Portland General Electric
121 SW Salmon Street · Portland, Ore. 97204

October 15, 2019

Via Electronic Filing
puc.filingcenter@state.or.us

Public Utility Commission of Oregon
Attn: Filing Center
201 High Street, Ste. 100
P.O. Box 1088
Salem, OR 97308-1088

Re: **UM 1930 – Joint Comments on Staff's October 4, 2019 Report to the Commission**

Portland General Electric Company (PGE) submits for filing with the Public Utility Commission of Oregon the Joint Comments of PacifiCorp d/b/a Pacific Power addressing Staff's policy recommendations in the Staff Report as related to the calculation of bill credits, incorporating an escalator to the residential retail rate, expanding the interim capacity tier, and the declared need to guarantee bill savings to ensure program participation. Workpapers associated with this filing have been submitted to puc.workpapers@state.or.us.

Informal questions concerning this filing may be directed to Stefan Cristea at (503) 464-8033. Please direct all formal correspondence, questions, or requests to the following e-mail address: pge.opuc.filings@pgn.com.

Sincerely,

Jay Tinker

Jay Tinker,
Director, Regulatory Policy & Affairs

Enclosures

UM 1930
PGE and PacifiCorp Joint Comments to October 4, 2019 Staff Report

I. Introduction

In accordance with the schedule provided in Table 1 of the October 4, 2019 Staff Report (Staff Report), PacifiCorp d/b/a Pacific Power and Portland General Electric Company (PGE) submit these comments to the Public Utility Commission of Oregon (Commission) addressing certain policy recommendations proposed in the Staff Report. PacifiCorp and PGE appreciate the considered analysis presented in the Staff Report and Commission Staff's (Staff) efforts to compile such a comprehensive report. In addition to these comments, PacifiCorp, PGE, and Idaho Power Company have submitted joint comments with respect to the interconnection recommendation.

In 2015, the legislature passed House Bill 2941,[1] directing the Commission to report to the legislature with recommendations for a community solar program (CSP). Consistent with the legislation, the Commission solicited feedback from stakeholders and ultimately submitted its report to the Legislature on October 26, 2015, provided here as Attachment A to these comments.[2] Interestingly, for purposes of reviewing the Staff Report, the Commission's 2015 report contained the following criteria to identify preferred attributes of community solar:

- Programs should stress providing fair access to Oregon households and small businesses that do not have the ability to install solar on their own property.
- Programs should shift no costs onto non-participating ratepayers.
- Programs should be designed for easy and efficient administration.
- Programs should allow for adaptations as we gain experience.

Subsequently, the legislature incorporated the Commission's feedback into the CSP design created in Senate Bill (SB) 1547, which passed in the 2016 legislative session. Since its passage, the Commission and stakeholders have worked diligently and in good faith to implement CSP, recognizing that the CSP program is a difficult program to implement from both a legal[3] and an administrative perspective. The scope of the program—which goes far beyond traditional, on-site net metering and can venture into what is essentially large-scale solar that requires a transmission wheel—raises a host of interrelated potential legal issues, including the concern that an aggrieved party may raise a serious federal preemption concern.[4] The web of

[1] See at: https://olis.leg.state.or.us/liz/2015R1/Downloads/MeasureDocument/HB2941/Enrolled.

[2] The report is also available at: https://edocs.puc.state.or.us/efdocs/HAH/um1746hah131652.pdf.

[3] Indeed, in the initial phase of implementation, a special sub-group of lawyers was convened specifically to address the legal challenges of implementing CSP, including jurisdictional issues and securities law issues. The legal analysis attached here as Attachment B was provided by PacifiCorp and PGE to staff on an informal basis as part of the legal sub-group work.

[4] At the core of the federal preemption concern is whether the state-created "virtual" netting associated with the community solar program would ultimately be found by the Federal Energy Regulatory Commission (FERC) to be a wholesale sale rather than a type of net metering. In the early phases of the program's development, the most commonly discussed ramification of a wholesale sale determination focused on the fact that the state commission

agreements and parties involved in the various pieces of this total transaction adds a further layer of complexity. The CSP legislation, by its nature, has created a series of challenges stakeholders have worked hard to overcome.

Despite these challenges, and the fact that some issues still require resolution,[5] the Commission has been able to chart a reasonable path forward for CSP implementation. In Order 18-177, the Commission, among other things, effectively established the initial 25 percent capacity tier as a CSP pilot. This structure allows the Commission and stakeholders to move forward with implementation of CSP while monitoring the impacts of program design. It also seemed to fit with the design criteria identified in the Commission's 2015 report that program design should "allow for adaptations as we gain experience."

PacifiCorp and PGE are therefore surprised to now see Staff proposing wholesale changes to the pilot or adaptation nature of the CSP framework initially adopted by the Commission; we take exception to many recommendations contained in the Staff Report, including changes to the calculation of bill credits, incorporating an escalator to the residential retail rate, tripling the interim capacity tier, and the declared need to guarantee bill savings to ensure program participation. These changes represent a significant deviation from the 2015 design criteria the Commission recommended to the legislature that the program be easily and efficiently administered and that there be no cost shifting to nonparticipating customers.

Also addressed in these comments is one of Staff's newest recommendations that the Commission waive Oregon Administrative Rules (OAR) §860-088-0170(2) and adopt new bill credit mechanics. PacifiCorp and PGE oppose these late-in-the-game proposals that radically shift the nature of the CSP, because, among other considerations, they are contrary to statute and prior Commission decisions, constitute substantial cost shifting, and eliminate the pilot nature of

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would not then have the authority to establish an administratively set price for these transactions. As noted above, PacifiCorp and PGE flagged this basic concern early on, although it was unclear if it would ultimately be an issue because many of the implementation details had not been developed yet. Now, however, those details are becoming more defined, and the core jurisdictional concern also threads through other elements of the program. For example, if the transactions are in fact wholesale sales, then the interconnection service provided to community solar generators is also FERC-jurisdictional. In that case, a party may take issue with community solar interconnection requests being studied like net metering generators, rather than serially processed FERC-jurisdictional generators—a solution that was proposed by the utilities to address staff concerns with queue processing timeframes, but that depends on the community solar transactions being a type of net metering as determined by the state, not wholesale sales.

