March 13, 2007**

**Key Federal Actions in FBWG report:**

1. Call for Congress to fully fund and support development of the US Forest Service Biomass Strategic Plan and the commensurate Bureau of Land Management plan.
2. Request that the US Department of Energy offer solicitations for funding research focusing on the conversion of biomass, such as poplars and grass straw, to cellulosic ethanol.
3. Build a cellulosic ethanol commercial demonstration facility in Oregon within the next two-and-a half years using public/private funds. Public funds could come from USDA Rural Development Agency's 9006 or 9008 programs.
4. Expedite forest stewardship contracting on federal lands through increased appropriations to staff federal lands management agencies.
5. Address the cost of forest biomass, by encouraging funding of the existing federal transportation credit for biomass that was authorized by Congress.
6. Address inequity in the federal production tax credit. Currently the credit for energy generated from biomass is less than for other renewable sources, and the credit is renewed for too short a time period to send the right signal to investors.

**Key State Actions in FBWG report:**

1. Provide funding for a coordinator to facilitate community forums to increase understanding of benefits and consequences of biomass utilization (2 FTE currently in Governor's budget for Oregon Department of Forestry (ODF) to further forest biomass development.)
2. Build on harvesting and research projects that have already been completed and fund new studies to fill in the information gaps (Oregon State University budget).
3. Support action that will help coordinate research and development advances in forest biomass utilization with commercial technology development (Renewable Energy Signature Research Center, SB 580 currently being considered).
4. Continue to develop administrative collaboration under Enrolled Senate Bill 1072 - 2005 session. Points to funding needs for ODF and other state agencies as articulated in the Governor's budget.
5. Consider developing/ expanding Oregon incentives to off-set capital cost of biomass energy facilities. (HB 2210, HB 2211 being considered in 2007 session)

## Appendix E

### **Oregon Renewable Energy Working Group Recommendation RE: Net metering**

The Oregon Renewable Energy Working Group believes that net metering is essential to the advancement of small scale renewable energy systems. It recommends the Oregon Public Utility Commission implement net metering rules for PGE and PacifiCorp that meet the following key criteria:

1. Remains simple for utilities to implement and consumer friendly
2. Establishes Oregon as a leader in net metering policy
3. Requires annualized net metering
4. Prior to setting a size limit the PUC should review the New Jersey net metering standard. Currently NJ has established the leadership position with regard to net metering policy.

Presented to the Renewable Energy Working Group by REWG members:

Bob Chamberlain, Bob Maynard, Jeremiah Baumann, Cylvia Hayes

Date: March 23, 2007  
To: Governor Ted Kulongoski  
From: Mike McArthur, Chair of the Renewable Energy Working Group  
RE: Progress Report from the Renewable Energy Working Group

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You charged the Renewable Energy Working Group (REWG) with developing implementation strategies for *Oregon's Renewable Energy Action Plan*. The Plan, which was finalized in April 2005, includes goals to encourage the growth and development of renewable energy resources and technologies in the state of Oregon. The Plan's ultimate goal is to encourage and accelerate the sustainable production of energy from renewable resources, stimulate economic development, particularly in rural parts of the state, and improve the environmental future of the state. In the Plan, there are specific tasks that are designated for the REWG to consider, as well as tasks for other state agencies and Oregon universities.

The REWG began meeting in February 2006, with a membership comprised of 31 stakeholders and four legislators with interests in energy. The REWG representatives are affiliated with a broad range of stakeholder groups including: utilities, academia, industry, environmental advocacy, and agriculture.<sup>1</sup> Additionally, Oregon's congressional liaisons and staff from related state and federal agencies have attended and participated in the group's meetings.

This is a report of the activities and accomplishments of the REWG over the past year:

- The group met monthly across Oregon, including meetings in Portland, Bend, Eugene, Hood River, Newport, and Salem. The REWG received comments from interested members of the public at their meetings. Additionally, a website was maintained through the Oregon Department of Energy (ODOE) which contained information and recordings from the meetings.
- The group conducted an initial prioritization of the 50+ tasks that were specifically delegated to the REWG. Fifteen of the tasks were general renewable energy items and the rest related to specific renewable energy technologies. They also discussed the information needed in order to inform their deliberations.
- The REWG spent months discussing elements of an RPS for Oregon and working on an outline of a renewable portfolio standard (RPS) proposal for the Governor, which was their top priority task. The REWG was briefed by Dr. Ryan Wiser, a leading expert on RPS development from the Lawrence Berkeley National Laboratory, to begin their discussions. The REWG's work and deliberations on an RPS has formed the basis of your RPS legislation that is currently being brought before the Legislature. REWG members were not in complete agreement on all components of the RPS; however each of those issues is clearly outlined in the attached status report.<sup>2</sup>
- Subcommittees and discussion groups were formed in the areas of biofuels, economic incentives, cost cap aspects of the RPS, and community-scale renewables. These groups met to discuss your legislative proposals and made recommendations to the REWG. These subcommittees and discussion groups include:

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<sup>1</sup> Appendix A contains a list of the current REWG members.

