ITEM NO. 1

PUBLIC UTILITY COMMISSION OF OREGON
STAFF REPORT
PUBLIC MEETING DATE: March 5, 2018

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

DATE: February 26, 2018

TO: Public Utility Commission

FROM: Caroline Moore CM

JPB for JE JPB
THROUGH: Jason Eisdorfer and JP Batmale

SUBJECT: OREGON PUBLIC UTILITY COMMISSION STAFF: (Docket No. UM 1930) Staff report on alternate bill credit rate considerations for Community Solar

STAFF RECOMMENDATION:

Informational filing - no recommendation.

DISCUSSION:

Issue

Informational report on the context and considerations for investigating an alternate bill credit rate for Oregon's Community Solar program.

Applicable Rule or Law

Section 22 of Senate Bill (SB) 1547, effective March 8, 2016, directs the Public Utility Commission (Commission) to establish a program that provides electric customers with the opportunity to share the costs and benefits of solar generation. Community solar participants bear a portion of the cost to construct and operate a solar facility and receive a bill credit from their electric company for their portion of the solar facility's generation.

The legislation outlines several objectives for the Commission in developing the program, which include:

- Incentivize consumers of electricity to be owners or subscribers;
- Minimize the shifting of costs from the program to ratepayers who do not own or subscribe to a community solar project;

- Where an electric company is the project manager, protect owners and subscribers from undue financial hardship; and
- Protect the public interest[1]

SB 1547 directs the Commission to establish the rate at which Community Solar participants are credited that reflects the resource value of solar (RVOS). The Commission is able to adopt an alternate rate with good cause. The legislation states:

1. *"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. For purposes of this paragraph, the commission shall determine the resource value of solar energy."*[2]
2. *"The commission may adopt a rate for an electric company to use in crediting an owner's or subscriber's electric bill other than the rate described in paragraph (a) of this subsection if the commission has good cause to adopt the different rate."*[3]

Finally, the legislation provides the Commission authority to suspend the program for good cause.[4]

On June 29, 2017, The Commission adopted formal rules for Oregon's Community Solar Program (CSP) through Order No. 17-232. That order adopted Division 88 of Chapter 860 of the Administrative Rules, which includes the following directive to establish the bill credit rate based on the RVOS:

> *"Unless otherwise determined by Commission order, the bill credit rate for a project will be based on the resource value of solar applicable to that project at the time of pre-certification and will apply for a term no less than the term of any power purchase agreement entered into pursuant to OAR 860-088-0140(l)(a)."*[5]

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[1] Enrolled Senate Bill 1547 Section 22, (2)(b) A – D.
[2] *Ibid*, Section 22 (6)(a).
[3] *Ibid*, Section 22 (6)(b).
[4] *Ibid*, Section 22 (2)(c).
[5] Oregon Administrative Rules 860-088-0170 (1)(a).

Order No. 17-232 provides additional guidance on the temporal interaction between the Community Solar bill credit rate and development of the resource value of solar.[6] While RVOS was under development at the time program rules were adopted, the Commission agreed with Staff that it was premature to adopt an interim rate and directed Staff to, "monitor the progress of docket UM 1716 and to recommend appropriate action if it becomes apparent that delay in establishing a bill credit rate is delaying program launch."[7]

Analysis

Background

The Commission's Order No. 17-232 adopted Community Solar Program rules and directed Staff to commence program implementation and identify a third-party administrator through a competitive bidding process. In a subsequent ruling, Order No. 17-372, the Commission adopted Staff's recommended next steps for implementation, including the formation of sub-groups to begin identifying and addressing relevant and timely implementation issues alongside efforts to select the Program Administrator (PA). Stakeholders formed four sub-groups to investigate specific, high-priority implementation issues:

1. Funding, Data and Financial Exchange, Billing Tariffs
2. Project Details
3. RVOS and Bill Credit Determination
4. Low Income

The RVOS and Bill Credit Determination sub-group discussed timing considerations for utilizing RVOS as the community solar bill credit rate. The sub-group also considered the establishment of an alternate to RVOS. With regards to an alternate rate some stakeholders argued that, regardless of timing, the value of the RVOS might not be sufficient to support program success. The sub-group presented findings in a report to

[6] The Commission opened Docket No. UM 1716 Investigation to Determine the Resource Value of Solar on January 27, 2015. The docket opened as a result of recommendations provided in the following reports: Investigation into the Effectiveness of Solar Programs in Oregon, July 1, 2014; and Solar Photovoltaic Volumetric Incentive Program, January 1, 2015. The Investigation into the Effectiveness of Solar Programs referred to the resource value of solar as "the value of the benefits solar generation brings to the utility system and electricity ratepayers in general. It does not include potential social benefits such as improved environmental quality." As of June 2017, UM 1716 was ongoing and the RVOS was not available. As of the date of this report, the RVOS remains under development.

[7] Order 17-232, p. 8.

Staff in December 2017.[8] Staff relayed the sub-group findings at the January 30, 2018 Public Meeting.[9]

Staff recommended further evaluation of the impact of RVOS timing on CSP launch.[10] Specifically, Staff proposed to issue a report by April 17, 2018 recommending whether and how an interim bill credit should be established. Several parties commented on Staff's recommendation, including Bonneville Environmental Foundation (BEF),[11] Renewable Northwest, and parties representing the Coalition for Community Solar Access (CCSA).[12] Stakeholders encouraged the Commission to act immediately to begin consideration of an alternate bill credit rate for two reasons:

1. Timing: Third-party developers need to know what the rate will be so that they can decide whether to participate in the Oregon market. Establishing an alternate rate may be time consuming and waiting until April to start the decision making process will not provide sufficient time for developers to perform their market analysis and access the full 30-percent Federal Business Investment Tax Credit (ITC) if they choose to participate.
2. Value: Stakeholders argued that the draft RVOS may be too low to support a successful program. Third-party developers may not be able to secure financing without a more favorable economic proposition to customers. Some stakeholders cited the need to incentivize participation through the bill credit rate specifically. Concerns specific to the viability of low-income focused projects were also raised.