[5] PacifiCorp and PGE continue to work through potential federal compliance concerns about whether and how it may be legally appropriate for the utility to make transmission delivery arrangements for generators under the net metering construct envisioned by the state. *See, e.g.*, PacifiCorp's Open Access Transmission Tariff, Section 29.2(vii) (to designate the CSP a network resource requires the utility to file a "statement signed by an authorized officer from or agent of the Network Customer attesting that all of the network resources listed pursuant to Section 29.2(v) satisfy the following conditions: (1) the Network Customer owns the resource, has committed to purchase generation pursuant to an executed contract, or has committed to purchase generation where execution of a contract is contingent upon the availability of transmission service under Part III of the Tariff; and (2) the Network Resources do not include any resources, or any portion thereof, that are committed for sale to non-designated third party load or otherwise cannot be called upon to meet the Network Customer's Network Load on a non-interruptible basis, except for purposes of fulfilling obligations under a reserve sharing program").

the program. These Staff recommendations do not reflect stakeholder input and the release of the Draft Policy Memo on September 13, 2019, has allowed for very limited time to review, analyze, and comment on the major policy shifts. PacifiCorp and PGE's concerns are addressed in greater detail below.

II. Discussion

These policy recommendations are contrary to previous Commission determinations and Oregon statute. The potential rate impact resulting from the Staff Report's recommendations is immense[6] given the size of the CSP. In its report to the Senate Committee on Environmental and Natural Resources and the House Interim Committee on Energy and Environment,[7] the Commission defined "community solar" as "… programs allow[ing] electric customers the opportunity to buy solar energy from a shared solar resource as opposed to installing solar capacity on their own property. *Community solar customers share in the costs, risks, and benefits of solar projects through their utility bill.*"[8] As a preferred attribute to CSP, the Commission included that "[p]rograms shift no costs onto non-participating ratepayers."[9] To emphasize this point, the Commission recommended that the bill language include the following, "[t]o protect non-subscribing ratepayers, all risks and benefits of a community solar project should be borne by the project's owner or developer."[10] In enacting CSP in Senate Bill (SB) 1547, the legislature incorporated the Commission's language regarding cost shifting. Specifically, the legislature directed the Commission to adopt rules that "at a minimum: … minimize the shifting of costs from the program to ratepayers who do not own or subscribe to a community solar project … and protect the public interest."[11] Further, Oregon Revised Statute (ORS) 757.386(6) specifically directs the use of the Resource Value of Solar (RVOS) established by the Commission as the rate credit for CSP, except for "good cause."

In the investigation to consider matters related to CSP implementation, docket UM 1930, the Commission decided a number of policy issues regarding CSP implementation such as bill credit rate and size of the initial capacity tier. Following a transparent process with robust stakeholder engagement through workshops and multiple rounds of comments, the Commission decided to take a measured approach to the CSP implementation. Acknowledging the use of the simple retail rate will result in bill credits significantly higher than published avoided costs, the Commission approved the applicability of the bill credit to 25 percent of the initial capacity tier instead of the 50 percent recommended by Staff. In reaching this decision, the Commission stated "[w]e view this decision as effectively creating a pilot program within our Community Solar program, which we can use to develop learnings that will aide in the finalization of future bill credit rate determinations. Oregon's Community Solar program includes many goals and

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[6] PGE non-participant customers will experience an average rate increase of approximately 0.4 percent.
[7] Docket UM 1746, Commission report to the Senate Committee on Environmental and Natural Resources and the House Interim Committee on Energy and Environment, dated October 26, 2015.
[8] *Id.* at 1 (emphasis added).
[9] *Id.* at 2.
[10] *Id.* at 3.
[11] SB 1547, Section 22(2)(b)(B) and (D).

objectives, we expect the interim bill credit rate we adopt in this ruling to help us understand how these goals and objectives can be best achieved and balanced in the future."[12]

The Staff Report swings wildly away from the measured approach to the CSP that the Commission envisioned just one year ago and the legislative directives in SB 1547. The proposed bill credit escalator coupled with the expansion of the initial capacity tier to 75 percent, shifts approximately $200 million of costs to non-participating customers over the 20-year term of the utilities' power purchase agreements. Further, with the expansion of the initial capacity tier, the pilot nature of the CSP is eliminated, exacerbating initial concerns of the Joint Utilities that the CSP is encroaching in areas left to the exclusive jurisdiction of the federal government, implemented through the Federal Power Act, and therefore increasing the potential for challenges to the CSP by those that are adversely impacted by such cost shifts to non-participating customers of the Joint Utilities; these challenges could include potential securities law challenges.

Circumstances have not changed substantially to warrant such a redesign of the CSP; indeed, the CSP has not even fully launched. Instead of adopting Staff's late forming and severe changes in the Staff Report that would result in significant cost-shifting to non-participating customers of PacifiCorp and PGE, the Commission should implement the CSP design as already approved. This allows the Commission to adapt the program after learning from the 25 percent interim capacity tier implementation to understand how CSP "goals and objectives can be best achieved and balanced in the future."

PacifiCorp and PGE are concerned about the lack of transparency and utility stakeholder engagement involved in developing these significant policy decisions. PacifiCorp and PGE first previewed these policy changes in the Draft Policy Memo. There was no outreach to PacifiCorp and PGE in developing these recommendations. In fact, when first previewed in the Draft Policy Memo, Staff indicated stakeholders could provide ***initial*** comments before the issuance of the final Staff Report but that Staff may not have time to incorporate those comments into its final recommendation.

Other recommendations, including a Commission rule change, are also being proposed with the utilities seeing it for the first time in the Staff Report. As a result, stakeholders have been provided only 11 calendar days to analyze these recommendations and file comments. This stands in stark contrast to the collaborative process that led to the initial program design and the collaborative process used in developing the Staff Report interconnection recommendation, which facilitates CSP projects interconnecting to the utilities' systems while minimizing cost-shifting to non-participating retail customers.

PacifiCorp and PGE support a well-designed pilot program that encourages participation of all our customers, especially our low-income customers; however, this must be weighed against the impacts to all non-participating customers. As proposed in the Staff Report, non-participating customers of PacifiCorp and PGE would experience approximately $200 million in additional costs when compared to the policies that the Commission described and adopted in

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[12] Docket UM 1930, Order 18-177 (dated May 23, 2018) at 4.

Order 18-177. This is a far cry from the design criteria of no cost shifting, that the Commission recommended to the legislature in 2015. The Commission should reject the proposals regarding the escalation of bill credits, tripling the initial capacity tier, program participation measures, and changes to the credit rules contained in OAR §860-088-0170(2).