<sup>2</sup> The February 8, 2007 Status Report for the REWG Debate on Oregon's Renewable Portfolio Standard is attached as Appendix B and describes the key concepts within the RPS proposal.

- The biofuels subcommittee worked on your legislative proposal to increase the production and use of biofuels in Oregon. The success that this proposal has had in the Legislature can be traced, in part, to the relative consensus on many issues that this subcommittee's work was able to generate
- The economic incentives subcommittee met to discuss the Business Energy Tax Credit (BETC) and Residential Energy Tax Credit (RETC) programs and how your legislative proposals to improve these programs could be further enhanced. Their efforts helped to build a general consensus among REWG members that led to their endorsement of both of these proposals.
- The "Community Caucus" focused on community-scale renewables and policy elements of the RPS that would encourage the development of a wide diversity of renewable energy sources. This discussion group also debated net metering policy and other policy barriers.
- A small group was also formed to discuss the cost cap provisions of the RPS in detail. This "cost cap" discussion group came to consensus on some basic principles of cost cap design that helped generate final language in the RPS bill.
- Presentations from experts in the fields of renewable energy were delivered to the group. Topics included: RPS design issues and potential policy alternatives, cost comparisons of fossil and renewable energy sources, net metering policy, utility integrated resource planning, and the benefits of small-scale renewables.
- Additionally, the REWG communicated with specialized renewable energy working groups serving Oregon. These groups are working on many of the resource specific tasks designated in the Plan. Key highlights of their interaction with the REWG included:
  - February 2006: the REWG was briefed by Oregon's Wind Working Group, Geothermal Working Group, and Biomass Coordinating Committee, as well as ODOE staff working on solar and biofuels activities.
  - April 2006: the REWG considered and adopted six additional solar policy tasks that were presented by the Oregon Solar Coalition.<sup>3</sup>
  - January 2007: the Forest Biomass Working Group prepared a report and presentation to the REWG that identified obstacles and opportunities in biomass development for Oregon.
  - March 2007: the REWG adopted 11 key follow up action items from the Forest Biomass Working Group report in order to help support biomass utilization.<sup>4</sup>
- The REWG discussed net metering and developed suggestions for Oregon's net metering process in a letter that was transmitted to the Oregon Public Utility Commission.<sup>5</sup> While not unanimously supported, and thus not representing a consensus of the REWG, a majority of REWG members endorsed the letter.

Over the past year, the REWG worked on seven of the 15 cross-cutting tasks delegated to them in the Plan. A tremendous amount of time and energy was devoted to the largest task, the development of an RPS. In the upcoming months, the REWG will reassess and prioritize future tasks to accomplish and oversee from the Plan. The REWG will continue to coordinate with the other working groups and encourage collaboration and a partnership of efforts related to renewable energy.

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<sup>3</sup> The Solar Policy Tasks are listed in the document attached as Appendix C.

<sup>4</sup> Appendix D contains the recommended forest biomass action items adopted by the REWG at the March 13, 2007 meeting.

<sup>5</sup> The letter to the PUC on net metering is attached as Appendix E.

## Appendix A Membership of the Renewable Energy Working Group (REWG)

**Legislators:** Sen. Kate Brown, Rep. Jackie Dingfelder, Sen. Ted Ferrioli, and Rep. Patti Smith

**Chair of the REWG:** Mike McArthur, Executive Director of the Association of Oregon Counties

Name	Affiliation	Title
Kevin Banister	Finavera Renewables	Director, Business Development
Jeremiah Baumann	Oregon State Public Interest Research Group	Environmental Advocate
Ted Bernhard	Stoel Rives LLP	Attorney, Technology Ventures Group
Jeff Bissonnette	Citizens' Utility Board of Oregon	Director, Fair & Clean Energy Coalition
Julie Brandis	Associated Oregon Industries	Legislative Representative; Energy
Barbara Byrd	AFL-CIO	Secretary-Treasurer
Kyle Davis	PacifiCorp	Environmental Policy Manager
Angus Duncan	Bonneville Environmental Foundation	Executive Director
Michael Early	Industrial Customers of Northwest Utilities	Executive Director
Bill Fashing	Oregon Economic Development Association	Board Member, Past President
Katie Fast	Oregon Farm Bureau	Associate Director of Governmental Affairs
David Shaw	Oregon Rural Electric Cooperative Association	Manager of Regulatory Affairs
Troy Gagliano	Renewable Northwest Project	Senior Policy Associate
Don Godard	Oregon People's Utility District Association	Executive Director
Michael Grainey	Oregon Department of Energy	Director
David Hackleman	Oregon State University	Linus Pauling Chair, Chemical Engineering
Cylvia Hayes	3E Strategies (Business Alliance for Sustainable Energy)	Executive Director
Jim Lobdell	Portland General Electric	Vice President, Power Operations and Resource Strategy
John Lund	Oregon Institute of Technology	Director, Geo-Heat Center
Jim Manion	Warm Springs Power Enterprises (Confed. Tribes of Warm Springs)	General Manager
Bob Maynard	Energy Outfitters	President/Founder
Carlos Reichenshammer	Reichenshammer Building & Design	President, Oregon Homebuilders Association
Tucker Ruberti	Idatech	Market Development Manager
Chris Taylor	Horizon Wind, Northwest Office	Director of Development
Jim Walls	Lake County Resources Initiative	Executive Director
Dick Wanderscheid	The City of Ashland Electric Department	Electric & Telecommunications Director
Peter West	Energy Trust of Oregon	Director of Renewable Energy Programs
Jonathan Williams	Intel	Government Affairs Manager
Scott Winkels	League of Oregon Cities	Staff Associate
Paul Woodin	Community Renewable Energy Association	President

