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Joint Comments on Behalf of the Oregon Solar Energy Industries Association and Coalition for Community Solar Access in UM 1930
March 1, 2018

The following joint comments are provided by the Oregon Solar Energy Industries Association (OSEIA) and Coalition for Community Solar Access (CCSA), hereafter referred to as "Solar Parties." We appreciate the opportunity to provide this feedback on the credit rate associated with Oregon's community solar program, under Docket # UM 1930.

OSEIA is a trade association founded in 1981 to promote clean, renewable solar technologies. OSEIA's mission is to make solar energy a significant energy source by expanding markets, strengthening the industry, and educating Oregonians about the benefits of solar energy.

CCSA is a national business-led trade organization that works to expand access to clean, local affordable energy nationwide through community solar. CCSA's mission is to empower energy consumers, including renters, homeowners, and households of all socio-economic levels, by increasing their access to affordable, reliable clean energy.

Our combined national and local perspectives represent a comprehensive understanding of both the drivers and challenges of community solar policies. We have a vested interest to ensure community solar will work in Oregon.

1 Overview

The Solar Parties appreciate and applaud the PUC and Staff in their commitment to getting us to where we are today, including the support of ongoing implementation efforts associated with the various subgroups. The PUC and Staff have rightly recognized the need and urgency to address arguably the most critical component of the program: the credit rate. The Solar Parties also appreciate the Staff's "informational filing" released on February 26 (Staff Report). The Report provides a useful overview and data points for consideration by the PUC in setting a direction for the credit rate, though we do provide a rebuttal to several of their points throughout these comments. The following comments attempt to articulate exactly why the Solar Parties view the credit rate as the most critical aspect of the program while also providing recommendations on how it could be designed to help ensure a successful program is operating before the end of 2018. These comments are organized into three primary sections, including:

- **The Case for "Good Cause"**- The authorizing legislation and PUC rules provide the PUC with the discretion and tools necessary to establish a credit rate other than the Resource Value of Solar (RVOS). The justification for this "good cause" falls into three main categories: timing; value; and program viability.
- **Credit Rate Valuation Considerations** – Community solar has evolved into a robust segment of the solar industry with a wealth of national experience that can inform Oregon's credit rate design. There are also important considerations relating to credit rate valuation and project economics more generally that need to be considered, such as: financing demands of mid-scale solar development; customer acquisition and ongoing customer service costs; project location; administrative costs; and numerous other state and Federal benefits and burdens that can impact development costs.
- **Recommendations** – The industry and stakeholders are largely aligned with the need to establish a credit rate by April to support a program rollout by the end of 2018. In light of the timing and valuation concerns highlighted throughout these comments, we recommend deferring to experience demonstrated from other markets as well as within Oregon's existing solar programs and to leverage the retail rate or fixed rate based on the retail rate as the "initial program capacity tier's" credit rate. With that secured, the PUC, Staff, Program Administrator and stakeholders can re-focus on remaining critical implementation needs in parallel to investigating the role RVOS will play in the program.

2 The Case for "Good Cause"

While SB 1547 called for the use of a credit rate that "reflects the resource value of solar", it also provided the PUC with clear discretion to adopt a "different rate" if it – the PUC - found "good cause."[1] The PUC acknowledges this authority in Order No. 17-232, whereby it suggests an "interim" rate could be considered if there appeared to be a conflict in timing between the program launch and finalization of Docket No. UM 1716 (re: RVOS). In the actual adopted rule, the PUC leaves this discretion more open by simply stating that they may establish a different rate – not based on the RVOS - through "Commission Order."[2] Given the lack of parameters in the legislation (SB 1547) on what would merit "good cause" to use a different rate, and the authority given to the PUC in this regard, the Solar Parties submit three key factors to guide the PUC's decision:

1. **Timing:** Due to the extended timeline associated with implementation of both the RVOS and the community solar program, relying on the RVOS to set the bill credit rate would result in an unacceptable delay in the launch of the community solar program.
2. **Value:** The RVOS structurally undervalues the contributions of community solar projects and is too low to drive investment.

[1] SB 1547. Sec. 22.(6)(a) and Sec. 22.(6)(b)

[2] Order No. 17-232. 860-088-0170(1)(a)

3. **Viability**: If the community solar program launches with a bill credit value that is too low to support project development, the program will fail in its objectives of expanding access to solar and yielding benefits for customers.

At present, the program is at risk of failing to drive any project development or serve any customers, thwarting the statutory objectives of SB 1547 and the intention of the Legislature in creating the program in the first place. This risk constitutes good cause for the PUC to approve a bill credit rate.

2.1 Timing

In Order 17-232, the PUC indicates that a mismatch between the timing of the RVOS docket (UM 1716) and the timing of the community solar program launch could be grounds for establishing a rate that is not necessarily reflective of the RVOS. It tasks the Program Administrator and Staff with monitoring the status of these parallel processes and recommending action, if necessary.

The RVOS process (UM 1716) and associated target deadline was recently extended from July 2018 to September 1, 2018.[3] Further, the completion of UM 1716 will result in RVOS rates that aren't completely applicable to the community solar program. The RVOS was never initiated to directly apply to any specific identified program and there is no planned implementation phase of RVOS to do that transition into actual tariff design. The discussion during the Staff-led workshop on January 31st provided initial evidence that the UM 1716 RVOS methodology was not necessarily the same as the UM 1930 "community solar RVOS" credit. The RVOS is a standalone docket establishing the value of solar – it is not a process to establish the rate of a community solar program. The RVOS can be used to establish a community solar bill credit rate but the community solar specific elements should be additional factors added to or subtracted from RVOS as appropriate. The Staff Report also acknowledges the potential extra work required, stating (pg. 8): "It is critical to note that additional time may be required to establish a CSP bill credit based on the RVOS." This point is underscores the fact that regardless of time, the Commission will have to develop a method to establish the CSP bill credit rate. The Commission should start on this method now.

As of today, there remains other community solar program details that need to be determined in UM 1930, and while the Program Administrator is expected to help finalize many of these details a Request for Proposal (RFP) for that role has not yet been issued. Addressing the credit rate now will reduce the heavy burden still facing the program to select a Program Administrator and complete the Implementation Manual.

Stakeholders and Staff have been focused on a goal to have the program launch before the end of 2018; the expectation has been early Q4. The reasoning for this has evolved, but it's worth providing some historical context. The first step toward a state-level community solar program

[3] UM 1716. Ruling. February 14, 2018.

came with the passage of House Bill 2941 in 2015, which required the PUC to investigate community solar design attributes and ultimately provide recommendations back to the legislature (submitted October 26, 2015). The passage of Senate Bill 1547 in 2016 ensured a program would be created and by the summer of 2017 the PUC adopted rules to lay the framework for a robust program. Stakeholders ultimately embraced the rule making and implementation efforts and have been working diligently with Staff and the PUC to expedite those processes. Enabling further delays would be unfair to the customers, stakeholders, and policy makers that have envisioned this program for so many years.