In response, the Commission ordered that a Commission Workshop on the alternate bill credit rate be held prior to April 2018.[13] This report is intended to support discussion of an alternate bill credit rate at the Commission Workshop.

In this report, Staff provides context for the consideration of an alternate rate by discussing three fundamental questions:

1. What are the legal considerations for the Commission to adopt an alternate rate?
2. How should the Commission determine if an alternate rate is needed?
3. How should the Commission establish an alternate rate, if it's needed?

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[8] The sub-group report is available in Appendix E of Order No. 18-042.
[9] Order 18-042, pp. 14 – 16.
[10] *Ibid*, p. 15.
[11] Written comments submitted by Bonneville Environmental Foundation on January 29, 2018. http://edocs.puc.state.or.us/efdocs/HAC/um1930hac16932.pdf
[12] Remarks made at the January 30, 2018 Regular Public Meeting, beginning at minute 70.
[13] Order 18-042.

Legal Considerations Regarding an Alternate Rate
SB 1547 Section 22(6)(b) authorizes the Commission to adopt a bill credit rate other than one that reflects RVOS if the Commission has "good cause". This section discusses two legal considerations: first, the establishment of good cause; second, the legal authority to adopt an incentivized rate i.e., establishing a bill credit rate above the value of the solar to incentivize participation.

Good cause
The Oregon Supreme Court has clarified that the determination of "good cause" is not a subjective determination. Good cause is a legally sufficient ground or reason that depends upon the circumstances of the individual case:

> "We acknowledge the temptation to treat indefinite terms like "good cause" [or] "sufficient reason" * * * as calling for a subjective determination and thus, as invoking personal judgment. However, it is clear that, when such terms appears in a statutory context, they are focused on real, albeit sometimes difficult to discern, legal standards: the legislature's view of what is "good" [or] "sufficient[,]" * * * . In no case would judicial discretion play any role in the "good cause determination * * * [.][14]

With respect to the "good cause" standard in the administrative law context, the Oregon Supreme Court has specified that the phrase 'good cause' is a delegative term that calls for the agency to complete a value judgment that the legislature itself has only indicated. [15] On review, a court will review the agency's application of a delegative term to determine whether the agency's action was within the scope of authority conferred by statute. [16]

To determine what may be good cause to adopt a different bill credit rate, the Commission should examine the text of SB 1547 to discern the legislature's view of what is good cause. Provisions of the statute that may be pertinent to this inquiry include (but are not necessarily limited to SB 1547 subsections 22(1)(a) and (2)(b). In section 22(1)(a), the legislature specified that a community solar project is intended to provide owners and subscribers the opportunity to share the costs and benefits associated with the generation of electricity by solar photovoltaic energy systems.

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[14] *State v. Johnson*, 339 Or. 69, 85-87, 116 P.3d 869 (2005) (Discussing "good cause" requirement under *former* 1964 Criminal Code § 320).
[15] *Lombardo v. Warner*, 340 Or. 264, 270-72, 132 P.3d 22 (2006).
[16] *Id.*

In subsection 22(2)(a), the legislature directed the Commission adopt rules to establish the Community Solar Program and in subsection 22(2)(b) specified that the rules shall, at a minimum:

- Incentivize consumers of electricity to be owners or subscribers;
- Minimize the shifting of costs from the program to ratepayers who do not own or subscribe to the community solar project;
- Where an electric company is the project manager, protects owners and subscribers from undue financial hardship; and
- Protect the public interest.

Staff finds that establishing good cause could rest on the Commissioners' determination that an alternate rate is required to accomplish the above objectives. Staff notes that objectives may offer discordant direction such as incentivizing participation and minimizing cost shift. Staff's report attempts to explore these complex issues in support of the Commission's efforts to explore tradeoffs and solutions.

Incentivization
Additional consideration of the legislative directive to incentivize participation is required in regard to Stakeholders' suggestion this be accomplished through the bill credit rate. If the Commission adopts a bill credit rate that is higher than a rate that reflects RVOS, the Commission may not have authority to require ratepayers that do not participate in the CSP to pay costs associated with the increment above RVOS. This is because the Commission does not appear to have general authority to require ratepayers to bear costs of solar generation from the Community Solar programs if the alternate rate is higher than RVOS.

The legislature has specifically given the Commission authority to require rate recovery for externalities in certain circumstances. For example, in 2009, the legislature expressly authorized the Commission to allow utilities to recover through retail rates the costs of incentive rates paid to participants in a volumetric pilot program adopted to test the effectiveness of such rates in incentivizing solar development.[17]

Considerations to establish good cause for an alternate rate would appear to compete with a lack of general authority to require all ratepayers to bear the costs of an alternate rate that is above the RVOS. Due to this complexity, Staff finds it is paramount for the Commission to make a determination on this threshold issue of general authority in connection with any decision on what is good cause for an alternate rate.

[17] ORS 757.365.

Framework to determine if an alternate rate is needed
Stakeholders have raised two grounds for an alternate rate to be established: timing and value. To date, Staff has framed the question of an alternate rate in the context of timing, specifically in terms of establishing an interim rate, i.e., whether an alternate rate is required until the RVOS is available. To address timing issues, Staff examines when the RVOS will be available. Then, Staff compares the RVOS timeline to timing considerations for program launch.