**Governor's Representative to the REWG:** David Van't Hof, Governor's Sustainability Advisor

(3/12/2007)

**Status Report: REWG Debate on Oregon’s Renewable Portfolio Standard**

**Targets**

Summary of Key Concepts	Areas of Agreement	Areas of Disagreement
General Structure	General consensus that use of RECs for RPS compliance is acceptable.	Some are fundamentally and philosophically opposed to the RPS or similar style mandates. Thus such disagreement would extend to every box below and the policy as a whole.
The proposed renewable portfolio standard (RPS) for Oregon consists of three separate standards, tied together by a common set of implementation and compliance parameters that are based on the use of Renewable Energy Certificates (RECs) to serve as the compliance mechanism for the RPS. All utilities in Oregon would be subject to a primary or secondary standard, and Electricity Service Suppliers would have a related standard.		
Primary Standard for Utilities	Most seem to agree that using percentage of retail sales as the metric of RPS applicability is acceptable.	Where threshold for RPS applicability should fall: Lower limit: ½ percent Upper: limit 5 percent.  Number of “hard” targets: Lower limit: none Upper limit: every year  Some would like standard to be load growth only.
Those utilities that are responsible for one percent or greater of total retail electric sales in Oregon would be required to ensure that by 2025 and beyond at least 25 percent of their retail sales come from renewable sources. Similarly, interim targets are set for 2011, 2015, and 2020 at 5, 15, and 20 percent, respectively. The target level remains in effect each year until the next target becomes effective, creating a minimum floor for compliance.		
Secondary Standard for Utilities	Most seem amenable to the “lesser burden of ” concept to avoid unwanted interaction effects between the Primary and Secondary standards (i.e., the burden of the Secondary surpassing that of the Primary in later years)	Some question need for Secondary standard.  60 percent of retail sales growth considered too high by some.
Utilities responsible for less than one percent of total retail electric sales in Oregon would be required to meet the lesser burden of having either 60 percent of any growth in retail sales or 25 percent of their total retail sales come from renewable sources by 2025 and thereafter. To begin with in 2015 these utilities would be required to meet the lesser burden of having either 20 percent of growth in retail sales or 15 percent of their total retail sales come from renewable sources by 2015 and each year after until 2020. Similarly, by 2020 these utilities would be required to meet the lesser burden of having either 40 percent of growth in retail sales or 20 percent of their total retail sales come from renewable sources by 2020 and each year after until 2025.		
Standard for Electricity Service Suppliers (ESSs)	ESSs should be subject to a standard that creates a “level playing field” between utilities and ESSs in Oregon.	Some not sure of feasibility of implementing standard in this manner.
ESSs are required to ensure that in each year the RPS is in effect the amount of their retail sales that come from renewable sources is equal to an amount that is calculated as if each of the ESS’s customers were instead being served by their applicable utility based on the service territory in which those customers reside. Thus, this summation of retail sales obligations may include a mix of amounts from both the primary and secondary standards.		
Federal Base System (FBS) Firm Power Exemption	General consensus that preference rights to firm FBS BPA power should not be lost due to RPS obligations.	Belief that the same guarantee should extend to non-firm BPA power. Concern about slice customers.
If RPS requirements would unavoidably displace firm FBS power preference rights for a consumer-owned utility in a given year then the obligation for that utility is reduced proportionally by an amount equal to that unavoidable displacement of power.		