Importantly, the industry and stakeholders have already been surveyed as to what the "drop-dead date" should be for establishing a credit rate for the program and the vast majority of responses focused on April of this year.[4] We know for certain that an RVOS will not be ready in April, much less an RVOS that is readily adaptable to the community solar program. There are multiple reasons why April was identified by the industry and stakeholders as a deadline for determining the credit rate. In addition to those already mentioned above, the Q4 2018 target launch likely represents the last viable opportunity to get projects enrolled in the pre-certification process in time to be certified and commence construction ahead of the Investment Tax Credit (ITC) step-down (from 30% to 26%) at the end of 2019.

The Staff Report poses the question of whether the ITC reduction will have a material impact on the program launch or program success (pg. 9). The Solar Parties highlight that this reduction – in the simplest terms, a revenue loss of 4% of the capital expenditure associated with the project - does indeed have a material impact on project development costs and financing assumptions. A lowered ITC means a potentially higher credit rate would be needed to make up the difference, and/or greater incentives to support the low-income component of the program. The 30% ITC represents major savings for developers, customers, and the program and State more generally. It behooves Oregon to leverage federal funds to the greatest extent possible to save internal resources.

OSEIA has developed a project development timeline (shared with Staff and in the Appendix of these comments) that illustrates the time crunch the industry is already facing in order to meet an end of 2019 construction commencement. The pre-certification process alone could take 6-10 months, with construction not beginning until 12 months from that point. If the industry had confidence in the credit rate – and general program economics – developers could begin more aggressive investment and advancement in the project development cycle to be better positioned for submitting applications as soon as or shortly following the program launch.

Finally, it's worth noting that although projects already in the interconnection queue will be eligible to participate, an opportunity should also be available for developers interested in developing their own projects to participate in the program. In other words, the program shouldn't force all developers to purchase projects from those currently holding positions in the interconnection queue just to make the time cutoff to secure the full ITC. There should be

[4] See the Subgroup report submitted by Renewable NW on January 2, 2018, under Do. No. AR 603.

adequate time for completely new projects to be developed and submitted into the interconnection queue, and ultimately the program pre-certification process and still be able to leverage the ITC. This will be a challenge even with a known credit rate in April, but could at least be possible.

2.2 Potential Inadequacy of RVOS Value

Without the ability to monetize RECs or any known availability of other incentives, the credit rate lies at the heart of the program's ability to "incentivize participation," as mandated by the enabling legislation.[5]

While we don't have the final UM 1716 RVOS rates to review today, the initial calculations submitted by utilities in November – ranging from around $0.045-0.052/kWh – if translated directly into a community solar credit rate, would be far too low to support a viable community solar market in Oregon.[6] The Staff Report notes that "solar development is occurring at all values and concludes that it is not conclusive that these values [initial RVOS calculations] are too low to facilitate participation." (pg. 18) It's unclear whether the Report is referencing all types of solar development (community or not) or only referring to the three market examples (CA; CO; and MN) provided in the Report. (pg. 16) A direct comparison to either would be misleading without additional context around (at least) project design and subscription requirements; available incentives; and gauging the level of program success. A more comprehensive table is provided in these comments (see Section 3.2 Credit Rate Examples) to help compare not only the credit rates for various programs but also shed light on some other key economic (and policy) considerations impacting program results. Regardless, the Solar Parties can assure the PUC and Staff that the initial RVOS filings are indeed too low to facilitate participation from third-party community solar developers in Oregon. These values would fail to provide sufficient cost recovery for projects that dedicate at least 50% of their capacity to residential and small commercial customers, much less produce savings for those customers.

As discussed in greater detail in Section 3 (Credit Rate Valuation Considerations), there are incremental costs associated with community solar that separate it from standalone commercial and industrial (C&I) solar systems or qualified facilities (QFs). For a community solar project, developers incur marketing and customer acquisition costs in addition to ongoing administrative and technical costs associated with continued customer engagement and maintenance in addition to the O&M responsibilities for the system itself. These costs are compounded by the number and type of customers required by Oregon's community solar program. Program design requirements associated with residential and small commercial participation are an important consideration when comparing project economics and community solar program credit rates and incentives.

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[5] SB 1547 (2016)

[6] PAC - http://edocs.puc.state.or.us/efdocs/HTB/um1910htb145759.pdf; ID Power - http://edocs.puc.state.or.us/efdocs/HAA/haa131832.pdf; PGE - http://edocs.puc.state.or.us/efdocs/HAA/haa163313.pdf

That said, community solar projects *are* similar to QFs and C&I systems in that they involve high upfront capital costs that are typically financed by a third-party entity and/or tax equity investor and therefore rely on a long-term revenue stream to secure that financing. Community solar adds an additional element in that the developer must establish numerous long-term contracts with subscribers as opposed to contracting a single power purchase agreement (PPA) with a utility or large off-taker. It's therefore on the developer to be able to confidently secure long-term (typically 20+ years) contracts with customers. Third-party community solar developers are unable to secure long-term contracts if there are not adequate savings to the participating customers. This is not a speculative concern: there are examples of community solar markets that are intended to enable third-party development but have failed to attract industry interest or development due to the economics driving a premium rather than savings for the customers (See Section 3.2.1 for a closer look at California's program).

While the ability to provide customer-savings dictates developer engagement in a market, it remains worth highlighting just some of the documented research – aside from actual program implementation discussed in the next section - demonstrating how important savings are for those community solar customers.

- The Interstate's Renewable Energy Council's (IREC) defines offering "tangible economic benefits" as one of Five Guiding Principles for Shared Renewable Energy Programs.[7]
- A survey conducted by Shelton Group and SEPA found that customer interest in solar is driven by potential financial benefits (65%), followed by environmental impact (38%) and energy control (34%).[8]
- A survey conducted by Fresh Energy in Minnesota found that customer "interest in participation drops rapidly beyond a 10-year payback period" when considering whether to pursue a community solar opportunity.[9]
- A DOE-funded study found that "across-the-board solar cost reductions and long-term cost stability of solar generation have many community solar customers come to expect long-term cost-savings."[10]
- A Portland State University survey found that "as bill savings move from high to low, the proportion of respondents willing to participate changes from ~70% (+/- 10% depending on the project) to roughly 10%." In addition, "most respondents were neutral about

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[7] IREC. Feb. 2017. Five Guiding Principles for Shared Renewable Energy Programs.

[8] https://sepapower.org/resource/what-the-community-solar-customer-wants/

[9] Hoffman, S. and High-Pippert, A. (2015) Attitudes and Preferences towards Community Solar Initiatives. https://www.edockets.state.mn.us/EFiling/edockets/searchDocuments.do?method=showPoup&documentId=%7B72FBDBF8-27AD-402B-8827-7D5EFE43D302%7D&documentTitle=20153-107823-01

[10] Community Solar Value Project and U.S. DOE Sunshot. Community Solar Program-Development Landscape. A Brief for Utility Program Designers. Dec. 2016.