A. The Commission Should Reject Staff's Proposed Bill Credit Rate

Staff now recommends that the interim bill credit be a base rate, set at the simple retail rate that the Commission approved in Order No. 18-177, plus a 2.18 percent annual escalator. This proposed bill credit rate plus escalator is improper as it is contrary to statute and previous Commission guidance, and not adequately supported in the record.

In ORS §757.386(1)(a), "Community solar project" is defined as "one or more solar photovoltaic energy systems that provide owners and subscribers the opportunity to share the costs and benefits associated with the generation of electricity by the solar photovoltaic energy systems." Staff's recommendation, however, focuses narrowly on ensuring that Project Managers can secure financing, even going so far as to claim that "Project Managers will struggle to secure financing unless the bill credit rate is incentivized so that it's a guaranteed savings product for all participants[.]"[13] This focus on creating a program that is risk free to the developers and results in savings for a premium product for all participants is contrary to the legislature's stated intent that a community solar project is to provide *participants* the opportunity to *share the costs* of solar generating systems as well as the benefits, while minimizing cost-shifting to non-participating customers. The legislature did not say that the intent was to guarantee benefits to participants. Ensuring project financing is not a stated goal of CSP and any attempts to make it a goal of CSP must be harmonized with the statute.

CSP costs not borne by participants will be shifted to nonparticipating customers, including costs arising from a bill credit rate that does not reflect the value of the energy delivered. The legislature provided guidance on this issue in the CSP enabling legislation, directing the Commission to adopt rules that strike the appropriate balance of two competing objectives: "incentivize consumers of electricity to be owners and subscribers" and "minimize the shifting of costs from the program to ratepayers who do not own or subscribe to a community solar project."[14] The Commission acknowledged these legislative directives in Order 18-177, stating that its "objective is to balance the need to provide a rate that will result in projects being developed while doing so with the lowest possible shifting of costs to non-participants."[15]

In the Staff Report, Staff proposes a bill credit rate plus escalator that inappropriately incentivizes CSP participation without consideration of the directive to minimize cost shifting. Staff does this without providing a clear demonstration—including input from and evidence available to all stakeholders—that Project Managers will be unable to finance projects without "a guaranteed savings product for all participants." Recent evidence shows that there is a strong market for renewable attributes in Oregon, including evidence of customers paying a premium

[13] Staff Report (Attachment D), p. 68.
[14] ORS §757.386(2)(b)(A) and (B).
[15] Order 18-177 at 3.

price for these products, making Staff's argument questionable. For example, PacifiCorp's Blue Sky Renewable Energy program and PGE's Green Future program were successful even with a premium price point subscribing approximately 300,000 participants. Furthermore, the Commission has already identified a reasoned approach to determining whether an elevated bill credit rate for CSP participants is warranted: adopt a bill credit rate with limited application to an interim capacity tier and refine it, if necessary, through an iterative approach as the program evolves and more is known, with subsequent tiers.

The legislature's guidance for the bill credit rate directed that, unless good cause is shown, "an electric company shall credit an owner's or subscriber's electric bill for the amount of electricity generated by a community solar project for the owner or subscriber in a manner that reflects the resource value of solar energy."[16] The Commission found good cause to adopt an interim bill credit rate in Order 18-088, but noted that, while an elevated bill credit rate may be necessary to stand up the CSP and ensure that community solar subscription options are made available to customers, "this objective should be achieved at the lowest cost possible to non-participants in order that cost shifting is minimized."[17] In that same Order, the Commission called a bill credit rate based on retail rates "unsatisfactory for the long term,"[18] and clarified its expectation that the interim bill credit rate would be a temporary solution until a "permanent, RVOS-based bill credit rate methodology" is practicable.[19] Expanding the initial capacity tier to 75 percent at the retail rate, plus an escalator, all but guarantees that a bill credit based on retail rates is not "interim" and limits the ability to develop an RVOS-based bill credit.

Since Order 18-177 was issued, the Commission adopted final RVOS methodologies and utilities have filed their RVOS values. Acknowledging that the Commission did find good cause to adopt a bill credit rate that exceeds the RVOS,[20] the rates proposed in the Staff Report are more than double the utilities' currently filed RVOS rates—232% and 268% of RVOS for PacifiCorp and PGE, respectively.[21] Establishing a bill credit rate that diverges so substantially from the RVOS, on which the bill credit rate is supposed to be based, in order to offer participating customers guaranteed savings on a premium product is an inappropriate balancing of the statutory objectives and interpretation of Commission guidance.

The tables below compare the simple retail rate approved in Order 18-177 as calculated by Staff in the Staff Report, the bill credit rate plus escalator proposed for PacifiCorp and PGE in the Staff Report and the PacifiCorp and PGE recently filed RVOS rates.

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[16] ORS 757.386(6)(a); "Resource value of solar energy" is also referred to as RVOS in these comments.
[17] Docket UM 1930, Order 18-088 (dated March 19, 2018) at 4.
[18] *Id* at 5.
[19] *Id* at 4.
[20] Order 18-088.
[21] *See* Tables 1 and 2 below.

Table 1: Comparison of Rates for PacifiCorp	
Source of Rate	**Rate**
Simple Retail Rate	$0.0977/kilowatt hour (kWh)
Bill Credit Rate with Escalator – Staff Report	$0.1152/kWh*
Filed RVOS Rate	$0.04964/kWh**
* levelized across the 20-year applicable term	
** does not include administrative costs and environmental compliance values	

Table 2: Comparison of Rates for PGE	
Source of Rate	**Rate**
Simple Retail Rate	$0.1123/kWh
Bill Credit Rate with Escalator – Staff Report	$0.1328/kWh*
Filed RVOS Rate	$0.04954/kWh**
* levelized across the 20-year applicable term	
** does not include administrative costs and environmental compliance values	

As shown in the above tables, for both PacifiCorp and PGE, the bill credit rate with escalator is approximately 18 percent higher than the simple retail rate adopted by the Commission in Order 18-177 and calculated by Staff in the Draft Policy Memo. Staff does not offer sufficient justification for its recommendation that the Commission adopt bill credit rates that are 18 percent *higher* than the rates that the Commission has already recognized as "significantly higher" than the published and approved avoided cost rates,[22] and that are more than double the recently filed RVOS rates for PacifiCorp and PGE.[23]

B. An Expansion of the Interim Capacity Tier is Not Warranted at This Time

In the Staff Report, Staff recommends that, rather than adhering to Order No. 18-177 and apply the retail bill credit rate to the first 25 percent of a utility's initial capacity tier, the proposed bill credit rate plus escalator be expanded to 75 percent of the initial capacity tier. This proposed expansion of the interim capacity tier creates substantial cost shift concerns and changes the pilot nature of this interim tier.