RVOS Timing
In January 2015, the Commission opened Docket No. UM 1716 to develop methodologies that are transparent, predictable, and lead to the development of standardized calculations of the resource value of solar.[18] The Commission outlined a two-phase process, "The first phase will examine elements and methodologies. The second phase will examine values for each utility using those adopted methodologies."[19] Phase 1 concluded on September 15, 2017 with the adoption of eleven RVOS elements.[20] Phase 2 began with individual utility submissions of initial, utility specific calculations in November and December, 2017.[21] As of the date of this report, parties have submitted comments on the utilities' initial values and are developing opening testimony. The table below illustrates the remaining procedural milestones for Commission decision on the utilities' values, which culminate September 1, 2018.

UM 1716 Procedural Milestone	Date
Staff/Intervenor Opening Testimony	March 16, 2018
Commissioner Workshop	April 5, 2018
Utilities Reply/All-Party Reply	April 20, 2018
All-parties Cross-Exam Statements	May 7, 2018
Hearing on RVOS Filings	May 21, 2018
All Parties Opening Briefs	June 11, 2018
All Parties Closing Briefs	July 2, 2018
Target Date for Decision	September 1, 2018

[18] The Commission opened UM 1716 to determine the resource value of solar and the extent of cost-shifting, if any, from net metering, and to evaluating the reliability and operational impacts of increasing levels of solar generation. The Commission has since closed its evaluation of the reliability and operational impacts of solar generation (Order No. 16-074) and has put the examination into cost-shifting on hold pending a Commission determination of RVOS for each utility. UM 1716 efforts are focused on establishing the resource value of solar.
[19] Order 15-296, p. 2.
[20] Order 17-357.
[21] See dockets UM 1910, UM 1911, and UM 1912.

Stakeholders continue to advance through the process to determine an RVOS. The initial rates provided by the utilities are indicative but the final values may be set higher based on Stakeholder input.

It is critical to note that additional time may be required to establish a CSP bill credit based on the RVOS. At a January 31, 2017 workshop, stakeholders began scoping the application of RVOS to the CSP bill credit rate. Stakeholders identified many issues that must be resolved before September if the RVOS rate is to be immediately applied as the CSP bill credit rate. Example: will the RVOS be established at the utility level or will it be more granular to the project type or location. With this in mind, Staff also notes that efforts to establish an alternate rate might slow or replace the effort to determine the exact process to apply RVOS to the CSP bill credit rate as soon as the Fall of 2018.

Investment Tax Credit Timeline
The primary timing consideration raised by Stakeholders is access to the full Investment Tax Credit (ITC).[22] The ITC rate for eligible solar projects is based on the year in which construction begins. Qualifying projects that begin construction by the end of 2019 receive a tax credit based on 30 percent of the cost to construct the facility. After 2019, the ITC steps down several times and continue at 10 percent after 2022.

Construction Begins	2018	2019	2020	2021	2022	Future Years
ITC Amount	30%	30%	26%	22%	10%	10%

To understand the interaction of the ITC step-down process and community solar project development, Staff engaged the Oregon Solar Energy Industries Association (OSEIA) to provide high-level development estimates.[23] Assuming that the earliest a potential community solar Project Manager could need the bill credit rate is the beginning of the project development process, the bill credit rate (or a general idea of the bill credit rate) must be known 16 – 21 months prior to beginning construction.[24] If the latest a potential community solar Project Manager could know the bill credit rate is when a project's rate is assigned at pre-certification, the bill credit rate must be known 9 – 11 months prior to construction. Based on these assumptions, the bill credit rate must be established between March 2018 and August 2018 to secure the full 30 percent ITC.

[22] 26 U.S. Code § 48(a)(6)(A)(i).
[23] OSEIA's complete estimated timeline is available in Appendix A.
[24] OSEIA estimates that projects will take 7 – 10 months to complete the requirements of pre-certification, 3 – 5 months to acquire customers, and 6 months to engineer, procure, and construct the project after receiving final certification.

In addition, informal stakeholder discussion indicates that the utility interconnection process may take 6-18 months and can take as long as 24 months. At the time of this report (February 2018) projects that have not initiated the interconnection process are could miss the deadline secure the 30 percent ITC, regardless of the RVOS process.