> project features, such as size or location. However, there was a stronger preference for projects emphasizing affordability, rather than location."[11]

The Staff Report states that the results of Oregon's green pricing programs suggest there is "potential consumer demand for renewable energy products regardless of a direct renewable generation value stream to the consumer" (pg. 18). Importantly, green pricing programs in Oregon (and elsewhere) do not provide an accurate comparison or benchmark for gauging the success or failure prospects of a competitive community solar market. For one, green pricing programs are an entirely different experience for customers compared to community solar. The Solar Parties are aware and supportive of the success associated with Oregon's green pricing programs to date[12], but we also note that it is a different solar experience and value proposition for customers and thus inherently serves a niche market – customers that are not price-sensitive and are focused on supporting the environment. Because it offers a direct connection and long-term commitment to a specific project, community solar is more akin to onsite rooftop solar and customer-centric programs such as net metering.

In addition, the revenues from these green-pricing programs are not used to finance the construction of tangible assets; the utilities are procuring energy from third parties and/or can utilize other sources of return to pay for any necessary assets. If a utility-run green pricing program is undersubscribed, the financial impact is low, as the utility can still generally recover the costs of the project and use the power to supply its general customer base. The lack of need for a guaranteed long-term revenue stream means that green tariff programs can offer flexible opt-in/opt-out opportunities for customers rather than requiring longer-term commitments. In contrast, community solar projects unequivocally use project-based financing. If the projects do not have a steady, reliable source of revenue, they cannot gain financing and will not be built. All experience the solar industry has in community solar markets nationwide, and with financiers from the largest to the smallest, shows that tangible economic savings for the customer must be present to allow for stable subscription and thus project financing.

A successful community solar program diversifies utility energy portfolios, provides customers with options and savings, creates jobs and economic development, and of course produces environmental benefits for the State. The legislature has provided the PUC with the direction to leverage community solar as a vehicle for achieving these important values, whether captured in the RVOS or not. Ensuring the program is able to successfully roll out and scale will help drive down costs as the market matures.

[11] Weaver, Anne. Portland State University. Renewable Energy & Community Solar Questionnaire. April 2017. Note, the study showed that of the 330 respondents (primarily liberal-leaning politically) to the survey, 60% were "somewhat or very interested" in joining a community solar project.

[12] NREL. Top Ten Utility Green Pricing Programs. 2016. https://www.nrel.gov/analysis/assets/pdfs/utility-green-power-rankings.pdf

2.3 Program Viability

The bottom line principle for determining whether there's "good cause" to use a rate other than the RVOS or in how to adjust the RVOS should be driven by a mission to make this a successful and functioning program. The arguments for "timing" and "value" obviously play into this underlying principle for the reasons articulated above. However, it's important to keep perspective on why the legislature created the program in the first place: not just to exist on paper, but to produce real projects serving customers.

The Solar Parties appreciate the Staff Report's articulation of the decisions that are before the PUC with regards to defining a successful outcome for the program. (pgs. 18-21) It references three primary excerpts from SB 1547 to help decipher the legislative intent for the program:

- To enable community solar projects to "provide owners and subscribers the opportunity to share the costs and benefits associated with the generation" from solar systems;
- To adopt rules that "incentivize consumers of electricity to be owners or subscribers; and,
- To adopt rules that minimize the shifting of costs from the program to ratepayers who do not own or subscribe to a community solar project."

The Solar Parties view the mandate as clear: make a community solar program that results in robust participation opportunities for consumers in a cost-effective manner. Establishing a community solar program does not, in itself, equate to incentivizing participation in that program. Incenting something is an action-oriented term with a goal of actually producing an outcome (customer participation), rather than simply making it available. Put another way, a community solar program that fails to draw participation would be failing to live up to the statute because it did not adequately incentivize consumers.

The Solar Parties recognize that attempting to minimize ratepayer impacts is an important goal for the community solar program, as it is for any program enabled by the PUC. We also do not object to identifying those costs in a transparent manner and continually working toward cost reductions as the program evolves, again, something that should be inherent in all types of programs. However, the legislation calls to "minimize" that cost shift rather than mandating there be "no" cost shift. The difference here is significant, as demonstrated in California where legislation *did* call for "no" cost shift and has resulted in a premium-based program with no third-party development (see Section. 3.2.1, California in Focus).

The Staff Report cites "fairness" as something that could be defined as minimizing cost-shifting, and provides estimates of incremental costs between various credit rates relative to the RVOS. The Solar Parties view this as an unreasonable comparison given: 1) the RVOS is at least six months away from final calculations; and 2) the RVOS was not developed for community solar and does not accurately capture all of its costs or benefits. Those benefits could fall into the eleven elements already included in the RVOS methodology as well as additional benefits such as creating savings for low-income customers and supporting economic development, among others.

We would also pose that fairness is one of the key attributes of community solar. The impetus for pushing on the establishment of a community solar program is rooted in a demand to provide a more equitable opportunity for all types of customers to participate in both the costs and benefits of solar generation. The U.S. Department of Energy estimates that about 50% of households and businesses are unable to host a PV system due to property constraints[13], and GTM Research estimates that 77% of U.S. households are locked out of the onsite rooftop market when accounting for policy and financial considerations.[14] Oregon has provided homeowners and businesses with an opportunity to net meter onsite (typically rooftop) solar systems for nearly 20 years. In fact, the State has gone a step further to enable more customers with suitable property to pursue onsite solar by making available a residential energy tax credit (RETC) to all the state's residents and a solar installation rebate to homeowners and businesses in PGE and Pacific Power territories.

Eligible customers have responded to this opportunity and ETO estimates there are well over 100 MW-ac of onsite (rooftop) capacity installed (or about to be installed) in the state.[15] As the Staff Report notes, net metering was established in the state nearly twenty years ago to "encourage private investment in renewable energy resources, stimulate in-state economic growth, enhance the continued diversification of the state's energy resources and reduce utility interconnection and administrative costs" (pg. 11). The state has furthered support in this area through state-level tax incentives and utility rebates. However, the majority of Oregonians have not had an opportunity to leverage these programs or participate in the costs and benefits of solar. The passage of SB 1547 is intended to correct that market imbalance. Again, the law states that the program should "incentivize consumers of electricity to be owners and subscribers" of community solar projects. This is a clear directive to not only establish a program, but to ensure that it works well enough to result in a robust market similar to that provided to customers eligible for rooftop solar.

Lastly, the PUC states that part of the intent of establishing the initial program capacity tier size of 160 MW (2.5% of the IOU peak loads) was that it be "large enough to sustain the initial administrative costs" of the program.[16] Aside from failing to create solar participation opportunities for more customers, the planned cost recovery for the Program Administrator and related functions could be undermined if the program fails to drive project development. This should be another consideration with regards to the cost-effectiveness of ratepayer funds:

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[13] U.S. Department of Energy & National Renewable Energy Laboratory. (2015) Shared Solar: Current Landscape, Market Potential and Impact of Federal Securities Regulation.