[22] Order 18-177 at 3, ("The Simple Retail rate proposal will result in bill credits that are higher than the utility's published and approved avoided costs. Though we recognize that the values reflected in avoided cost pricing are not the same as those we would seek to incorporate in RVOS values, the fact that the Simple Retail rate proposal will result in bill credits significantly higher than published and approved avoided costs indicates to us that the use of this interim rate should be limited, until such time as we have more information with which to judge its reasonableness.")

[23] See Docket UM 1910, Order 19-021 (dated January 22, 2019) for PacifiCorp RVOS values and Docket UM1912, Order No. 19-023 (dated January 22, 2019) for PGE's RVOS values.

1. Increasing the size of the CSP pilot program removes the opportunity to adapt rates to minimize the impact on non-participants through iterative adjustments

Expanding the interim capacity tier to 75 percent of the initial program capacity would lock in approximately 120 megawatts (MWs) worth of energy purchases at a bill credit rate that would result in a substantial cost shift to non-participating customers (and significantly exceeds the recently filed RVOS rates on which the legislature intended the bill credit rate to be based). The proposed bill credit rate plus escalator and interim capacity tier expansion policies would cause $72 million and $129.9 million of additional costs to be shifted onto PacifiCorp's and PGE customers, respectively, as compared to the retail rates adopted by the Commission in Order 18-177 and calculated by Staff in the Staff Report.

Staff's concern about the ability of Project Managers to secure financing is unsupported. The Staff Report neither provides any evidence that those concerns are warranted, nor establishes that the inability of some unknown number of potential Project Managers to secure financing will hinder the successful development of community solar projects. Importantly, even if evidence were presented to support this claim, the Staff Report does not explain why a Project Manager's ability to secure financing outweighs the clear statutory directive to minimize cost shifting to non-participating customers. This is an inappropriate basis on which to obligate non-participating customers to hundreds of millions of additional costs.

Staff also appears to support its proposals to raise the bill credit rate and expand the interim capacity tier by citing the need to cover program administration costs within an artificially created deadline. In the discussion regarding administrative fees, the Staff Report proposes a transition between startup costs and ongoing administrative costs where all utility customers are responsible for any shortfall in administrative fee collections. This transition deadline is set at 24 months following the launch of the precertification window. This 24-month deadline for transitioning off of customer support for administrative costs is then used to justify the selection of the elevated bill credit rate and the expanded 120 MW interim capacity tier. The flawed basic reasoning offered by Staff is that the bill credit rate must be sufficiently high to eliminate Project Manager risk altogether and guarantee customer participation, and the interim capacity tier must be large enough that a total of 80 MWs is installed at this 24-month transition deadline.[24]

While PacifiCorp and PGE appreciate the concerns expressed in the Staff Report and goal to minimize long-term administrative cost subsidies to the program, raising the compensation rate and expanding the interim capacity dramatically increases non-participating customer costs over-all for the program. As suggested above, the impact of the retail rate plus 2.18 percent escalator and the expanded interim capacity tier on PacifiCorp's customers is approximately $31million per 40 MW block, or $93.1million for the full 120 MWs of the expanded interim capacity tier. The impact to PGE's customers is approximately $43.3 million

[24] *See* Staff Report (Attachment D) at 83.

per 40 MW block, or $129.9 million for the full 120 MWs of the expanded interim capacity tier. This compares to the administrative maximum cost[25] of approximately $2.3 million annually shared across the utilities, or $920,000 for PacifiCorp and $1.3 million for PGE. In short, this proposal costs customers approximately $200 million between PacifiCorp and PGE in hopes of saving customers an ever-shrinking portion of $2.3 million annually. This result is not reasonable. A simple solution is to maintain the 25 percent initial capacity tier and allow projects to develop naturally and conduct the proposed administrative cost review at 24 months, rather than drive to a much more expensive elevated capacity target in order to reduce administrative costs a fraction of the size. Based on the information collected, the Commission can then decide whether program changes are necessary.

2. Increasing the size of the CSP pilot program undermines the good-faith basis on which the parties have endeavored to create a workable first capacity tier in a timely manner.

The parties have worked hard to overcome the interconnection challenges presented by CSP implementation, including participation in a series of workshops held this past summer to get CSP off the ground and operational. PacifiCorp and PGE continue to work through the interconnection challenges in good faith, with the understanding that, with a 25 percent capacity tier the issues are at the stage of being resolved only on an interim basis. As noted above, the issues include potential jurisdictional concerns that may thread through the interconnection elements of the program, particularly if the state-created "virtual" netting construct is ultimately found to in fact be a wholesale sale, rendering the interconnection service provided to community solar generators likewise FERC-jurisdictional and not eligible for net metering-like interconnection processes. PacifiCorp and PGE nevertheless have been willing to suspend their concerns about many of these issues on the premise that the first capacity tier is small, and thus may avoid the larger implications that may be raised by problematic program design.[26] In short, PacifiCorp and PGE have been relying on Order 18-177 about program size and the "pilot" nature of the smaller first interim capacity tier to put their full weight behind expediting the program and agreeing, among other things, to a potential interconnection structure that is designed to reduce the likelihood, but not completely guarantee against, potentially significant cost shifts or federal complaints.

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[25] The contract for services between the Program Administrator and the Department of Administrative Services sets maximum annual reimbursement for ongoing costs at approximately $2.3 million.

[26] In March 2017, during the informal process in rulemaking docket AR 603, PacifiCorp and PGE submitted comments to Staff addressing several legal issues associated with the CSP, including securities issues and whether the program could be deemed a net metering program for purposes of state jurisdiction over the transaction. PacifiCorp and PGE cautioned Staff that relying on virtual net metering was potentially risky from a jurisdictional perspective. At that time, the initial capacity tier was proposed to be 1 percent of load. See Attachment A for these informal comments by PacifiCorp and PGE. These concerns earlier offered by PacifiCorp and PGE have been raised by the utility industry in general in other proceedings. *See* EEI Comments submitted in FERC docket in EL16-107, dated October 7, 2016, regarding Maryland's implementation of its community solar program.