<b>RPS Obligations in Excess of Load Growth</b>	Most seem to agree with the principle behind this provision.	Belief that only the second clause of this provision (regarding displacement of non-fossil fueled resources) should apply.
If the primary standard results in a utility having no other choice but to acquire power resources in excess of their load growth in a compliance year, and if the RPS obligation would result in the displacement of a power resource other than a fossil-fueled resource by the utility, the requirement for that compliance year is reduced by an amount up to such displacement.		
<b>Mid-Columbia Hydropower Obligation Deferment</b>	Most seemed to accept logic that this situation is substantially similar to BPA power and deserves consideration.	Belief that the same deferment opportunity should extend to IOUs.
For those consumer-owned utilities that have low-price hydro contracts with the Mid-Columbia non-federally owned dams the RPS obligation for a given year is reduced by an amount equal to the amount of power obtained under said contracts until those contracts are no longer in effect, or until those contracts can't be renewed at a substantially similar low-cost power rate.		
<b>Cost Cap Off-Ramp Provision</b>	General consensus that cost cap provision is an essential element to the RPS. Some agreement on very basic elements of cost cap structure.	Disagreement on retail revenues vs. power costs, need for additional cost effectiveness test, cost cap percentage, and a long list of other issues.
Utilities need only comply with the renewable portfolio standard in a given year up to the point where they expend a percentage (proposed as 4 percent) of their RPS-applicable portion of annual revenue requirements on the costs of RPS compliance.		
<b>Movement From Secondary Standard To Primary Standard</b>	Most seemed to agree to this provision.	
When a utility that was responsible for less than one percent of Oregon's total retail electric sales increases its share of those sales to one percent or more, then that utility becomes subject to the primary standard. However, its burden under the RPS is calculated under a timeline adjusted such that it has the same ramp-up of obligations as if it had been in the primary standard since the start date of the RPS program.		

## Resources

<b>Date of Eligibility</b>		Some would prefer no date, i.e., all qualifying resources eligible. For those that agree a date makes sense the range is: Lower limit: 1981 Upper limit: 1999
Generating facilities using qualifying renewable resources must have been placed into operation on or after January 1, 1995.		
<b>Facility Location</b>	The geographic eligibility for the Oregon RPS need not extend beyond WECC.	Many would prefer it be limited to Pacific NW, others would like Oregon-only to the extent feasible.
Facilities using qualifying renewable resources must physically reside in the geographic boundaries identified by the North American Electric Reliability Council (NERC) Western Electricity Coordinating Council (WECC) region.		
<b>Standard RPS Resources</b>	General consent seemed to exist for all of these resources at the Eugene REWG meeting.	
Electricity generated from wind, solar photovoltaic, solar thermal, wave, tidal, ocean thermal, and geothermal would all be RPS eligible.		

Incremental or Proportionate Resources	After modifications, most seem OK with these resources.	Some would like efficiency and conservation measures to count as resources in RPS.
Both the renewable proportion of a multi-fuel generation process and the incremental improvement to a qualifying renewable energy generating unit (non-hydro) made through capital improvements after the qualifying date would be eligible.		
Hydrogen and Fuel Cells	Most seem OK with this resource given the qualifications.	Some would like fuel cell use to not be dependent on renewable sources.
Electricity generated from the use of hydrogen reformed from or electrolyzed entirely from qualifying renewable resources would be eligible. The use of fuel cells, in and of themselves, would not necessarily qualify unless the hydrogen fuel in use qualified.		
Biomass and Biogas Resources	Most seem to agree with those resources described by the first sentence. General consensus with biogas range of inclusions.	Many disagree on including spent pulping liquor and/or excluding MSW combustion. Concern about the lack of sustainability criteria. Some question feasibility of excluding treated wood
Includes biomass and byproducts from organic human or animal waste; solid organic fuels from wood, forests, and field residues; and dedicated energy crops. Includes spent pulping liquor. Includes biogas from organic sources, wastewater, anaerobic digesters, and municipal solid waste (e.g. landfills). Does not include wood treated with chemical preservatives or municipal solid waste combustion.		
Hydropower	General agreement that low-impact hydro should qualify.	Disagreement about nearly all aspects of what type of limits on hydropower to include.
Any hydroelectric facility not located in a federally-protected area in effect upon the enactment of SB 1149, i.e., not on a river or stream area listed by the Northwest Power and Conservation Council as protected or considered a Wild and Scenic River by Congress.		
Incremental Improvements to Hydropower Facilities	Most seem to agree that hydro efficiency projects should be included to some degree.	Disagreement as to whether BPA dam projects should be included, as well as on amount of projects that should be eligible. Problems with proportion calculation noted by some.
The increment of improvement resulting from an efficiency upgrade to an existing hydropower facility, completed after the qualifying date, would qualify but there would be an upper limit on the use of BPA efficiency projects based on the proportion of FBS power that Oregon COU's receive relative to the total amount (i.e, from WA/ID/MT).		
Determination of Additional Qualifying Resources		Some feel that additional resource determination should be left to legislature.
An ODOE rulemaking procedure will be established to add new resources as necessary to the eligibility list for the RPS. Under no circumstances, however, will electricity derived from fossil fuel resources, nuclear, or the combustion of municipal solid waste be considered an eligible resource under the RPS.		
BPA Renewable Energy Product	Most agree that allowance should be made for BPA EPP-type product.	
Irrespective of any delivery requirement, Oregon RPS-qualifying RECs associated with BPA Environmentally Preferred Power (EPP) or a substantially similar product from BPA ("Tier II Renewable Product") would be eligible for the RPS.		

## Renewable Energy Certificates

Use of Renewable Energy Certificates (RECs)	No disagreement on using WREGIS system.	
REC verification and tracking will come from the Western Renewable Energy Generation Information System (WREGIS).		