[14] GTM Research. U.S. Community Solar Outlook 2015-2020. Summary can be viewed in this article: http://www.utilitydive.com/news/note-to-utilities-heres-why-2015-is-the-tipping-point-for-communitysol/403284/

[15] OSEIA Member Meeting. ETO presentation.

[16] Oregon. PUC. Order 17-232. Pgs. 7-8.

i.e., investing in something that provides those same ratepayers with a functioning and successful program.

3 Credit Rate Valuation Considerations

Community solar has evolved into a prominent segment of the solar industry, providing examples throughout the country of both successes and failures in program design. And while there are many variables that drive the direction of a community solar program, economics is typically the most important underlying factor. The credit rate is at the center of the economic equation, though programs often have additional incentives such as RECs. This section provides an analysis of the incremental costs associated with community solar projects; a summary of credit rates and other economic factors in several notable markets throughout the country; and finally, a list of key considerations that may influence the economic equation for community solar in Oregon.

3.1 Community Solar Costs

There are clear economies of scale and other cost efficiencies and advantages associated with providing access to solar to numerous customers through community solar projects, however there are also complexities and increased costs relative to similarly sized projects serving only one off-taker. In addition to customer savings, other financial modeling assumptions need to account for a project that is serving potentially hundreds of customers.

In general, community solar administrative costs include a combination of upfront (one-time) marketing and customer acquisition costs, in addition to ongoing (year-over-year) costs to account for customer replacement and customer management and billing costs. It's difficult to land on a firm value for these costs given the range of project sizes and diverse sophistication levels of the respective project managers. These costs are also impacted by the number and profile of subscribing customers. The inclusion of residential and small commercial customers in a project does add costs, though the Solar Parties are supportive of Oregon's policy to reserve capacity for those customers. The inclusion of residential and small commercial customers is a critical component of a successful community solar program, and if not required or sufficiently incentivized through policy, will be an overlooked market segment by the industry. Table 2 below (in Section 3.2) summarizing different markets helps illustrate that fact and includes a column on whether small customer participation is required in each market or not, as well as notes on the general outcome of each market's policy. Notably, the Staff Report fails to call out these types of details which are important in considering both the economics involved in community solar projects as well as the policy goals and objectives of a community solar program.

There are several public resources which provide reasonable benchmarks for determining a ball park for the incremental costs associated with community solar projects. A good starting point is to review an analysis by Sustainable Energy Advantage (SEA) in consultancy for the Rhode

Island Office of Energy Resources (OER) on cost assumptions for community solar in National Grid's Renewable Energy Growth (REG) program.[17] SEA surveyed the industry to ascertain the community solar administrative costs associated with projects that allocate at least 50% of their capacity to subscription sizes of 25 kW or less (i.e., residential and small commercial customers). They found that the upfront (one time) customer acquisition costs associated with these projects are about $0.25 per Watt (W)[18] and that the ongoing (annual) costs associated with customer replacement is $0.02/W/year, and the ongoing (annual) cost of customer management and billing is about $0.01/W/year.[19] Based on its survey of the industry, SEA highlights that educating, signing up, and retaining – including managing billing for – potentially hundreds of customers requires substantial effort, and that most developers hire 3rd-party lead generation and experience a conversion rate on prospects of 5%-10%.[20]

The Illinois Power Agency (IPA) recently adopted the assumptions from the Rhode Island analysis in developing REC pricing for their proposed Long-Term Renewable Resource Procurement Plan.[21] Specifically, the IPA created different "adder" REC values that would be provided to community solar projects with residential or small commercial customers accounting for at least 25%, 50%, or over 75%, of the project's capacity.[22] In developing the overall REC pricing for community solar, IPA's modeling assumptions also incorporated a 20% assumed customer savings based on the net metering credit value (i.e., discounting the credit rate at 80% of its actual value when calculating expected revenue for the project). IPA also assumed a slightly higher debt service coverage ratio compared to standard distributed generation projects.[23] Though not captured in the model, community solar projects with significant residential and small commercial customers also require a higher internal rate of return (IRR).

Massachusetts has also conducted an analysis to determine an incentive adder value for projects with at least 50% of capacity reserved for subscriptions under 25 kW in the state's Solar Massachusetts Renewable Target (SMART) program. The state requires compensation of

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[17] SEA. (2016) Rhode Island Renewable Energy Growth Program: 2017 2nd Draft Ceiling Price Recommendations. Found at: http://sos.ri.gov/documents/publicinfo/omdocs/minutes/6154/2016/49211.pdf.

[18] As a point of comparison, NREL finds customer acquisition costs for residential rooftop solar projects to be between $0.29-0.42/W. https://www.nrel.gov/docs/fy17osti/68925.pdf

[19] Note that the REG program uses a 20-year contract duration for community solar projects, and that legislation limits the premium paid for community solar to no more than 15% above the costs of a similarly sized non-community solar project

[20] This is a simple back of envelope calculation and does not assume a discount rate. Also note that these values are in direct current (DC).

[21] This Plan is currently under consideration with the Illinois Commerce Commission, and can be found along with associated appendices, here: https://www2.illinois.gov/sites/ipa/Pages/2018-Long-Term-Renewable-Appendices.aspx.

[22] See IPA's Filed Plan Appendix D (pgs. 13-16) and Appendix E-2 for details regarding the community solar pricing. https://www2.illinois.gov/sites/ipa/Pages/2018-Long-Term-Renewable-Appendices.aspx

[23] See IPA's CREST model assumptions for community solar (Appendix E-2) compared to standard distributed generation projects (Appendix E-1). https://www2.illinois.gov/sites/ipa/Pages/2018-Long-Term-Renewable-Appendices.aspx. Note that the Illinois community solar program is unique in that the base credit rate is the subscriber's energy supply rate only; and that projects are eligible for a $250/kW rebate.

an additional $0.05/kWh (for 20 years) above and beyond a base tariff rate of $0.155-$0.17/kWh.

Table 1 provides a comparison of the current or proposed levelized incremental pricing values (per kWh) for community solar projects in IL, MA, and RI. These values capture the incremental costs of a community solar project relative to an onsite solar project serving only one off-taker. Note that these programs have acknowledged the increased cost of including residential and small commercial customers in a project and adjusted the assumed incremental costs associated with those projects accordingly.

Table 1. Incremental Cost of Community Solar with Small Customer Participation (Levelized $/kWh)

Market	Project size	% Small Subscriber Participation	Incremental Rate ($/kWh)	Notes
Illinois	≤ 2 MW-ac	≥ 25 - 50%	$0.011[24]	REC is fixed over 15 years. Credit rates continue indefinitely, and are nearly 2x higher for resi./small comm.
		≥ 50 - 75%	$0.022[25]	
		≥ 75%	$0.033[26]	
Massachusetts	1-5 MW-ac	≥ 50	$0.050[27]	Fixed over 20 years
Rhode Island	< 1 MW-dc	≥ 50	$0.028[28]	Fixed over 20 years. Rates are legislatively capped to not exceed 15% above standard DG price.
	1-5 MW-dc	≥ 50	$0.024[29]	

3.2 Credit Rate Examples

In addition to examining the incremental costs associated with community solar projects in markets that have targeted the inclusion of residential and small commercial customers, it's useful to step back even further and review a broader sample of markets, their respective credit rates, and their known or expected performance. The following table compares a handful of programs, including examples of how several markets have evolved over time leveraging different credit rate structures and methodologies.