Thus, despite the fact that some issues still require resolution,[27] PacifiCorp and PGE were comfortable going forward with a CSP that relied on the state's netting requirements based on their understanding that the initial pilot program would be limited in size and subject to potential adjustment and course correction before a full-scale roll-out. Staff now effectively recommends bypassing a pilot program by expanding the interim capacity to encompass 75 percent of the initial capacity tier—over 120 MWs of CSP generation.

PacifiCorp and PGE respectfully ask the Commission to maintain the initial 25 percent capacity tier. The first tier should continue to be small enough to workshop, pilot, and implement in a way that will not create undue concerns about the impacts of problematic program design, while still allowing the Commission to get the program off the ground. PacifiCorp and PGE also ask the Commission to affirm that the next program tier will allow an opportunity for review and correction of any problematic program design elements as the program matures.

C. Simplification of Credit Rules Contained in the Oregon Administrative Rules

The Staff Report recommends that the Commission waive OAR §860-088-0170(2) requirements and adopt the following bill mechanics:

(1) Calculate a participant's total monthly bill credit by multiplying the bill credit rate by the
participant's share of total project generation in the month, which will be referred to as the "total bill credit";

(2) If the value of the total bill credit exceeds the participant's total utility bill amount (in dollars), less any other on-bill repayment expenses, the excess bill credit amount (in dollars) is carried forward as a positive balance on the participant's account, which is referred to as the carry-over bill credit value; and

(3) At the end of the annual billing cycle, any remaining carry-over bill credit value (in dollars) attributable to CSP participation must be donated to the low-income programs of the electric company serving the participant.

PacifiCorp and PGE disagree with the recommended waiver of OAR §860-088-0170(2) because the new bill mechanics, as written, change the structure of the program from an energy netting program to a program that caps the amount of bill credit. This structure has the potential

[27] PacifiCorp and PGE continue to work through potential federal compliance concerns about whether and how it may be legally appropriate for the utility to make transmission delivery arrangements for generators under the net metering construct envisioned by the state. *See, e.g.*, PacifiCorp's Open Access Transmission Tariff, Section 29.2(vii) (to designate the CSP a network resource requires the utility to file a "statement signed by an authorized officer from or agent of the Network Customer attesting that all of the network resources listed pursuant to Section 29.2(v) satisfy the following conditions: (1) the Network Customer owns the resource, has committed to purchase generation pursuant to an executed contract, or has committed to purchase generation where execution of a contract is contingent upon the availability of transmission service under Part III of the Tariff; and (2) the Network Resources do not include any resources, or any portion thereof, that are committed for sale to non-designated third party load or otherwise cannot be called upon to meet the Network Customer's Network Load on a non-interruptible basis, except for purposes of fulfilling obligations under a reserve sharing program").

to have a disparate impact on customers based on their CSP participation structure. It specifically may disadvantage customers that choose to participate in the CSP as owners. In that situation, CSP owners will have fewer charges on their bill that can be offset, increasing the likelihood that there is a carry-over bill credit that would need to be donated. In the example provided in Table 3 below, with a similar CSP share generation credit and power usage, CSP owners would have to donate $87.70 at the end of the month whereas participants with different subscription structures would not have any carry-over bill credit that needs to be donated. Table 3 below illustrates the potential impacts of adopting the bill mechanics proposed by Staff on different CSP ownership/subscription structures.

Table 3: Potential Impacts of the Staff Report's Bill Mechanics.

Description	Owner-Paid for participation upfront	Subscriber - Subscription Fee 50% of Credit	Subscriber - Subscription Fee 90% of Credit
Basic Charge	$ 10.00	$ 10.00	$ 10.00
Customer Usage- 1,000 kWh/ $0.0977	$ 97.70	$ 97.70	$ 97.70
CSP Share Generation Credit- 2,000 KWh/ $0.0977	$ (195.40)	$ (195.40)	$ (195.40)
CSP Subscription Fee	$ -	$ 97.70	$ 175.86
Monthly Billing	$ (87.70)	$ 10.00	$ 88.16
Low income donation	$ 87.70	$ -	$ -

PacifiCorp and PGE suggest that any modifications to the bill crediting structure continue to contain an annual comparison between the customers kWh usage and the kWh generation from their share of the CSP. This will ensure that the choice of participation model does not negatively impact the benefit a customer receives from the program.

D. PGE-only Section: Guaranteed Low-Income Participant Savings of 20 Percent can be achieved without cost-shifting to non-participants

The Staff Report describes the efforts undertaken to ensure that low-income subscriptions are designed so that participants do not experience a net increase in utility bills due to their participation in the program. Staff's recommendation is to require Project Managers to provide low-income participants with at least 20 percent subscription savings. Staff's recommendation is based on the assumption that CSP managers would be able to provide such savings and still earn an acceptable internal rate of return[28] if the Commission adopted Staff's proposal to expand the interim capacity tier and adopt an escalated bill credit based on the retail rate. While PGE is not opposed to providing low-income participants with bill savings to the extent that the Commission determines bill discounts are legal and necessary,[29] PGE believes that those savings should be subsidized by other community solar participants that are not low-income through higher subscription fees rather than the utility's non-participating customers. Staff's proposed

[28] Staff identified 8 percent Internal Rate of Return as a proxy return for community solar projects to be made available to participants.

[29] Guaranteeing bill savings could also raise securities law issues if participants have an expectation of profit by participating in the program (e.g., a bill discount).

approach to guaranteed savings requires the Commission to adopt the escalated bill credit proposal which will cause significant cost shifting onto all non-participating customers, including low-income customers. As such, PGE is supportive of removing barriers for low-income customer participation[30] and support more dialogue to develop a variety of ways to ensure low-income participation and savings whilst complying with the statutory intent to minimize cost-shifting to non-participants.

E. Lack of Utility Engagement With Respect to Non-Interconnection Policy Decisions

Staff states "[t]his public meeting memo represents the culmination of several months of work, multiple rounds of stakeholder comments, and Staff's final recommendations for each of the four CSP policy areas."[31] PacifiCorp and PGE agree with this statement as it relates to the Staff Report's recommendation regarding interconnection. With respect to the interconnection issue, there was robust stakeholder engagement that included a number of stakeholder workshops and multiple rounds of comments. In the end, with exception to the increase in the interim capacity tier to 75 percent of program capacity, the Staff Report's recommendation regarding interconnection reflects the input from all stakeholders during the course of about three months. Furthermore, the recommendation balances the goals of CSP, including limiting cost-shifting to retail customers.