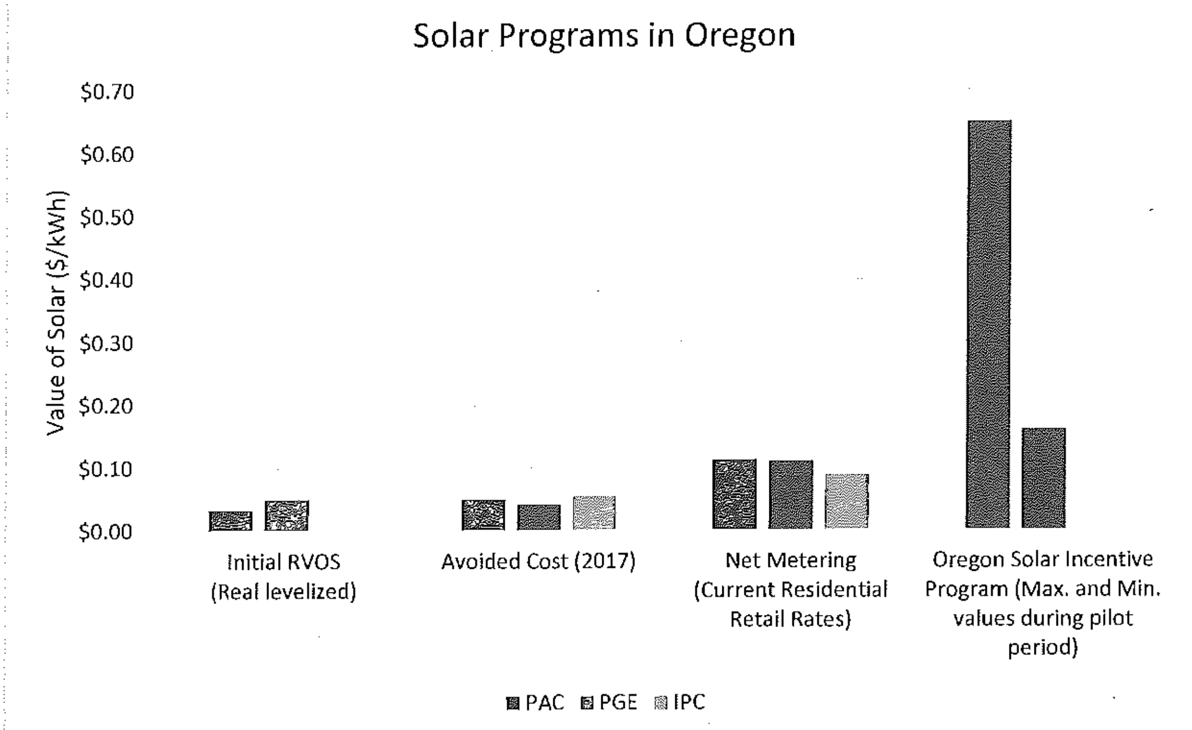
Further Timing Considerations

Staff's analysis suggests it is possible that the establishment and adoption of RVOS as the CSP bill credit rate – let alone the development and adoption of an alternate rate – will not be finalized in time for solar projects to access the full ITC. However, Staff is unclear the extent to which that this will materially impact program launch or program success. Staff reached this conclusion for the following reasons:

- Initial utility RVOS values already provide prospective community solar Project Managers with a general sense of the minimum RVOS rate. At this time, prospective Project Managers would benefit from an indication of whether the Commission plans to adopt an alternate rate due to the current RVOS value. However, Staff feels a floor may have been set for prospective Project Managers to evaluate participation in the Oregon CSP.
- It is not clear whether a 26 percent ITC rate as opposed to a 30 percent ITC rate results in a material impacts to project construction for the CSP.
- It is not clear that establishing an alternate rate will be faster than finalizing the RVOS and applying it to the CSP, particularly if Stakeholders continue efforts to resolve issues related to application of RVOS to CSP.
- Elements such as the establishment of a Program Administrator and the interconnection process may play a larger role in dictating program launch than finalizing of RVOS.

Staff finds that consideration of an alternate CSP bill credit rate may benefit more from focus on the value of the RVOS than on the timing of RVOS.

RVOS Value



Company	Initial RVOS values Real levelized ($/kWh)
PacifiCorp	$0.03284[25]
Portland Generation Electric	$0.04988[26]
Idaho Power	$0.00161[27]

- **Avoided Cost:** In 1978, the Federal Public Utility Regulatory Policies Act (PURPA) introduced a framework to value renewable energy from third-party renewable energy producers. Under PURPA, electric companies are required to "purchase power from [Qualifying Facilities] at rates that are just and reasonable to the utility's customers, in the public interest, and that do not discriminate against QFs, but that are not more than avoided costs."[28]

  In Oregon, avoided cost rates are adopted by the Commission and represent the rate at which the electric company would have paid to acquire the energy absent

[25] PAC/100, MacNeil/3.
[26] PGE/100, Goodspeed/7.
[27] IPC/100, Haener/4.
[28] 16 U.S.C. § 824a-3(d).

the purchase from the QF. When an electric company is resource sufficient, avoided costs are based on weighted market prices. When the electric company is resource deficient, avoided costs are the fixed and variable costs of a proxy resource that could be avoided or deferred. Utilities update these rates every year and facilities receive the rate for 15 years.

Company	2017 Standard Avoided Cost Rate For Solar Project ($/kWh real levelized, 15 yr)[29]
PacifiCorp	$0.04985[30]
Portland General Electric	$0.04149[31]
Idaho Power	$0.05460[32]

- **Net Metering**: In 1999, House Bill 3219 authorized Oregon to adopt a net metering program, declaring that "net metering encourages private investment in renewable energy resources, stimulates in-state economic growth, enhances the continued diversification of this state's energy resources and reduces utility interconnection and administrative costs."[33] Pursuant to ORS 757.300, customers of electric companies that generate onsite renewable energy are charged for their net energy usage. To the extent the customer generates more electricity than they consume, the customer receives receive a kWh bill credit for excess generation to apply to a future bill. Because the customer is only charged for net usage, the value of solar generated is, by default, the volumetric retail rate.

  At the time net metering was established, the distributed renewables market was relatively young and crediting over-generation at the retail rate was the most practical available mechanism to value output from customer solar facilities. Further, crediting at the retail rate was intended, as an incentive rate to stimulate distributed solar development by improving economics of investment.

[29] Based on utility nonrenewable QF rates for 2017.
[30] Rate for a fixed-solar facility assuming real discount rate of 4.2%.https://www.pacificpower.net/content/dam/pacific_power/doc/About_Us/Rates_Regulation/Oregon/Approved_Tariffs/PURPA_Power_Source_Agreement/Standard_Avoided_Cost_Rates_Avoided_Cost_Purchases_From_Eligible_Qualifying_Facilities.pdf
[31] PGE's schedule 201 provides a single rate for solar facilities with real discount rate of 4.1%. https://www.portlandgeneral.com/-/media/public/business/power-choices-pricing/documents/business-sched-201.pdf?la=en
[32] Idaho Power does not offer a specific renewable energy QF rate for solar projects: http://www.puc.idaho.gov/electric/Idaho%20Power%20rates%2006-01-17.pdf , assumes real discount rate of 4.44%
[33] House Bill 3219, Whereas.

At the time net metering was established, the distributed renewables market was relatively young and crediting over-generation at the retail rate was the most practical available mechanism to value output from customer solar facilities. Further, crediting at the retail rate was intended, as an incentive rate to stimulate distributed solar development by improving economics of investment.