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[24] These rates are average across the two utility territory groups. See pg. 103. https://www2.illinois.gov/sites/ipa/Documents/2018ProcurementPlan/LTRRPP-Filed-Long-Term-Renewable-Resources-Procurement-Plan.pdf
[25] Ibid.
[26] Ibid.
[27] http://masmartsolar.com/
[28] http://www.seadvantage.com/Documents/Eyes_and_ears_Library/RI/4774-DGBoard-DR-PUC1-14-Exhibit2-1.pdf
[29] Ibid.

Table 2. Community Solar Market Examples

Market	Program / Utility	Credit Rate ($/kWh)	Credit Rate Methodology	Small subscriber participation	Notes	Does it work?
CA	GTSR ECR / PG&E	$0.05351[30]	A floating class average generation rate (i.e., energy supply rate) plus some other volumetric credits, offset by departing load charge and numerous other charges.	1/6th of project capacity within 60 days of PPA execution.	Low initial credit rate and high forecast uncertainty associated with future values are primary barrier to development	No – IOUs have not reported any successful contracts with developers.
CO	Solar Rewards (for projects awarded up through 2015) / Xcel	$0.07273[31] (Residential) ? – varies for C&I	Resi – floating retail rate minus some (not all) T&D charges. C&I eligible for customer-specific variable rate based on previous year's (kW+kWh) electricity costs minus some T&D	No requirement. Some residential participation (< 15% of subscribed capacity). Primarily C&I subscribed capacity[32]	Market partly driven by RECs (bidding process) and targeting C&I customers that have high customer-specific variable rates. 5% of projects go to low-income – generally treated as 5% loss in revenue.	~ 50 MW capacity was awarded and developed but residential sector underserved.
	Solar Rewards (for projects awarded 2016 or later) / Xcel	$0.07273[33] (Residential) ~$0.05-07 (C&I.)	Resi – same as above. C&I now also takes a fixed rate, and no longer eligible for variable rate. These rates float (likely escalate) over time.	No requirement. Likely little to no residential participation.	Bidding driven market toward fewest/largest C&I. Utilities responsible for low-income component (5% of program, not project)	TBD – 60 MW bids awarded in 2016 but projects are not yet built. Expect little to no residential participation.
HI	CBRE / HECO	$0.150	Held for 20 years	Required - at least 40% of project to subscriptions of 50 kW or less.	This is a fixed value for Phase 1 projects. Phase 2 will have the same fixed default value, but turns to bidding process	TBD – Program tariffs are under review. Industry response is not yet known.

[30] https://www.pge.com/tariffs/assets/pdf/adviceletter/ELEC_5232-E.pdf
[31] https://www.xcelenergy.com/staticfiles/xe/PDF/Regulatory/CO-Rates-&-Regulations-Entire-Electric-Book.pdf
[32] https://www.xcelenergy.com/staticfiles/xe-responsive/Working%20With%20Us/Renewable%20Developers/RenDevResCtr-SolarRewardsCommunity-Q32017-Dashboard.pdf
[33] Ibid

					if applications exceed capacity.	
IL	Adjustable Block Program / ComEd	~$0.06 (Residential) ~$0.03[34] (Lg. Comm.)	Base credit rate is energy supply portion only and floats over time, indefinitely.	Required for REC adder. Base REC plus REC adder (for project with > 50% small subscriber) pricing would be ~$0.07, fixed over 15 years of projected generation, though paid out in first 5 years of operation.	RECs are designed to make economics work. These rates also assume projects will utilize state-mandated $250/kW rebate (i.e., $500K for 2 MW project) for use of smart inverter.	TBD – Program has not yet been approved. Early indications are that it's expected to work.
MA	SREC II / National Grid	~$0.125 for projects from 1-2 MW-AC ~$0.175 for projects under 1 MW-AC	Floating small commercial retail rate. I.e., "host" rate for the system.	Yes - to qualify for premium REC. At least 50% of project to subscriptions of 25 kW or less.	Projects generate full-value SRECs (~$0.26/kWh) for 10 years; SRECs are monetized independent of the bill credit rate.	Yes – over 250 MW-dc capacity developed
	SMART / National Grid	~$0.10	Not yet confirmed, but likely to be set at Basic Service rate (supply component of retail rate)	Same as SREC II program above.	Total compensation set under SMART program regulations; total value of bill credit plus REC incentive will start at $0.20-0.22/kWh for 20 years and decline in subsequent blocks	Program has not launched yet, but industry interest is strong
MD	CSEGS / BGE	~ $0.13 (Residential) ~$0.07 (Lg. Comm.)[35]	Based on all volumetric charges associated with respective subscriber.	Not required. Unclear what participation level will be - higher rate for small subscribers may drive market there.	Three-year pilot program. RECs can be monetized, but value is currently low (> $10/MWh)	Yes – though Year 1 capacity is not entirely reserved for all utilities, due partly to land use/low-income challenges.

[34] https://www.comed.com/SiteCollectionDocuments/MyAccount/MyBillUsage/CurrentRates/Ratebook.pdf
[35] https://www.bge.com/MyAccount/MyBillUsage/Pages/RatesTariffs.aspx

MN	Pre-2017 Applications / Xcel	$0.13539 (Residential) $0.10515 (Lg. comm.)[36]	Annually updated subscriber retail rate (typical increase 1-2%), and honored for 25 years	Not required. Development shows only 12% of program capacity to residential, over 80% to large commercial.[37]	Projects can leverage (optional) fixed (25 year) $0.02/kWh REC adder for projects over 250 kW.	Yes - particularly for large commercial customers. Over 270 MW-AC in service at end of January.[38]
	2017 or later Applications Xcel	$0.1006, escalating to $0.1724 by year 25. Levelized = $0.1239. These are proposed – not yet confirmed.[39]	VOS rates updated annually, and vintage to project year of application. Includes REC as well as social cost of carbon compensation. Held 25 years.	Not required. Program is currently considering adder to incent developers to target residential customers.[40]		TBD -though, 69 applications submitted in 2017 suggests 2017 VOS works at least commercial.[41] 2018 VOS has raised concerns as too low.[42]
NY	Net metering / O&R	~$0.163 for residential subscribers	Based on all volumetric charges associated with respective subscriber.	Required - at least 60% of project to subscriptions of 25 kW or less.	Varies significantly by utility/load zone, ranging from $0.204 for ConEd customers to $0.09 for Rochester Gas & Electric customers	Development is robust in the utility territories with the highest rates outside NYC and minimal elsewhere.
	VDER / O&R	~$0.157 for Tranche 2 (~90% of retail rate)	"Value stack" including Market Transition Credit for residential and small	Required - at least 60% of project to subscriptions of 25 kW or less.	Varies significantly by utility/load zone, ranging from $0.17 for ConEd	Development is robust in the utility territories with the highest