However, there was little time for meaningful stakeholder engagement on Staff's recommendations regarding the remaining policy issues of bill credit, low-income participation requirements and transition between start-up and on-going costs. These were first provided to stakeholders in the Draft Policy Memo issued on September 13, 2019, just three weeks before the Staff Report was issued. Although stakeholders provided initial comments,[32] the final policy recommendations appear to reflect no stakeholder input except for input received from developers.[33] In an effort to provide input regarding the significant revisions to the CSP design, PacifiCorp and PGE provided initial comments on September 30, 2019. However, the Staff Report does not seem to address PacifiCorp and PGE concerns or acknowledge receipt of their initial comments.

The result of the lack of transparency[34] and stakeholder input to the development of these policy recommendations results in a one-sided impact to PacifiCorp and PGE non-participating customers and changes the pilot nature of CSP. The policy recommendations trade increased participation of low-income customers and returns and risk reduction for developers for higher costs to non-participating customers. Given the significant CSP design changes proposed in the Staff Report, a more open process for stakeholder input would have allowed PacifiCorp and PGE

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[30] Historically, issues like credit scores, bill payment history, exit fees, and up-from fees with long paybacks have represented barriers for low-income customers to access renewable energy program.

[31] Staff Report at 3.

[32] *See* Commission Docket UM 1930, reflecting PacifiCorp and PGE Joint Comments filed September 30, 2019, and Fleet Development Comments filed October 11, 2019.

[33] See for example, Staff Report (Attachment D) at 66.

[34] Staff declined to provide the Project Managers pro-formas on which Staff analysis it is relying upon stating confidentiality concerns.

to share cost-shifting concerns, and help identify alternative approaches earlier to inform the recommendations made in the Staff Report.

III. Conclusion

PacifiCorp and PGE acknowledge the efforts undertaken by Staff so that community solar may be launched with success in Oregon. However, Staff's recommendations do not reflect the balance that the statute requires or the Commission's measured approach to CSP. Returning to the 2015 design criteria, Staff's proposals contain significant cost shifts, will not create an adaptive CSP program, and do not favor ease and efficiency in its administration. Accepting approximately $200 million in cost impacts on non-participating customers in favor of guaranteed bill savings for participants and the elimination of Project Manager risks is not the appropriate balance of interests. PacifiCorp and PGE recommend that the Commission reject Staff's recommendations regarding calculation of bill credits, incorporating an escalator to the residential retail rate, tripling the interim capacity tier, the declared need to guarantee bill savings to ensure program participation, and that the Commission waive OAR §860-088-0170(2) and adopt new bill credit mechanics. PacifiCorp and PGE instead recommend implementing CSP based on the Commission's previous guidance in Order 18-177. After gaining experience in the CSP roll out, the Commission can revisit these issues as needed and base any changes on information learned and stakeholder input.

Signed this date 15 October, 2019

Jay Tinker

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Director, Regulatory Policy & Affairs

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October 26, 2015

Senate Committee on Environment and Natural Resources
900 Court St NE
Salem, OR 97301

House Interim Committee on Energy and Environment
900 Court St NE
Salem, OR 97301

Re: Attributes for the Design of a Community Solar Program

Dear Members:

House Bill 2941, enacted last session, directed the Public Utility Commission (PUC) to hold proceedings and recommend a set of preferred attributes for the design of a community solar program. We were directed to report back to the Legislature by November 1, 2015.

We held two public workshops and three rounds of public comment. Below, we offer our recommendations for the definition of community solar, the attributes and features of the program that should be incorporated in any proposed legislation, and those attributes or features that should be addressed and decided by the PUC in future rulemaking.

Definition of Community Solar

We recommend the following definition for community solar:

> Community solar programs allow electric customers the opportunity to buy solar energy from a shared solar resource as opposed to installing solar capacity on their own property. Community solar customers share in the costs, risks, and benefits of solar projects through their utility bill.

Preferred Attributes and Features

In developing our recommended community solar program attributes and features, we used the following criteria:

- Programs should stress providing fair access to Oregon households and small businesses that do not have the ability to install solar on their own property.

- Programs should shift no costs onto non-participating ratepayers.

- Programs should be designed for easy and efficient administration.

- Programs should allow for adaptations as we gain experience.

If legislation is considered, we recommend the following program attributes and design features be incorporated into bill language:

Scope: Community solar programs should be available to all electric customers statewide and not just the investor-owned utility service areas. We limit our recommendations, however, to public utilities subject to our regulation under ORS 757.005.

Eligibility: Residential and small commercial customers should be eligible to participate in a community solar project.

Program Size: An initial capacity cap of 0.5 percent of 2014 peak load should be assigned for each utility, with provisions to allow the PUC to adjust the cap after a two-year initial phase.

System Size: Eligible projects should have a capacity of between 25 kilowatts to 2 megawatts.

Subscription Size: An eligible customer should be allowed to subscribe up to the customer's average annual load. Any bill credits associated with energy generation that are in excess of annual energy use at the subscriber's site should be donated to low income programs.

Bill Credit Rate: The bill credit should equal the resource value of solar as determined by the PUC, unless the PUC finds good cause to deviate from that rate and apply a different rate.

System Location: Community solar projects should be allowed to be located anywhere in Oregon.

System Ownership: Investor-owned utilities should be permitted to own and operate a community solar project subject to conditions established by the PUC to protect the public interest and to ensure that non-subscribing customers are held harmless.

Cost and Risk Shifting: To protect non-subscribing ratepayers, all risks and benefits of a community solar project should be borne by the project's owner or developer.

Cost Recovery: Start-up costs incurred by utilities during community solar project development should be borne by all ratepayers. On-going administrative costs should be borne by the project's owner/developer and subscribers.

Ownership of RECs: The ownership of all Renewable Energy Certificates (RECs) generated by a community solar project should generally remain with the subscribers to that project.

Low Income Customers: The PUC should be directed to explore and implement ways to promote full and fair access to community solar projects by low income Oregonians, including but not limited to reserving a certain amount of capacity for those ratepayers.

Report: The PUC should be directed to provide a report on the status of the community solar program following an initial two-year phase and recommend necessary adjustments to improve the program.

We recommend that all other program attributes and features be developed and decided through PUC rulemaking. These include consumer protection measures, contract terms and conditions, product design, subscription pricing, and other design features.

We are available at any time to discuss our recommendations.