It is important to note that crediting at the retail rate relies on the generator directly offsetting onsite generation. CSP projects will connect directly to the utility system and will not offset onsite load. Further, Net Metering has been identified as a source of cost shifting. Concerns about cost shifting from Net Metering participants are one basis for Commission efforts to establish the RVOS.[33]

Company	Standard Residential Retail Rate ($/kWh)[34]
PacifiCorp	$0.1127[35]
Portland General Electric	$0.1103[36]
Idaho Power	$0.0880[37]

- **Oregon Solar Incentive Pilot**: In 2009, HB 3039 established a pilot program to test the feed-in tariff model, where distributed generators under 500 kW sold all generation directly to the utility at a volumetric incentive rate (VIR). Under the pilot program, participating customers sign a 15-year agreement with the electric company to receive the approved VIR for all power produced during that period. At the conclusion of the 15-year VIR contract, the customer-generator may continue to sell power to the utility at a rate determined by the resource value of solar.

  The charts below reflect the evolution of the VIR throughout the 2010 - 2015 pilot period. The Commission established the initial VIR for small- and medium-size systems based on the business model of the project developer or owner, asserting that, "A rate that does not allow the seller the opportunity to recover the cost of a project will not induce the needed investment in the facilities and might render the pilot program ineffective."[38] Thereafter, the VIR is adjusted based on program participation and the speed of uptake of the eligible capacity (known as

[33] *Investigation into the Effectiveness of Solar Programs in Oregon*, Public Utility Commission of Oregon, 2014, p. 2.
[34] Each electric company structures the standard residential rate differently. The rates presented reflect Staff's effort to capture the combined kWh rate for Distribution, Transmission, and Energy.
[35] Pacific Power, Schedule 4.
[36] Portland Generation Electric, Schedule 7.
[37] Idaho Power, Schedule 1.
[38] Order 10-198, p. 13.

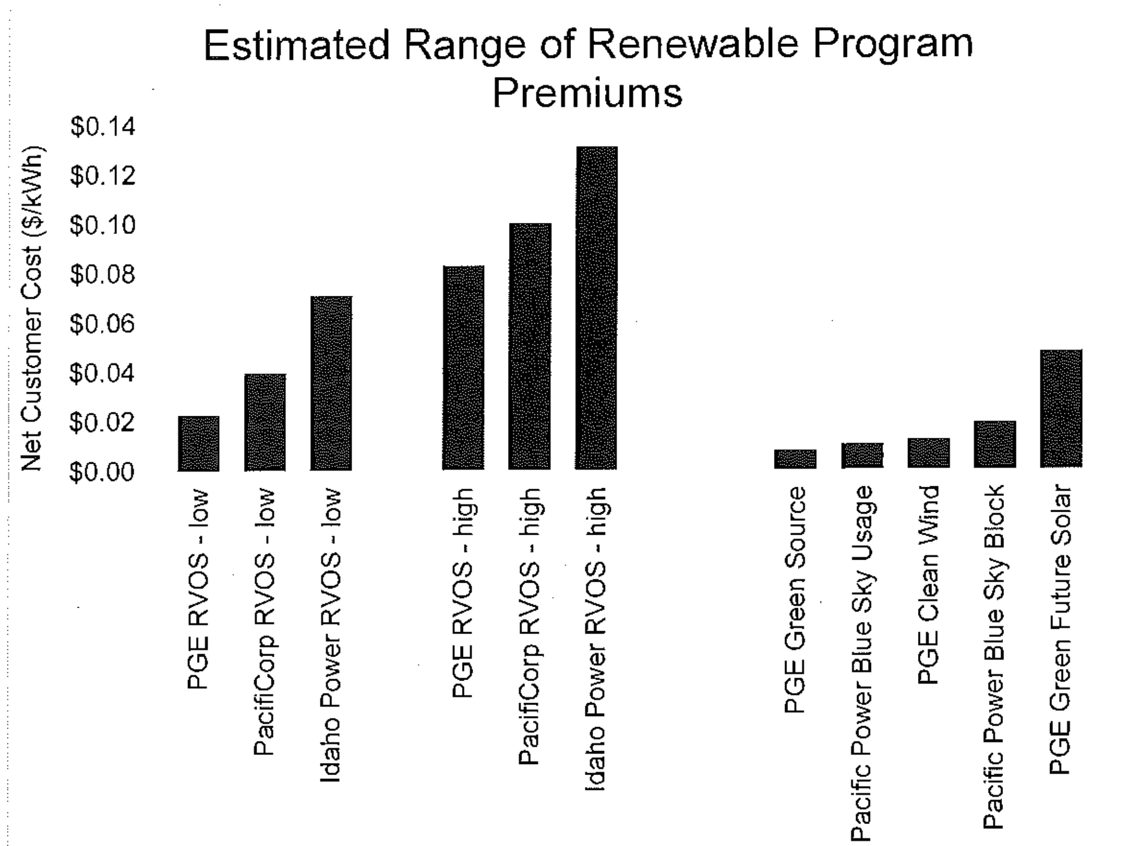
the "automatic rate adjustment mechanism" (ARAM))[39]. Since adoption, the VIR was adjusted down significantly, suggesting the mechanism to establish the VIR produced a value above what is required by the market. This was a primary driver for the Commission's efforts to establish the RVOS.[40]

History of Oregon VIR 2010 - 2015								
Geographic Region	**Zone 1**		**Zone 2**		**Zone 3**		**Zone 4**	
Project Size	**Small**	**Med**	**Small**	**Med**	**Small**	**Med**	**Small**	**Med**
2010	$0.65	$0.55	$0.60	$0.55	$0.6	$0.55	$0.55	$0.55
2011	$0.47	$0.40	$0.43	$0.40	$0.43	$0.40	$0.40	$0.40
2012	$0.41	$0.29	$0.35	$0.25	$0.35	$0.25	$0.32	$0.25
2013	$0.39	$0.23	$0.31	$0.18	$0.31	$0.18	$0.29	$0.18
2014	$0.39	$0.18	$0.25	$0.16	$0.25	$0.16	$0.23	$0.16
May-15	$0.35	$0.25	$0.23	$0.27	$0.23	$0.27	$0.21	$0.27
Aug-15	$0.32	$0.25	$0.23	$0.27	$0.23	$0.27	$0.21	$0.27