36 https://www.edockets.state.mn.us/EFiling/edockets/searchDocuments.do?method=showPoup&documentId={10E25661-0000-C412-9CF2-F02761268D6B}&documentTitle=20182-139687-01

37 https://www.edockets.state.mn.us/EFiling/edockets/searchDocuments.do?method=showPoup&documentId={401F9661-0000-C713-A108-D739ED278E17}&documentTitle=20182-140096-01

38 Ibid.

39 https://www.edockets.state.mn.us/EFiling/edockets/searchDocuments.do?method=showPoup&documentId={C0CFDE5E-0000-CC1C-9F19-BC735EB0478B}&documentTitle=201710-136017-01

40 https://www.edockets.state.mn.us/EFiling/edockets/searchDocuments.do?method=showPoup&documentId={C046C461-0000-CD1F-A2DB-333E2F0A0192}&documentTitle=20182-140436-01

41 https://www.edockets.state.mn.us/EFiling/edockets/searchDocuments.do?method=showPoup&documentId={401F9661-0000-C713-A108-D739ED278E17}&documentTitle=20182-140096-01

42 https://www.edockets.state.mn.us/EFiling/edockets/searchDocuments.do?method=showPoup&documentId={4009735F-0000-C710-B8D1-AD0D69679ACF}&documentTitle=201710-136974-01

			commercial subscribers, set to allow value stack to equal 100%, 95%, or 90% of estimated retail rate		customers to $0.083 for NGrid Zone D customers	rates outside NYC and minimal elsewhere.
RI	CNM / National Grid	$0.153[43]	Floating small commercial retail rate. I.e., "host" rate for the system.	Required - only residential and low-to-moderate income customers are eligible.	RECs can be monetized.	Yes - though, program has been slow to pick up. Capacity remains available.[44]
	REG / NGrid	$0.189[45]	Rates developed annually based on third-party analysis of market. 20-year fixed rate.	Required - at least 50% of project capacity reserved for subscriptions of 25 kW or less.	This is a feed-in tariff REC purchasing program required to be offered through utility.	Yes – though relatively slow to pick up.

There are many take-aways from the above table, but it's worth calling out how several of these programs were initially established with some type of embedded cost credit rate before evolving to more complex methodologies. Massachusetts, Minnesota, and New York all provide good examples of community solar programs that built off of a foundation aligned with rooftop net metering. The simplicity of this approach from an administrative standpoint, and general familiarity and transparency for customers, developers, and financiers that were more accustomed to net metering offers a proven path to success for launching a community solar program.

Table 2 also illustrates that while there are a range of credit rates offered in community solar markets throughout the country (historically, currently, or projected), there are other equally important factors that should be considered along with those rates. For example:

- Are RECs or other incentives provided in the program?
- Do the rates float/escalate over time, or are the fixed?
- Does the program require participation by residential or small commercial customers?
- How successful has the program been in terms of capacity developed?
- How successful has the program been in terms of diverse participation, namely residential and small commercial customers?

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[43] https://www9.nationalgridus.com/narragansett/business/rates/4_c06.asp
[44] https://www9.nationalgridus.com/narragansett/home/energyeff/4_net-mtr.asp
[45] http://www.seadvantage.com/Documents/Eyes_and_ears_Library/RI/4774-DGBoard-DR-PUC1-14-Exhibit2-1.pdf

Without understanding – at least - these other aspects of the various programs, it's nearly impossible to make a fair comparison of the credit rates alone. As discussed in Section 3.3, cost considerations for Oregon could extend even deeper beyond what's captured in Table 3.

3.2.1 California In Focus

Of all these markets, California may tell the most compelling story. The Green Tariff Shared Renewables (GTSR) program was established to expand access to renewable energy resources to all ratepayers who are currently unable to access the benefits of onsite generation, and create a mechanism whereby all types of customers can meet their energy needs with generation from renewable energy. It consists of two subprograms: 1) a "Green Tariff" (GT) component designed for customers to pay the utility directly for solar generation that meets 50% or 100% of their electricity needs; and 2) an "Enhanced Community Renewables" (ECR) whereby a customer can purchase a share of an actual project from a solar developer in exchange for associated generation credits applied by the utility.[46] The ECR program is the true community solar opportunity in the program because it establishes a framework whereby customers could have an interest in a specific project – i.e., a tangible connection – rather than simply signing up for renewable energy more generally.

In aggregate, the GTSR program has set aside 600 MW to meet the demands of both of these programs. The utilities were required to procure a minimum level of capacity in the GT program and have since then been required to solicit twice a year for capacity in the ECR program. After several years of operation, the GT program remains less than 50% subscribed while the ECR program has remained completely unfilled with no capacity even procured. See Table 3.

Table 3. GTSR Procurement and Enrollment (to date)

Utility	GT Procured (MW)	GT Subscribed (%)	ECR Procured (MW)	ECR Subscribed (%)	Date
PG&E	52.75	44%	0	0%	2/28/2018
SCE	60	14%	0	0%	2/26/2018
SDG&E	20	22%	0	0%	2/27/2018

Why has the state with over six times more solar capacity than the next largest solar market[47], failing to develop any community solar out of a 600 MW program? Granted, there are layers of administrative burden that have made the application processes and ongoing requirements a costly and risky hurdle for developers. However, the economics and uncertainty rooted in the credit rate itself are at the heart of the program's failure to attract solar developer interest. The Solar Energy Industries Association (SEIA) continually raised the flag on this issue in the years leading up to the program launch and now, nearly two years later, the program remains

[46] http://www.cpuc.ca.gov/General.aspx?id=12181
[47] https://www.seia.org/research-resources/top-10-solar-states

untapped. As recently as last week – February 21 – the California PUC hosted a GTSR workshop focused on exploring the barriers to adoption for the ECR program specifically.

While the ECR program is burdened with administrative requirements that do not exist in other community solar programs, the most significant barrier is the bill credit rate, which is set too low for any project to be able to offer cost savings to subscribers. Not only is the credit starting out at an extremely low level, but the projections for that rate and components within it can fluctuate unpredictably from year to year, which further raises the risk and deters developers from attempting to develop projects within the program. The result speaks for itself.

3.3 Considerations for Oregon

Reviewing the credit rate practices – and particularly successes and failures - of other markets provides helpful context in approaching design and value considerations for Oregon. That said, each market has its own unique variables that impact project economics negatively and positively. Section 3.1 called out the importance of acknowledging the profile and number of subscribers per project as a real impact to financial modeling assumptions for project managers. While that is a clear factor with a requirement to reserve at least 50% of each project's capacity for residential and small commercial customers, there are numerous other variables that could impact project economics in Oregon's program. The following list attempts to capture most – though likely not all – of these considerations rooted in the program design, state and local policies, and federal policies.