Respectfully,

Susan K. Ackerman Chair	John Savage Commissioner	Stephen M. Bloom Commissioner

AR 603

PacifiCorp and Portland General Electric Company's Informal Comments Re: DOJ Memo on Legal Issues Related to Community Solar Programs under SB 1547

PacifiCorp and Portland General Electric Company (PGE) appreciate the opportunity to provide comments on the January 26, 2017 Interoffice Memo regarding AR 603 Legal Issues (the Legal Memo) and the questions raised at the February 7, 2017 stakeholder meeting. Successful implementation of the community solar program required by Senate Bill (SB) 1547 is a priority for PacifiCorp and PGE, and minimizing legal risk, administrative burden, and undue cost shifting are guiding principles for the Companies in examining potential community solar program designs. Recognizing that there may be multiple legal pathways for development of Oregon's community solar program, these comments focus on identifying the strongest possible legal positions that are also consistent with the policy goals of a successful community solar program. We acknowledge that the unique circumstances and tolerances for legal risk of the different utilities may warrant different program design characteristics. PacifiCorp and PGE also acknowledge that many aspects of the final community solar program remain unknown at this time and that resolution of those details may result in refined analysis of the potential interactions between program design and legal risk.

Structure of Community Solar Program

The Legal Memo identifies three possible structures for a community solar program under SB 1547 that would resolve concerns over FERC preemption of the Oregon Public Utility Commission's (OPUC) ability to establish rates or pricing for the program: (1) virtual retail netting plus a Public Utility Regulatory Policies Act (PURPA)[1] power purchase agreement (PPA) for unsubscribed energy; (2) PURPA PPA plus customer bill credit; and (3) bilateral contracts filed with the Federal Energy Regulatory Commission (FERC) plus customer bill credit.

PacifiCorp and PGE's preferred approach is the second option--to establish the community solar program under PURPA. The Commission has clear jurisdiction to set wholesale avoided cost prices under PURPA;[2] therefore, if the design of the community solar program includes a wholesale sale, the rate set by the Commission must be set under the Commission's PURPA authority. Under this approach, the utility and the community solar project developer would enter into a QF contract, modified for community solar, in which the developer/project owner would sell all net output[3] to the utility in exchange for bill credits to subscribers, with the unsubscribed energy or value of unsubscribed energy being allocated to low energy customers.[4] The utility purchases the net output of the facility, as required by PURPA at

[1] 16 U.S.C. § 2601 *et seq.*
[2] *FERC v. Mississippi*, 456 U.S. 742, 746-51, 102 S.Ct. 2126 (1982).
[3] In this instance, "net output" refers to all the output less the station service. This is in contrast to the purchasing of all the output less the subscribed energy.
[4] See discussion of Section 22, 5(b) language, below re: low-income residential customers.

the avoided cost rate.[5] This approach relies on the clear jurisdiction of the Commission to implement PURPA and set appropriate avoided cost pricing while also side-stepping the unsettled territory of federal and state jurisdiction in the context of virtual net metering (see discussion below). In addition, the Commission has already considered many policy issues in the PURPA context that are likely to be raised in the context of a community solar program and can benefit from this prior deliberation.[6]

Though FERC's disclaimer of jurisdiction over "net metering" arrangements establishes some basis for applying a virtual retail netting approach to Oregon's community solar program, it is unclear whether the same logic would apply when energy is consumed in a different location from where it is generated.[7] The virtual retail netting structure tests the limits of federal/state jurisdiction—the station service analogy cited by the Legal Memo to disclaim FERC jurisdiction over state net metering fits in the context of private solar generation located on the roof of the customer. It remains untested, however, whether that analogy withstands scrutiny if the customer and the generation are nowhere near one another.[8] Indeed, taken to its extreme, a virtual retail netting program of the type identified in the Legal Memo could disrupt the balance of state and federal jurisdiction by expanding state jurisdiction to every scenario where a customer claimed to be virtually netting their consumption against generation from a resource, regardless of the location of the resource.

In addition, the virtual retail netting approach is problematic, because it could potentially perpetuate the shift of fixed costs from participating to non-participating customers. In particular, PacifiCorp and PGE are concerned with the notion that a utility's system can be leaned on to support virtual transactions without cost to, or impact on, non-participating customers. In "virtual" transactional situations, the risk of establishing and applying a pricing scheme that fails to accurately capture the costs to the utility and non-participating customers is material. The Commission should also carefully consider the potential of such a precedent being expanded to un-related programs, such as conventional net metering or other programs where it finds cost shifting to exist.[9]

Moreover, there are other potential legal concerns with the virtual retail netting approach proposed by Staff. SB 1547 requires that a utility enter into a 20-year PPA; however, there likely is no PPA between the utility and the subscriber. Additionally, the Legal Memo suggests

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[5] As the Legal Memo points out, it may be possible for an avoided cost rate for subscription payment to be developed based on a proxy community solar resource.

[6] *See generally* Docket No. UM 1610.

[7] SB 1547, Sec. 22 (3)(b) specifically allows projects to be located anywhere in the state.

[8] In *PJM Interconnection*, LLC, 94 FERC ¶ 61,251 (2001) relied upon by the Legal Memo, the provision of remote 3rd-party supplied station service did not avoid FERC regulation because of netting, but rather, because the energy was used by the end user and thus not a wholesale sale: "Here, the generator is not self-supplying its own station power needs, but is using another party's generation facilities. Thus, the provision of station power under these circumstances involves a sale of energy by a third party that is not appropriately accounted for by netting. Moreover, the energy being sold is not sold for resale, and therefore it is not a transaction which we can regulate under the FPA. *Id.* at 61891

[9] *See, e.g.*, Docket No UM 1758 (net metering examined as an incentive program).

an annual netting period. To date, however, FERC has only found monthly netting as legally sufficient, and has not expanded netting to encompass an annual period.[10]

The third approach identified in the Legal Memo, the bilaterally-negotiated approach, is unlikely to withstand legal scrutiny and also unlikely to result in development of a successful program. The market-based rate program to establish rates for a state community solar program is likely problematic because market-based rates are premised on a *voluntary* transaction. As mentioned above, SB 1547 *requires* the utility to enter into a 20-year PPA; state determinations of rates for sale and the length of a mandatory contract appear inconsistent with the market-based rate approach. Use of the market-based rate approach would also require each community solar project developer to obtain market-based rate authority, which could have a chilling effect on project developer participation.

Dormant Commerce Clause.