Timing of Bundled REC Creation	Most seem amenable to accepting this definition, along with the implications for allowing shaping and firming resources.	
A bundled REC is considered to be created at the point when qualifying renewable power hits the first point of interconnection with the BPA control area, the Northwest Power Pool (NWPP) control area, or any Oregon RPS-obligated utility's transmission system. This has important implications for shaping and firming resources, as it allows unlimited substitution of the power component of a bundled REC as it makes its "journey" from that first point of interconnection to an Oregon RPS-obligated utility.		
Usage of Unbundled RECs for Compliance	Most seem OK with the inclusion of some level of unbundled RECs	Geography: WECC vs. Pacific NW (noted above)
No more than 20 percent of compliance within a given compliance year for the Primary standard can be met with unbundled RECs, but these RECs can come from anywhere within the WECC. No upper limit exists for the Secondary or ESS standard. Exemptions for certain RECs from smaller projects can raise the upper limit.		Upper limit: Some want unlimited, others closer to 5 to 10 percent limit
Usage of Bundled RECs for Compliance	Most seem comfortable with WECC region for bundled RECs as an outer boundary.	Some would prefer to get rid of delivery language and simply base eligibility on physically located within WECC.
Bundled RECs will comprise the majority of compliance with the RPS. Eligible bundled RECs derive from facilities located with the WECC and that deliver power to Oregon RPS-obligated utilities through a path involving the BPA control area, the Northwest Power Pool (NWPP) control area, or any Oregon RPS-obligated utility's transmission system, or a combination of the above systems.		
RECs Funded from the Public Purpose Charge	General consensus (once this got fixed) seems to exist on this.	
In cases where RECs derive from projects funded by the public purpose charge and are then retired on behalf of ratepayers those RECs will be credited to the utility serving those ratepayers.		
RECs from Small-Scale Renewable Energy Projects	Most seem OK with this.	Some believe that Oregon-only part of language might cause legal issues.
The ceiling on unbundled RECs is raised by one MWh for each bundled REC purchased from a PURPA "qualifying facility" located in Oregon. Unbundled RECs from WREGIS-qualifying off-grid and customer-sited resources located in Oregon are RPS eligible and also exempt from the ceiling on unbundled RECs.		
RECs from Voluntary Green Energy Utility Programs	Most seem OK with Gov's Office idea of "returning" RECs from state facilities back to utilities for RPS use.	Disagreement as to whether such policies may be applied to COUs.
RECs obtained by utilities and used to satisfy voluntary retail green pricing tariff programs ("green power programs") are not eligible for RPS compliance. RECs transferred to customers by such a program may, at the customer's sole discretion or through voluntary contract, be transferred back to the utility for RPS use.		
REC Integrity	Most seem OK with these concepts.	
RECs used for the Oregon RPS can't be used for other states' RPS programs. No disaggregation (removing one or more individual attributes) of RECs is allowed. In future legislation mechanisms will be devised to allow RECs used for compliance with the Oregon RPS to comply with any potential carbon cap legislation that emerges.		
Multi-state Allocation of RECs for RPS Compliance	Unknown.	
For a multi-state IOU decisions on the share of bundled RECs allocated to Oregon will reflect the above-market costs paid by Oregon ratepayers and a fair allocation of RECs for market (or cheaper) cost purchases as determined by OPUC proceedings.		

## Compliance

Route of Compliance		
Utilities and ESSs request that RECs be retired in the WREGIS system to achieve the desired level of annual compliance.	Most seem to be fine with use of WREGIS.	
Flexibility in Reaching Annual Compliance		
RECs may be retired up to 90 days past the year in which they are intended to satisfy compliance, and may be banked for an unlimited amount of time. However, banked RECs must be retired on a first in, first out (FIFO) basis so that the oldest RECs being banked are used prior to any newer RECs being used.	Most seem fine with 90 day “true up” period.	Some believe that a “shelf life” (i.e., a time limit on the use of RECs) should be put on banked RECs.
Minimum Level of Annual Compliance for Primary Standard		
Each utility must retire enough RECs every year to satisfy the target in effect for that year. At a minimum, enough RECs must be retired to meet the last interim or final target in effect or the interim or final target that goes into effect that year. This “step function” creates a minimum floor of compliance for utilities.		
Minimum Level of Annual Compliance for Secondary Standard		
Each utility must retire enough RECs to meet their obligation as determined by the percentage target in effect that year and the increase in retail sales (if any) for that utility during that year.		
Minimum Level of Annual Compliance for ESS Standard		
Each ESS must retire enough RECs to meet their annual burden as determined through the aggregation of their customer’s relevant utility obligations as described in the target section.		
Filing of Compliance Plans		
Each utility must submit a compliance plan every two years to ODOE (for COUs) or OPUC (for IOUs and ESSs) that specifies exact “soft” targets above the minimum compliance floor for which the utility will strive to achieve. For IOUs this reporting process will be aligned with IRP protocols to the extent possible.		Disagreement as to whether COUs should have to submit compliance plans.
Compliance Letter		
All utilities and ESSs will submit a letter to ODOE (for COUs) or OPUC (for IOUs and ESSs) noting their level of compliance for a given year and any reasons for not meeting either the minimum level of compliance or a “soft” target for a given year.	Most agree that a notification on whether a utility has complied or not is reasonable.	Disagreement as to whether ODOE should require compliance letters from COUs.
Compliance Determination		
After submission of the compliance letter ODOE (for COUs) or OPUC (for IOUs and ESSs) will make a determination as to whether the utility or ESS is in compliance for a given year.		Disagreement as to whether ODOE should have the right to make such determinations.