- **TBD Program Costs and Benefits**
    - **Administrative Costs**. There is uncertainty regarding what the administrative costs will be for the program, and particularly any ongoing administrative costs that are intended to be recovered through developers and/or participants. There are several potential cost factors: Program Administrator fees; Low-Income Facilitator fee; and ongoing infrastructure costs associated with facilitating the exchange of data and dollars between customers, developers, and the utilities.
    - **On-Bill Payment**. The use of on-bill payment for community solar projects – regardless of whether they are managed by utilities or third-parties – should represent a level of cost savings for project managers since it should theoretically reduce the burden associated with "collections". The economic value of this remains to be determined.
    - **Low-Income Participation.** There remain key uncertainties regarding how low-income participation in projects and the program more generally will occur. What role exactly will the Low-Income Facilitator play? Will project managers be able to work directly with housing organizations rather than having relationships with each individual low-income customer? What, if any, incentives will be available to ensure low-income customers receive savings and/or that the cost of including low-income customers does not impede project development.

- **RECs and Other State Incentives**. As it stands, the community solar program will not be able to leverage RECs – as a monetization tool – or other incentives to drive down the cost of projects. RECs in particular have played a major role in subsidizing community solar in most markets across the country.
- **East vs. West Solar Resource**. Should only utility service territory dictated credit rate pricing, or should location influence the valuation as well? Oregon is a unique market with very significant difference in solar resource potential on either side of the Cascade Range which has a very real impact on project economics.

- **Varying Project Development Costs**
    - **Permitting / Land Use**. The Willamette Valley offers some of the best project development area for PGE customers, but much of that land is designated as "high-value farmland," creating significant challenges to develop on contiguous land greater than 12 acres which in turn limits project sizes. Projects could be limited to 2 MW or less and miss out on economies of scale. But even projects developed on 12 acres could – and already are[48] – facing challenges by local counties that are divided on solar development taking the place of traditional farming. Considerations for driving rooftop development.
    - **Interconnection.** Development east of the Cascades can incur significant interconnection costs due to an imbalance of generation to load. In addition, Pacific Power requires "relay-trip" schemes that burden < 5 MW projects with steep interconnection cost ($0.42/W). Average in other markets for same size systems are in low $0.20's/W. Interconnection capacity was greatly exhausted by pre-2016 ITC deadline requests. Many IOU service areas are infeasible by significant interconnection priority requests, higher protection and controls costs.
    - **Labor costs.** Oregon has restrictive requirements for solar installations, requiring "licensed" electricians for all electrical work. This can unnecessarily increase the project install cost significantly. There is also currently a huge shortage to supply construction demand. Wage risk is high and/or finding sufficient labor resources is very difficult.
    - **Property taxes.** Without standardized practices with valuing property taxes for solar projects, counties can vary significantly. Some counties in IOU service area refuse to adopt the in-lieu tax structure, charging rates that make direct grid connection projects infeasible.
    - **Land Acquisition:** Development of "green field" projects could prove to be difficult given the rush of QF activity prior to the avoided cost reductions. This could restrict the number of suitable site for solar development.

[48] Yamhill and Marion counties are proposing solar moratoriums or something similar in response to increased interest by solar developers.

- **Federal Cost Influence**
  - **Federal tax changes.** Reduces the tax equity market due to a lower tax threshold. Could be less tax equity providers and/or funds in an already limited field.
  - **Import Tariffs.** The import tariffs are a setback for the industry and can skew the reality of cost recovery estimates compared to projects developed in 2017. This can also create increased volatility for financing.
  - **Interest Rates.** If interest rates go up – which is expected give the current artificially low rates – financing costs could increase significantly.
  - **Future ITC stepdown**. Will the credit rate need to be adjusted to reflect changes in the Federal ITC?

It's difficult to anticipate the impact of all of these cost variables before project development, and ultimately the program, rolls out in force. The location, project size, and other project-specific dynamics create additional considerations.

4 Recommendation

The Solar Parties urge the PUC to establish a workable credit rate for Oregon's community solar program by April of this year. The RVOS will not be ready by that time, though even when it is ready (September at earliest), additional work will be needed to accommodate the methodology and (potentially) value to be compatible with a successful program. Most importantly, waiting another six months would ignore the numerous reasons for why stakeholders targeted April in the first place. We therefore make several primary and related recommendations: 1) use the "initial program capacity tier" to get the program off the ground; 2) for that initial tier, set a simple credit rate for each utility based on the current volumetric retail rates for residential customers for the respective utilities, and with an assumed 2% annual escalation over 20 years; and 3) explore the options for a successive tier credit rate as well as the role of the RVOS in the program. The following section explains these recommended options in more detail in addition to providing justification.

4.1 Leverage the Initial Capacity Tier

In Order 17-232, the PUC stated that their intention in setting the initial capacity limit (at 2.5% of each utility's system peak) was to "launch the program at a size large enough to sustain the initial administrative costs while also ensuring that we have the opportunity to adjust all aspects of the program before proceeding to any further expansion." In addition to helping sustain the program administrative costs, the initial capacity level also plays an important role in establishing a foundation to work with for the solar industry and market more generally. The Solar Parties believe 160 MW is a reasonable starting point and sufficient level for a variety of types of projects and project managers to participate in the program and ultimately serve a significant number of customers. 160 MW is also just large enough for project managers to justify investments in marketing and product development that can be standardized (and improved upon) in successive projects. This is an important consideration for a market we want to scale and grow sustainably.

Again, it's noteworthy that there are over 100 MW-ac of distributed solar generation capacity already installed or nearly installed in the state of Oregon.[49] The initial capacity tier of 160 MW in the community solar program represents a jump start to begin to catch up with the onsite/rooftop solar market and provide the majority of customers (at least in IOU territory) with an opportunity that has historically not been available to them. Providing an equitable opportunity for customers to participate in the costs and benefits of solar development and generation is a cornerstone to the importance of community solar as a state energy policy.

The Solar Parities also see the value in being able to adjust the program before further expanding and appreciate the flexibility built into the design with the Program Administrator and Implementation Manual. The credit rate, however, is an aspect of the program that requires as much transparency as possible. Most importantly, the rules are clear that projects will be able to lock in credit rates as they are pre-certified into the program thereby ensuring the value proposition offered to customers will not drastically change due to an unforeseen regulatory adjustment.

4.2 Leveraging the Retail Rate as the Basis for an Initial Credit Rate

In the interest of time, equity, and economic viability, the Solar Parties recommend using the residential volumetric retail rate as the basis for the credit rate in the initial program capacity tier. More specifically, the current year (2018) residential rate (including all delivery and supply service charges) would be established for each utility, from which a standard 2% annual escalation (or other rate based on historic escalation rates[50]) would be assumed over a 20-year duration.