- **Voluntary Green Power Programs:** When considering the RVOS in relation to other solar program values, it is important to consider Oregon's voluntary green power programs. These programs provide context for Oregon consumers' high level of willingness to participate in renewable energy programs without a direct renewable generation value stream to the consumer. Portland General Electric and Pacific Power have the two largest voluntary green power programs in the nation in terms of participation and exceed 20 percent consumer participation in certain areas of the state. Participants in these program pay a premium that ranges from $0.008/kWh to a $0.05/kWh in addition to their regular bill. Despite the added costs, these programs have more than 270,000 participants combined.[41] It is important to note that these programs rely on the purchase of unbundled renewable energy certificates, rather than direct participation in a shared solar project. Therefore, these programs are more flexible than the CSP which requires a minimum ten year subscription term. On the other hand, the CSP may offer a more tangible, and therefore valuable, product option.

[39] Order 15-250, p. 4.
[40] *Investigation into the Effectiveness of Solar Programs in Oregon*, Public Utility Commission of Oregon, 2014, p.2.
[41] *Top Ten Utility Green Pricing Programs*, National Renewable Energy Laboratories, 2017. https://www.nrel.gov/analysis/assets/pdfs/utility-green-power-rankings.pdf.

To further understand Oregon consumers' willingness to participate in a premium renewable energy program, Staff estimated the economic proposition for CSP participants based on the RVOS. The table below provides a back of the envelop estimate that CSP participants might net a \$0.02 - \$0.13/kWh premium for participation. Due to time constraints and a lack of readily available industry data on Community Solar participation fees, these estimates are based on high-level, generic assumptions presented for use in this comparative exercise only. Specifically, the high to low range of participation fees assumes a 3 MW solar project, with a 20 percent Capacity Factor and a levelized cost of energy range of \$0.06 - \$0.08/kWh[42]. These estimates also assume a 10 percent profit margin for the Project Manager and a range of 10 - 30 percent overhead for customer acquisition and administration. This does not include a specific administrative fee for the Program Administrator of Low-Income facilitator



[42] Based on the LCOE for commercial solar provided in the National Renewable Energy Laboratories' 2017 Benchmarking Study, https://www.nrel.gov/docs/fy17osti/68925.pdf.

Company	Bill Credit Rate Based on Initial RVOS Real levelized	Estimated Participation Costs - low	Estimated Participation Costs - high	Estimated Participation Premium - Low	Estimated Participation Premium - High
All values presented in $/kWh					
PacifiCorp	$0.03284[43]	$0.06	$0.12	$0.03	$0.09
PGE	$0.04988[44]	$0.06	$0.12	$0.02	$0.07
Idaho Power	$0.00161[45]	$0.06	$0.12	$0.06	$0.12

In addition to examining other solar programs in Oregon, Staff surveyed the bill crediting mechanisms utilized by community solar programs in place in other states. This review is focused on programs in states with fully integrated retail markets, like Oregon. Staff included a sample residential retail rate to provide additional context for the relationship, or lack thereof in most states, between the retail rate and the bill credit rate.

[43] PAC/100, MacNeil/3.
[44] PGE/100, Goodspeed/7.
[45] IPC/100, Haener/4.

State/utility example	Residential Community Solar Bill Credit Rate ($/kWh)	Basis for establishing bill credit value	Average residential rate ($/kWh)
California - PG&E	$0.05428[46]	The Generation Credit is a credit equal to the average generation portion of the rate for the customer's class. Note: PG&E's community solar participation fee is $0.09838; however, there is a $0.015 admin fee and a $0.0291 charge to recover stranded generation costs. If you net those against the credit, it becomes $0.05428.	$0.23188[47]
Colorado - Xcel	$0.07325[48]	"Total Aggregate Retail Rate," minus the delivery fee (T&D)	$0.09585[49]
Minnesota - Xcel	• Pre 2017: $0.13331 - $0.16310 [50,51] • 2017 and beyond: $0.1033	• Projects in place before 2017 receive the Applicable Retail Rate[52] • In 2017 and beyond, projects receive that year's Value of Solar (VOS) rate which escalates ~2% per year over 25 years based on consumer price index.	$0.09032 - $0.10582

46 https://www.pge.com/pge_global/common/pdfs/solar-and-vehicles/options/solar/solar-choice/CommunitySolarChoicePlan_TermsConditions.pdf.

47 https://www.pge.com/tariffs/ResElecCurrent.xls.

48 https://www.xcelenergy.com/staticfiles/xe-responsive/Programs%20and%20Rebates/Residential/Solar-Rewards-Community-Service-Advice-Letter.pdf.

49 https://www.xcelenergy.com/staticfiles/xe-responsive/Company/Rates%20&%20Regulations/CO-rate-books-Electric-Summation-Sheet.pdf.

50 https://www.xcelenergy.com/staticfiles/xe-responsive/Working%20With%20Us/Renewable%20Developers/MN-SRC-Rate-Information-Sheet.pdf.