## Compliance Shortfalls

<u>Option 1: Alternative Compliance Payments</u>		
Alternative Compliance Payment Mechanism		Inclusion of the alternative compliance payment mechanism is highly controversial.
If alternative compliance payments are included as a mechanism then any shortfalls in compliance using RECs could be addressed by paying a dollar per MWh payment total to a designated entity (or into a special fund) to be used for acquiring eligible resources in the future.		
Designation of Alternative Compliance Payment Amount		For those that support the alternative compliance payment mechanism, there is a large degree of debate as to where the level should be set.
The alternative compliance payment amount would be an amount higher than, and indexed to, the incremental costs associated with eligible resources, as determined by the PUC or the applicable governing body for consumer-owned utilities.		
<u>Option 2: Penalties</u>		
Penalty Determination for Primary Standard	Most seem OK with idea of applying 3-year average before making penalty determination.	Concern with delay involved if the 3-year average test is used.
Penalties are only applied if the compliance determination finds that the minimum floor of compliance is not achieved in a given year between targets or, for each interim target year and beginning with the final target year, after an additional three-year averaging test is applied and the results of that average also indicate a level of compliance below the target for that year.		Disagreement about penalties for COUs.  Some support alternative compliance payment scheme in lieu of penalties.
Penalty Determination for Secondary and ESS Standard		Disagreement about penalties for COUs.
If a utility or ESS is found not to have retired sufficient RECs to be in compliance in a given year then penalties will be applied		Some support alternative compliance payment scheme in lieu of penalties.
Penalty Amount and Appeal Process	General consensus that penalties, if used, should be non-recoverable.	Disagreement as to amount of the penalty and the applicability to COUs of such penalties.
A penalty of \$45 per MWh of shortfall will be assessed on any utility or ESS deemed out of compliance after the appropriate test. This penalty will be non-recoverable in rates for IOUs. A penalty hearing process will be created through rulemaking so that in exceptional hardship cases penalties may not be applied.		
Penalty Recipient	Most seem to agree that it is fine for IOU penalties to go to PPC entity.	Disagreement on dispatch of COU penalties to third party entity.
Penalties from IOUs will be paid to the NGO sub-contracted to the OPUC to manage public purpose charge funds and used for renewable energy projects. Penalties from COUs will be paid to a similar entity (to be determined through rulemaking by ODOE) for renewable energy projects in consumer-owned utility territory or territories.		

## Task Force

Periodic Task Force	Most seem to agree that some sort of feedback mechanism is appropriate.	Some disagreement about timing and scope of authority.
A task force will be convened by the Governor after each of the Primary interim target years to evaluate the RPS and report back to the Legislature if there are items that need to be addressed.		

## Public Purpose Charge

Renewable Energy Component of the Public Purpose Charge	Community Caucus agreed to this provision (among others) in lieu of a “carve out” target for small-scale renewable energy.	Some do not feel this should be part of RPS. Some think 20 MW is too big.
Focus the renewable energy portion of the Public Purpose Charge on funding a mix of projects of 20 MW or less and exclude funding of projects larger than 20 MW. Require as part of this statute that the OPUC will ensure that implementation of public purpose charge programs reflects this change in focus.		
Extension of the Public Purpose Charge (PPC)	Part of Community Caucus agreement.	Disagreement as to whether PPC should be extended to any degree.
Extend the public purpose charge through 2025 so that the PPC will be consistent with and serve as a complement to the RPS policy to promote a diversity of renewable energy sources.		