Table 4. Residential Electricity Rates, Current and 20-year Levelized Values

Utility	2018 Rate	Levelized 20-Year Rate
Portland Gas Electric	$0.110[51]	$0.134
Pacific Power	$0.101[52]	$0.123
Idaho Power	$0.088[53]	$0.107

[49] OSEIA member meeting. ETO presentation.
[50] The state average residential retail rate increase (across all utilities) between 2007-2017 was closer to 3%/year. It may make more sense to use escalation rates that match the 10-year historic average annual rate increase for each utility.
[51] PGE. Schedule 007. Pulled Feb. 2018. https://www.portlandgeneral.com/-/media/public/documents/rate-schedules/sched_007.pdf
[52] https://www.pacificpower.net/content/dam/pacific_power/doc/About_Us/Rates_Regulation/Oregon/Approved_Tariffs/Oregon_Price_Summary.pdf
[53] https://www.idahopower.com/service-and-billing/residential/pricing-2/oregon-residential-rates/

These values – depicted in Table 4 above – are simple to calculate and provide reasonable initial capacity tier credit rates for the respective utilities. As discussed in a previous section, using a credit rate rooted from embedded cost rates has been the basis for getting most successful community solar markets off the ground. In most cases it's allowed community solar to begin catching up to the major advances enjoyed by the rooftop (onsite) solar market over the past 10-20 years. Further, while several markets either already have or are intended to embark on a new path with a more bottom-up credit rate methodology, they are doing so after establishing the momentum and experience of project development with an eye toward continued sustainable growth. Oregon is in a similar position as many of these other markets were several years ago, though with a crunching ITC deadline to boot.

Using a completely transparent fixed rate (with fixed escalator) for each utility is more desirable for financiers – and therefore project managers – and in itself can reduce costs by reducing financing risks. While basing the fixed rate off the residential class may seem high for large commercial or industrial customers, note that project managers dictate the cost of participation by subscribers and need to provide savings to all subscribers to make a project financeable. Further, the program's requirement to reserve at least 50% of each project's capacity for residential and small commercial customers provides a policy safeguard that ensures program benefits are not exploited by large commercial customers.

The Solar Parties note our concern with simply using the subscriber's retail rate (which is different for each customer class and floats over time), that it will be too low for large commercial and industrial customers (nearly half the residential and small commercial rates), and result in project managers avoiding those customer segments due to an inability to produce savings. This would be an unintended program result and could also negatively impact project economics overall which can benefit from leveraging the security of large customer participation as anchor tenants.

A fixed rate (with a fixed escalator or levelized) is also administratively easier – for both the utility and Program Administrator - to manage calculations and crediting than a floating rate and supports a more intuitive and transparent value proposition for customers. Note, in general, it's preferable to the industry to have these values escalate each year rather than using a levelized value fixed over the full 20-year duration.

Finally, there are limits built into the rules with regards to bill crediting which prevent abuse (actually to the point that it creates what is arguably an unfair burden) associated with bill crediting. Specifically, there are two monthly bill crediting limits: one that caps the generation (kWh) credits applied to a monthly bill at the level of the customer's respective consumption for that month; and the second which caps the dollar ($) credit value for a given month at the amount for the respective customer's volumetric electricity charges for that month. With this latter cap, large commercial and industrial customers will be limited to benefits that do not exceed their volumetric electricity costs – similar to residential and small commercial customers.

4.2.1 Will the residential rate be enough to ensure customer savings and active interest in the program by developers and project managers?

We cannot definitively say whether our proposed credit rates will work in the program. As laid out previously in the "Considerations for Oregon" subsection, there are many variables at play in determining project economics and there remains significant uncertainties associated with issues such: program administrative costs; low-income participation; land use costs and availability; interconnection costs; and others. Further, in comparison to rates used in other parts of the country Oregon's would be relatively low, which could particularly penalize projects located west of the Cascade Range. However, we do feel this is a reasonable – if not minimum - starting point which can drive project manager engagement immediately toward deeper project development investments and milestones. It can also help inform and guide the design of other important and outstanding implementation elements of the program that have financial impacts, such as low-income participation and ongoing administrative costs. If it's determined that these rates do not work, we can build off of that, but waiting for the RVOS or attempting to develop some other complex methodology will compound other implementation delays and ultimately continue preventing any real community-solar focused development in the market, at the risk of waiting for something that does not even work anyway, and is too late to leverage the 30% ITC.

4.3 Determining a Credit Rate for Successive Capacity Tiers

The Solar Parties view the recommendations above as near-term critical actions to initiate project development, and ultimately allow the PUC and stakeholders to move forward in addressing the remaining program implementation details. That said, we are also interested in continuing the conversation on what the credit rate could or should be in successive capacity tiers, and what role the RVOS can or should play in any tier. As demonstrated in Table 2 (Section 3.2), there are many options for designing a successive tier credit rate. Whether and how that rate could incorporate the RVOS is still to be determined, but it's clear to us that the RVOS is not ready – now or in September - to automatically slip into the community solar program.

5 Conclusion

The Solar Parties appreciate the hard work done by the PUC, Staff, and all involved stakeholders in getting the program design and implementation to where it is today. We're at a critical juncture that could literally make or break the success of the program and we hope that our input is taken sincerely and seriously. The national solar industry made similar warnings to the California PUC in the build up to the GTSR-ECR program roll out in 2016 and that program continues to struggle to this day. We have an opportunity to learn from their mistakes and establish Oregon's leadership in community solar on the West Coast.

Respectfully submitted,

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APPENDIX

Community Solar Program Example Timeline (Months 1-12)

Time to complete task	3MW project timeline assumptions		Month 1	Month 2	Month 3	Month 4	Month 5	Month 6	Month 7	Month 8	Month 9	Month 10	Month 11	Month 12
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		
1 month	Procurement													
2-4 months	Construction													
1 month	Community Solar final certification													
	Timeline to Full ITC - starting construction in 2019	**Dec-17**	**Jan-18**	**Feb-18**	**Mar-18**	**Apr-18**	**May-18**	**Jun-18**	**Jul-18**	**Aug-18**	**Sep-18**	**Oct-18**	**Nov-18**	**Dec-18**
	Major Milestones					M1					M2	M3		M4
						Site Control					System Impact Study complete	CS Pre-Certification complete		Non-ministerial permits complete

Community Solar Program Example Timeline (Months 13-27)

Time to complete task	3MW project timeline assumptions	Month 13	Month 14	Month 15	Month 16	Month 17	Month 18	Month 19	Month 20	Month 21	Month 22	Month 23	Month 24	Month 25	Month 26	Month 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											
1 month	Procurement															
2-4 months	Construction															
1 month	Community Solar final certification															
	Timeline to Full ITC - starting construction in 2019	**Jan-19**	**Feb-19**	**Mar-19**	**Apr-19**	**May-19**	**Jun-19**	**Jul-19**	**Aug-19**	**Sep-19**	**Oct-19**	**Nov-19**	**Dec-19**	**Jan-20**	**Feb-20**	**Mar-20**
	Major Milestones			M5	M6				M7		M8			M9	M10	
				Subscriber acquisition complete	Interconnection complete. Agreement signed				Building permits complete		Start Construction			Construction Complete	CS final Certification Complete	