51 Projects that elect to sell their RECs to Xcel receive $0.15310 (> 250 kW) or $0.16310.

52 When the program first launched, the Minnesota Public Utility Commission (MPUC) defined the applicable retail rate to include the energy charge, demand charge, customer charge, and applicable riders for the appropriate class, which came in at approximately $0.12 per kWh. That rate was deemed "too low to reasonably allow for the creation and financing of community solar gardens. Rather, developers' uncontroverted statements indicate that a rate of approximately $0.15 per kWh is the conservative minimum needed to secure financing and make solar gardens attractive to subscribers." For that reason the MPUC decided projects could elect to sell their RECs to Xcel for $0.02 per kWh for solar gardens with a capacity greater than 250 kW and $0.03 for solar gardens with a capacity of 250 kW or less. The MPUC acknowledged that this adder does not reflect a market REC rate, but fills the gap that developers cited.
https://www.edockets.state.mn.us/EFiling/edockets/searchDocuments.do?method=showPoup&documentId={30B6A5B5-73CF-46E6-9E5D-B087352EA1AD}&documentTitle=20144-98041-01 pp 13 - 14

Additional considerations from other states:

- The state of New York developed a Value of DER (VDER) or "value stack" methodology for use in its community solar and other distributed generation programs. While this program operates in a state with retail choice, Staff finds it important to note its "Market Transition Credit" (MTC). The MTC is an adder applied only to community solar projects to make the VDER equal to the retail rate. As pre-determined capacity tranches are reached, the MTC will step down to 95% of the retail rate then 90 percent of the retail rate.
- New York's V DER and Minnesota's Value of Solar (VOS) include the value of environmental externalities. Oregon's RVOS does not include these values.
- The Minnesota Public Utility Commission (MPUC) conducted a process to similar to that underway in Oregon determine the appropriate bill credit rate for community solar. The program legislation prescribed a bill credit rate at the value of solar, but allowed for an interim rate if needed. In 2017, the MPUC ruled that all projects moving forward will utilize the VOS rather than the applicable retail rate. Also, beginning in 2018, Xcel will use location-specific avoided costs in calculating the avoided distribution capacity component of a project's rate. Finally, the MPUC is currently determining whether to include incentive "adders" that increase a particular project's credit rate based on specified attributes. The adders under consideration generally fall under locational factors and subscriber type.
    - Brownfield sites or landfills
    - Public facilities
    - Commercial or industrial rooftops
    - Prime agricultural land
    - Located in the communities the solar gardens serve
    - Residential subscribers
    - Low-income residential subscribers
- The State of Washington's community solar legislation does not dictate a bill credit rate, but establishes a $/kWh production incentive for qualifying community solar projects that steps down based on the year the project is certified.[53] The incentive is not paid by ratepayers, but by taxpayers. An additional $/kWh adder is provided for the use of Washington-made equipment.

[53] Washington ESSB 5939 Section 6.12.

Overall, Staff found that other states base the bill credit rate on one of two values:

1. A value of solar, or
2. A version of the retail rate, with state-by-state variation in the specific application either methodology i.e., Colorado does not include transmission and distribution charges in their application of the retail rate to community solar.

In addition, Staff found that different manifestations of an adder were deployed or under consideration in the several states (Minnesota, New York, Washington) but not all (California, Colorado).

As with other solar programs in Oregon, initial RVOS values are relatively lower than community solar bill credit rates established for similar state programs.

The California program example is the closest value to RVOS out of the states reviewed. California utility programs enrolled customers in 22 MW as of June 2017, but no third-party project development occurred as of that date.[54]

By contrast, Oregon's initial RVOS values are most significantly different from the Minnesota program example. In Minnesota's program, only third-party project development is permitted with the exception of low-income focused projects. As of February 14, 2018, 72 projects were online with a total capacity of 271 MW.[55]

In summary, the survey of solar program rates in Oregon and community solar bill credit rate in similar state programs indicate that initial RVOS values are lower than values in all other programs. However, Staff notes that solar development is occurring at all values and concludes that it is not conclusive that these values are too low to facilitate participation. Further, data from voluntary green power programs suggest that there is potential consumer demand for renewable energy products regardless of a direct renewable generation value stream to the consumer.

Frameworks to establish an alternate rate

The framework presented below weighs potential program objectives derived from SB 1547.

Opportunity

SB 1547 states that a community solar project provides participants "the opportunity to share the costs and benefits associated with the generation of electricity by the solar

[54] See "Program Status" at http://www.cpuc.ca.gov/General.aspx?id=12181.

[55] Monthly Update Community Solar Gardens Docket No. E002/M-13-867, Xcel Energy, February 2018.

photovoltaic energy systems."[56] If opportunity is the central objective of the program, Staff envisions three potential considerations:

- If the objective of the program is make the program *available* to customers, the bill credit rate can be set at any value. The Commission may endeavor to make the program available as soon as possible by adopting a rate that is already established, such as the avoided cost rate, retail rate, or current iteration of RVOS, as a transitional or permanent CSP bill credit rate.
- If the objective of the program is to make community solar *accessible* to any customer, the credit rate should reflect a no cost economic proposition such that any customer can access the program, regardless of economic status. In this event, the approach should be incentive-driven, and, at minimum, can be based on the anticipated credit rate required to break even. This is similar to the approach utilized by the VIR. Further, accessibility can target customer groups with the greatest barrier to access, such as residential or low-income customers. Under this objective the approach may consider additional adders such as those under consideration in Minnesota.
- If the objective of the program is to provide CSP participants with an *identical opportunity* to the current net metering program, the Commission could adopt the retail rate approach. This may consider the Colorado approach to adjust the retail rate for differences in transmission and distribution value between onsite generation and community solar projects. In addition, this approach warrants a caveat that, at some point, RVOS may be considered as a replacement to the current net metering retail rate approach.