## Related Energy Policy

Cost Recovery for Investor-Owned Utilities	General consensus that this seems reasonable.	Concern about cost recovery aspects of early-stage renewable development activity.
Compliance with the RPS is not considered an above-market cost as defined in ORS 757.612(1). In addition, all prudently incurred costs associated with RPS compliance are recoverable under the RPS, including those associated with transmission and delivery of renewable energy to customers in Oregon.		
Mandatory Green Power Program for all Utilities		Disagreement as to necessity and desirability of such a mandate.
All utilities will be required to offer a voluntary green power purchasing program to their customers. Program details are largely left to the discretion of the utility		
State PURPA Reinstatement	Part of Community Caucus agreement.	Disagreement as to whether this should be part of package.
Modify ORS 757.612 (4) to require PGE and Pacific Power to meet state PURPA Statute ORS 758.505 to 758.555.		
Non-binding Goal for Community Energy	Community Caucus agreed to this provision (among others) in lieu of a “carve out” target for small-scale renewable energy.	Disagreement as to whether goal is necessary or appropriate. Arguments about semantics in regard to the word “goal”.  Some support multiplier for small-scale projects.
A non-binding goal will be included in the RPS that at least eight percent of Oregon’s retail sales should come from a mix of small-scale renewable energy projects by 2025. Direction to state agencies to try and help achieve this goal through appropriate policies and programs would also be included.		
Changes to ORS for People’s Utility District RPS Compliance	No objections noted at Portland meeting when the group was queried.	
1) Authority to operate on REC market. 2) Revise ORS to exempt renewables from cost effective test. 3) PUDs eligible for renewable energy development zones. 4) Change various facets of public voting for PUDs. 5) Change various facets of financing for PUDs. 6) Change taxations status for PUD partially owned projects. 7) Change public contracting requirements for renewables. 8) Allow PUDs to participate in Joint Operating Agencies. 9) Allow PUDs to form LLC’s for renewables development. 10) Revise ORS regarding PUD’s and judicial validation.		

# Solar Policy Tasks

Recommendations for the Renewable Energy Working Group  
by the Oregon Solar Coalition

This document was developed by in consultation with the members of the Oregon Solar Coalition to provide the Renewable Energy Working Group (REWG) with a short list of key steps that should be taken to advance solar photovoltaic (PV) and solar thermal (ST) businesses in Oregon. The REWG should consider to take action on each of the following items.

### ***1. Workforce Development***

The combined efforts of the Energy Trust of Oregon (ETO) and the Oregon Department of Energy (ODOE), Lane Community College (LCC) and the Oregon Solar Energy Industries Association (OSEIA) have established fledgling workforce training and development programs. The problem is that the industry is spread across the entire state without sufficient training opportunities for those unable to access training in Eugene or take time off during normal business hours.

**Specific Action Needed** – Recommend state workforce development grants be used for training programs that can build a qualified workforce across the state. Special emphasis should be given to those programs that can enable distance or non-work hour education and involve current higher education and research centers.

### ***2. Improve Net Metering***

Annualized net metering is simpler and less costly to administer than monthly programs. It enables consumers using a seasonal resource like solar to bank summer surplus credit to meet winter time energy use. Annualized net metering is available in two-thirds of the states that currently offer net metering. It is essential for widespread market adoption of utility interactive PV systems.

**Specific Action Needed** – Recommend the Oregon Public Utility Commission (OPUC) adopt net metering rules that require PGE and PacifiCorp to implement annualized net metering and to increase the maximum allowable system size. No legislative change is needed.

### ***3. Oregon Manufacturing***

The worldwide market for PV and ST is now in excess of \$30 billion per year. The California market alone will exceed \$1 billion in 2006. Manufacturing investments needed to meet world demand are estimated at \$10-20 billion in 2006. Oregon should not miss the opportunity to attract and support development of a solar energy industry “cluster” or multiple clusters within the state.

**Specific Actions Needed** – Provide financial incentives or reduced risk for manufacturers of solar equipment that locate in Oregon. Potential mechanisms:

- Establish a PV manufacturing grant
- Increase BETC maximum eligible project size to \$20 million
- Provide bond financing specific to PV manufacturing
- Require new state buildings to include Oregon built PV or ST technologies

#### ***4. Streamline Codes and Interconnection Standards***

Significant barriers and uncertainty remain for the installation company selling and bidding on a project caused by inconsistent interconnection, permitting and inspection standards.

**Specific Action Needed** – Recommend the Oregon Department of Energy host a stakeholders’ workshop to help establish statewide uniform interconnection, permitting and inspection criteria for solar equipment with recommendations submitted to Governor’s office and state legislature.

#### ***5. New Construction***

New construction offers the most logical opportunity for solar energy technologies to be successful without the need for incentives. They provide energy at retail rates, increase the value of the home or building, and offset peak load most effectively. Unfortunately, the current incentive structures are primarily targeted at retrofit applications. Builders have little or no interest taking all the risk of installing solar equipment when the incentives and benefits go the homebuyer. Moreover, if the homebuyer is from out of state, they cannot use the incentive, even though the equipment is placed in service in Oregon.

**Specific Action Needed** – Recommend legislation that enables speculative home builders to use state business energy tax credits for new residential construction that incorporates solar energy technologies which results in “zero net energy” homes.

#### ***6. Continue Existing Levels of Financial Support***

The past five years have seen significant growth in both the scale and maturity of the Oregon solar energy industry. The reason for this has been consumer access to significant financial support for installing PV and ST systems. Incentives have reduced simple paybacks on these technologies to less than 10 years.