PacifiCorp and PGE support implementation of the Community Solar program in such a way that minimizes potential legal infirmities. Thus, to the extent the in-state location requirement for community solar projects is potentially unconstitutional under the Dormant Commerce Clause, PacifiCorp and PGE recommend placing additional restrictions on the location of community solar projects to cure the constitutional issue. For example, limiting community solar projects to the service territories of PacifiCorp, Idaho Power, or PGE, or requiring some nexus between the location of the project and the customer subscribers (e.g., within the same or adjacent county). In addition to addressing potential Dormant Commerce Clause issues, limiting community solar projects to locations that bear some nexus to the participating customers aligns with the purpose of a *community* solar program—to bring renewable solar energy into the community that is seeking such a resource. Finally, locating community solar projects close to participating customers has the potential to reduce transmission and interconnection expenses, ultimately driving down project costs and increasing the likelihood of a successful community solar program.

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[10] *See MidAmerican Energy Co.*, 94 FERC ¶ 61340 (2001). *See also, California Independent System Operator Corp.*, 126 FERC ¶ 61,050 (2009), *PJM Interconnection, LLC*, 94 FERC ¶ 61,251 (2001), *clarified and reh'g denied*, 95 FERC ¶ 61,333 (2001); *PJM Interconnection LLC*, 95 FERC ¶ 61,470 (2001); *KeySpan-Ravenswood, Inc. v. New York Independent System Operator, Inc.*, 99 FERC ¶ 61,167 (2002), *order on reh'g*, 100 FERC ¶ 61,201 (2002); *KeySpan-Ravenswood, Inc. v. New York Independent System Operator, Inc.*, 101 FERC ¶ 61,230 (2002), *reh'g denied*, 107 FERC ¶ 61,142 (2004), *clarified*, 108 FERC ¶ 61,164 (2004); *Midwest Independent Transmission System Operator, Inc.*, 106 FERC ¶ 61,073 (2004), *order on reh'g*, 110 FERC ¶ 61,383 (2005). Netting over a period means that total station power consumption is subtracted from total gross output during a given period, known as the "netting interval." When a monthly netting interval is used, a generator's total monthly consumption of station power is subtracted from (netted against) its total monthly energy production in order to determine if it is "net positive" or "net negative" for the month. As long as a generator produces more energy over the entire month than it consumes as station power, it is "net positive," even if, during a specific hour, it consumed more station power than it generated. June 22 Order, 111 FERC ¶ 61,452 at P 16-17; *accord PJM II*, 94 FERC ¶ 61,251 at 61,891-92.

Review Section 22, 5(b) language.

Section 22, 5 of SB 1547 reads as follows:

(a) A *project manager may offer* proportional ownership in or proportional subscriptions to a community solar project in any amount that does not exceed a potential owner's or potential subscriber's average annual consumption of electricity.
(b) Any value associated with the generation of electricity *in excess of an offer* to own or subscribe to a community solar project as limited by paragraph (a) of this subsection must be used by the electric company procuring electricity from the community solar project in support of low-income residential customers of the electric company.

Read together, it appears that 5(a) addresses the size of offerings that can be made to potential owner's or subscriber's and 5(b) addresses what the project manager must do with any value associated with electricity in excess of the offerings referenced in 5(a) (i.e., unsubscribed electricity). Neither 5(a) nor 5(b) address the treatment of electricity generation owned or subscribed to by an owner or subscriber in excess of the average annual consumption of the owner or subscriber. A reasonable reading of Section 22, 5(b) is that the value of unsubscribed energy (generation) from a community solar project is to be used for low-income residential customers of the electric company.

In contrast, Oregon's net metering law has language that specifically addresses the treatment of generation in excess of use. The language in ORS 757.300(3)(d) is markedly different than the language used by the legislature in SB 1547:

> For the billing cycle ending in March of each year, or on such other date as agreed to by the electric utility and the customer-generator, any remaining unused kilowatt-hour credit accumulated during the previous year shall be granted to the electric utility for distribution to customers enrolled in the electric utility's low-income assistance programs[.]

Given the differences between the language used in ORS 757.300(3)(d) and Section 22, 5(b) of SB 1547, it is reasonable to assume that the legislature intended something different than ORS 757.300(3)(d) when drafting Section 22, 5(b).

Securities.

A main purpose of securities regulation is consumer protection. To that end, if a product is determined to be a security under state or federal law, the seller of the security is subject to a wide variety of requirements, including disclosure requirements. In 2014, Oregon exempted renewable energy cooperatives from state securities filing requirements.[11] Federal securities regulation, unfortunately, provides no similar blanket exemption.

In 2009, Stoel Rives created a memorandum (the Stoel Rives Memo) for the National Renewable Energy Laboratory addressing securities law issues relating to community solar. The Stoel Rives Memo is attached to these comments and provides a thorough overview of securities

[11] *See* Senate Bill 1520-B; *see also* ORS 59.025(12).

law risks associated with community solar programs and offers several solutions to minimize the risk of securities regulation:

- The customer's participation in the community solar project should be structured to look similar to a "standard" purchase of solar energy. For example, the rate charged should be a "generally applicable market rate per unit" that does not pay for investment in the project; also, rather than making up-front payments, the customer could be charged after solar power is provided.
- The amount of credit received by a participating customer should not vary based on the amount of energy generated by the community solar project. For example, rather than buying a percentage or proportionate share in the community solar project, the customer could buy a set number of 1 kilowatt blocks of energy. In this way, the amount of credit received each month by the participating customer would not be tied to the performance of the facility.
- Opportunities for customers to make a profit, including purchasing power for less than the normal market rate for solar power, should be avoided.
- Transfer for new owners should be appropriately limited to ensure that customers cannot utilize transfers to generate profit.

Whether an offering constitutes a security is a fact-specific examination, but the Commission can and should adopt rules that limit the likelihood of securities regulation.

Renewable Energy Credits.

With regard to renewable energy certificates, SB 1547 requires that RECs go to the participating customers.[12] The Commission should adopt rules that prohibit customers from reselling the RECs or that require project developers to retire the RECs on behalf of participating customers. In addition to minimizing the risk of securities regulation, limiting the marketability of community solar RECs is consistent with the purpose of a community solar program—providing customers with access to renewable solar energy. Participating customers cannot claim they are receiving renewable energy if the customers do not maintain ownership of the RECs or if the RECs are not retired on the customer's behalf.

[12] If the RECs are not transferred to the utility, the Commission-determined community solar avoided cost rate paid to subscribers would need to take into account that fact.