Fairness

SB 1547 directs the Commission to establish a program that minimizes cost shifting to non-participants.[57] It is expected that ratepayers will bear the cost of crediting CSP participants for their portion of a projects' generation. The table below shows the potential magnitude of ratepayer costs associated with various approaches to valuing solar generation. This table is provided solely for illustrative purposes and represents a back of the envelop calculation based on high-level assumptions and using a single electric company as an example. If fairness is defined as minimizing cost-shifting, the Commission should adopt an approach that reflects the value of the solar projects' energy to the system and ratepayers. In Staff's example, the potential difference in ratepayer costs between the existing RVOS and the volumetric retail rate could exceed $300 million over 20 years. Staff does not find this to be a negligible amount.

[56] SB 1547 Section 22 (1)(a).
[57] SB 1547 Section 22 (2)(b)(B).

Approach	PGE value ($/kWh real levelized)	Estimated ratepayer cost to purchase output over 20 years[59]
RVOS	$0.04988	$279,647,232
QF avoided cost	$0.04150	$$232,609,536
Minnesota VOS	$0.10330	$579,141,120
Retail rate	$0.11030	$618,385,920

While the CSP bill credit rate is locked in for the duration of the contract between the Project Manager and the electric company, the use of an automatic rate adjustment mechanism (ARAM) as used in the VIR could minimize cost shift, as well.

Participation
As mentioned previously, SB 1547 directs the Commission to establish a program that incentivizes participation. Staff notes that the legislation does not specify that incentivization must be financial and that its market analysis is not sufficient to conclude with certainty that the RVOS credit rate will not incentivize participation.[60] However, reflection on the differences in Minnesota and California program size indicate that higher credit rates are very likely to support higher consumer demand. If the central objective is to financially incentivize participation, the Commission should select an approach that likely reflects bill savings, such as the retail rate or and/or an incentive-driven rate designed specifically to produce bill savings.

Project development
Another potential objective for the CSP is driving the development of additional solar projects in Oregon. While this is not a stated objective in the legislation, it is a recurrent consideration proposed by certain Stakeholders. If the goal of the program is to develop as many projects as possible, the Commission should adopt an approach that focuses on de-risking and maximizing the business case for developers. This approach may reflect Minnesota pre-2017 Applicable Retail Rate adders or the VIR AARM.

In addition, the Commission may consider market development and transformation through the use of transitional credits that diminish over time, similar to New York's MTC.

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[59] Assumes 160 MW is fully subscribed for 20 years and generates ~ 5,606,400,000 kWh over 20 years.
[60] Over 200,000 Oregon customers appear to be willing to pay a premium to support renewable energy development in the region. The average participation level would have to be as low as approximately800 watts to exceed that number of customers to fully subscribe the first capacity tier.

Project ownership diversity
Staff also finds it valuable to mention project diversity in addition to project development. If a mix of utility and third-party projects is a priority, the Commission should adopt an approach similar to that recommended for project development. Community solar is not an electric company's primary business model. While electric companies may have a lower cost of capital, lower margins, and lower overall risk, third-party developers have a lower threshold for subscription risk and may not participate if the customer economic proposition is deemed insufficient.

Additional factors to consider
Finally, Staff's examination of different approaches to identifying a solar value has produced a series of additional considerations for the Commission in contemplating an alternate bill credit rate:

- What is the role of "adders" and how would they be identified?
- Will the rate be fixed or escalate?
- Will the alternate rate approach be transitional or permanent? How should that glide path be established?
- If ratepayers bear the cost for program start-up, does the bill credit rate need to protect from loss of ratepayer investment?
- How long will it take to establish an alternate rate? There are many, potentially competing, considerations to establish an alternative rate, which may require significant time to conduct further legal analysis and gather stakeholder input.

Conclusion

Staff performed a survey of relevant market conditions to provide context and support for the Commission Workshop on the alternate bill credit. This analysis was grounded in three fundamental questions:

1. What is the legal authority for the Commission to adopt an alternate rate?
2. How should the Commission determine if an alternate rate is needed?
3. How should the Commission establish an alternate rate, if it's needed?

Timing considerations for RVOS may be less significant than discussion of the RVOS value, which was lower than the other values examined. Staff found that a wide range of approaches to establishing a value for solar generation exist and each can be applied to meet different program objectives. Consideration of an alternate bill credit rate based on its value is legally complex and requires reflection on the objectives of the program.

PROPOSED COMMISSION MOTION:

Staff provides this informational report to support discussion of an alternate bill credit rate for Oregon's Community Solar program. It does not provide a specific recommendation at this time.

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Appendix A: Community Solar Program Example Timeline

Time to complete task	3MW project timeline assumptions		1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27
1-4 months	Land control																												
6-18 months	Interconnection																												
3-6 months	System Impact Study (part of interconnection)																												
9-18 months	Utility system upgrades (from utility)																												
4-10 months	Non-ministerial Permits																												
2-3 months	Ministerial Building Permits																												
7-10 months	Community Solar pre-certification																												
3-5 months	Subscriber acquisition																												
2-3 months	Engineering & Design																												
1-2 months	Utility PPA																												
2-4 months	Finance (includes running pro forma prior to start)	✓pro forma				✓pro forma						✓pro forma						✓pro forma											
1 month	Procurement																												
2-4 months	Construction																												
1 month	Community Solar final certification																												
	Timeline to Full ITC - starting construction in 2019	**12/17**	**1/18**	**2/18**	**3/18**	**4/18**	**5/18**	**6/18**	**7/18**	**8/18**	**9/18**	**10/18**	**11/18**	**12/18**	**1/19**	**2/19**	**3/19**	**4/19**	**5/19**	**6/19**	**7/19**	**8/19**	**9/19**	**10/19**	**11/19**	**12/19**	**1/20**	**2/20**	**3/20**
	Major Milestones					M1					M2	M3		M4			M5	M6				M7		M8			M9	M10	
						Site Control					System Impact Study complete	CS Pre-Certification complete		Non-ministerial permits complete			Subscriber acquisition complete	Interconnection complete . Agreement signed				Building permits complete		Start Construction			Construction Complete	CS final Certification Complete	