**Specific actions** – Include PV and ST set aside in financial support recommendations.

## Appendix D

**Forest Biomass Working Group (FBWG) Report  
Key Federal & State Actions  
Presented to the Renewable Energy Working Group  
March 13, 2007**

**Key Federal Actions in FBWG report:**

1. Call for Congress to fully fund and support development of the US Forest Service Biomass Strategic Plan and the commensurate Bureau of Land Management plan.
2. Request that the US Department of Energy offer solicitations for funding research focusing on the conversion of biomass, such as poplars and grass straw, to cellulosic ethanol.
3. Build a cellulosic ethanol commercial demonstration facility in Oregon within the next two-and-a half years using public/private funds. Public funds could come from USDA Rural Development Agency's 9006 or 9008 programs.
4. Expedite forest stewardship contracting on federal lands through increased appropriations to staff federal lands management agencies.
5. Address the cost of forest biomass, by encouraging funding of the existing federal transportation credit for biomass that was authorized by Congress.
6. Address inequity in the federal production tax credit. Currently the credit for energy generated from biomass is less than for other renewable sources, and the credit is renewed for too short a time period to send the right signal to investors.

**Key State Actions in FBWG report:**

1. Provide funding for a coordinator to facilitate community forums to increase understanding of benefits and consequences of biomass utilization (2 FTE currently in Governor's budget for Oregon Department of Forestry (ODF) to further forest biomass development.)
2. Build on harvesting and research projects that have already been completed and fund new studies to fill in the information gaps (Oregon State University budget).
3. Support action that will help coordinate research and development advances in forest biomass utilization with commercial technology development (Renewable Energy Signature Research Center, SB 580 currently being considered).
4. Continue to develop administrative collaboration under Enrolled Senate Bill 1072 - 2005 session. Points to funding needs for ODF and other state agencies as articulated in the Governor's budget.
5. Consider developing/ expanding Oregon incentives to off-set capital cost of biomass energy facilities. (HB 2210, HB 2211 being considered in 2007 session)

## Appendix E

### **Oregon Renewable Energy Working Group Recommendation RE: Net metering**

The Oregon Renewable Energy Working Group believes that net metering is essential to the advancement of small scale renewable energy systems. It recommends the Oregon Public Utility Commission implement net metering rules for PGE and PacifiCorp that meet the following key criteria:

1. Remains simple for utilities to implement and consumer friendly
2. Establishes Oregon as a leader in net metering policy
3. Requires annualized net metering
4. Prior to setting a size limit the PUC should review the New Jersey net metering standard. Currently NJ has established the leadership position with regard to net metering policy.

Presented to the Renewable Energy Working Group by REWG members:

Bob Chamberlain, Bob Maynard, Jeremiah Baumann, Cylvia Hayes

# **REWG's Community Caucus Report**

Presented to Oregon's Renewable Energy Working Group, July 11<sup>th</sup>, 2006

The REWG should make recommendations to the Governor that pursue the benefits of both large-scale generation systems (like central station wind or geothermal) and community renewables (like solar, biomass, small hydro, geothermal and community wind). Neither approach by itself will achieve the optimal outcome of a sustainable energy system with broad statewide support.

## ***Importance of Community Renewables***

1. Community Renewables diversify Oregon's energy portfolio, providing increased system stability and reliability, and improved energy efficiency and environmental benefits.
2. Community Renewables create enhanced economic opportunities throughout Oregon and keep more energy dollars within the state.
3. Community Renewables keep Oregon competitive in emerging renewable energy industries.

## ***Proposed Necessary Actions by the Legislature***

1. Focus the renewable energy portion of the Public Purpose Charge (PPC) on funding a mix of community projects of 20 MW or less. Require the OPUC to ensure that implementation of PPC programs reflects this change in focus.
2. Endorse the OPUC's Legislative Concept to extend the PPC funding through the year 2022 or extend the PPC funding through 2025 to be consistent with the RPS policy.
3. Endorse the OPUC's Legislative Concept to authorize the OPUC to increase the PPC funding beyond the current 3% to provide more funding for renewables (currently at 0.51 percent) without taking money away from valuable energy efficiency projects. Furthermore, the 3% should be set as a floor below which the PPC should not be reduced.
4. Propose an Oregon version of the PURPA-type requirement that utilities have to purchase the power from projects of qualifying renewable projects of 10 MW or less using standard contracts, and over 10 to 20 MW using non-standard contracts. Such requirements would be regulated by the OPUC.
5. Require the OPUC to modify policies and procedures as appropriate to meet a goal of generating at least 8% of Oregon's electricity from a mix of community renewables by 2025.
6. Establish statewide uniform interconnection and enhanced net metering standards.

## ***Process***

The Community Caucus met extensively to discuss major barriers to significant development of community-scale renewable energy, as well as various policy changes to address those barriers. The Caucus considered several major policy concepts that would be new policy directions for Oregon. We discussed an 8 percent carve-out setting aside a portion of a Renewable Portfolio Standard for community-scale renewable energy, as other states have used, with a separate cost cap from the overall RPS cost cap. We also considered an advanced renewable tariff (ART), as European countries have used. The Community Caucus believes that neither policy is ideal for Oregon. Instead, we are proposing an Enhanced Public Purpose Charge consisting of incremental changes to the existing Public Purposes Charge (actions 1-3) combined with 3 other necessary actions (actions 4-6).