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# Joint Comments on Behalf of the Oregon Solar Energy Industries Association and Coalition for Community Solar Access in UM 1930

## April 17, 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.

The following comments are in response to the Public Utility Commission Order 18-088 (filed March 19, 2018) and the Staff Report filed April 10 regarding "Interim Alternative Bill Credit Rate Proposals for Community Solar." The Solar Parties appreciate the Commission's dedication to establishing an interim credit rate as soon as possible and creating this opportunity for dialogue. We also appreciate the effort by Staff to develop credit rate options and a solid framework for weighing potential trade-offs of the options.

We've organized these comments into four primary sections: Executive Summary; Recommendations; Critique of the Staff Report's 2nd and 3rd Options; and Conclusion.

# 1 Executive Summary

- The Solar Parties recommend adopting a variation on the Staff Report's Simple Retail Rate option (Option #1): the <u>residential retail rate with a 2% annual escalator</u>.
    - This is the simplest solution and requires the least amount of time to implement.
    - ETO's analysis demonstrates it is the minimum rate to achieving "active project development and customer participation", as identified in Order 18-088.
    - Emphasizing simplicity, some additional flexibility could be incorporated to support cost recovery for smaller projects, low-income participation, and/or administrative fees.
- The Solar Parties recommend applying the interim credit rate to the "initial capacity tier" before considering a transition to an RVOS-based rate.
    - The initial capacity tier was established to launch the program at a size large enough to sustain administrative costs while allowing for adjustments before further expansion.
    - Breaking up the initial capacity tier risks further delaying long development and investment cycles and not leveraging the highest available federal incentives.

*Table ES. Modified Option Comparison*

| Principles | Option 1 - variation (Solar Parties) Residential Retail w/ 2% Adder | Option 1 (Staff Report) Simple Retail | Option 2 (Staff Report) Adjusted Retail | Option 3 (Staff Report) Adjusted RVOS |
|---|---|---|---|---|
| **Simplicity** | X | X | | |
| **Accessibility*** | X | | | |
| **Can incorporate variation based on project type** | X | | X | |
| **Minimizes cost shift** | X | X | X | X |
| **Transition to RVOS** | X | X | X | X |

*".. results in active project development and the availability of subscriptions to customers" (Order. 18-088)*

- The Adjusted Retail Rate (Option #2) and Adjusted RVOS (Option #3) do not work economically.
    - The Staff Report's analysis supporting Option #2 and #3 lacks justification and does not account for: embedded costs identified by ETO; the need to provide customer savings; and potential costs from low-income participation and program administration.
- The design and administration of Options #2 and #3 are overly complex and inconsistent with the aim of establishing an interim credit rate that is simple, immediate, and drives accessibility.
    - Reverse auctions create greater uncertainty and speculation in the market, increase overhead costs, and match poorly with customer-focused programs.
    - Incremental capacity allocations and/or rate adjustments prevent or delay project development and disrupt market momentum.
    - The RVOS is not final and any current or past filings should not be construed as such.

# 2 Recommendations

The Solar Parties make two primary recommendations: adopt the residential retail rate with a 2% annual escalator as the interim credit rate; and apply that methodology to the full initial capacity tier for the program. The following section provides justification for those recommendations in addition to highlighting potential considerations for incorporating flexibility with that rate.

## 2.1 Rate Recommendation – Residential Retail Rate that Reflects Forecasted Inflation

The Solar Parties have reviewed the Staff Report and find that of the three options proposed, a variation on the residential retail rate option (Option #1) provides the greatest opportunity for achieving the objectives identified by the PUC in Order 18-088. In addition, we recommend a 2% annual escalator be incorporated with the residential retail rate to further account for the costs of community solar. In combination, this is the simplest solution for creating a real opportunity to spur development and ensure the program is made accessible to customers.

### 2.1.1 Justification for the Residential Retail Rate

The residential retail rate is a good fit as the interim credit rate for Oregon's community solar program, as it can meet all of the Guiding Principles identified in the Staff Report and higher-level objectives outlined by the Commission. Of the proposed options included in the Staff Report, the retail rate also has clear advantages over the other options in meeting the goals of simplicity and accessibility. It's also reasonable with regards to national experience and weighing the costs and benefits to the program and ratepayers.

- Simplicity
  - The residential retail rate is simple and available, takes little to no administrative effort to establish, and aligns with the PUC determination that a program should be developed in a timely manner, with rates available ideally in April.
  - It provides immediate transparency and certainty to the industry and development community to more confidently analyze and engage the Oregon market.
  - It's easy for customers to comprehend in determining the costs and benefits of the program and specific projects, which can also help reduce marketing and customer acquisition costs.
- Accessibility
  - The Solar Parties believe, and the ETO analysis supports, that the residential retail rate with a 2% escalator should be sufficient to make projects pencil and ultimately align with the PUC determination that a "functioning program" should equate to creating opportunities for customer participation.
  - The cost analysis accompanying the Staff Report demonstrates that Options #2 and #3 will not produce bill credit rates that are sufficient to support project development and customer savings. This is a threshold problem for these two options: They are unlikely to lead to a functioning program. Moreover, there are additional project costs and risks that are not fully incorporated into the Staff Report's analysis, including potential unforeseen costs associated with the program (e.g., administrative fees and low-income participation) and uncertain costs associated with project development (e.g., permitting and interconnection).

- Reasonableness
    - Using a bill credit based on the retail rate has been the tried and true policy tool for community solar markets getting off the ground across the country (e.g., MA; MD; MN; NY; and RI).
    - Of the options laid out in the Staff Report, the residential retail rate is the only option that offers the possibility of customer savings, which will be necessary to allow community solar providers to finance and build projects. The residential retail rate is generally lower than the average project costs for large projects based on ETO's analysis (which doesn't even fully account for all costs, such as customer savings, and potential program administration and low-income costs, etc.).
    - The estimated cost is very modest: The Staff Report estimates a bill impact of only about 0.25% (an additional 25 cents on a $100 utility bill) if the first tier of program capacity is authorized at the residential retail rate.

### 2.1.2 Justification for the Rate Escalator

While the Solar Parties are supportive of using the residential retail rate as the interim credit rate for the program, we reiterate our concern that a flat residential retail rate alone will not pencil for the majority if not all large projects, and therefore projects of smaller size are considerably more unlikely. This conclusion is based on ETO's independent analysis and is borne out by observations of CCSA member companies. The following table provides a comparison of: Option #1 from the Staff Report (i.e., fixed residential retail rate); the Solar Parties recommendation (residential retail rate with a 2% annual escalator); and the "average" embedded cost rates determined by ETO's analysis for, large (4 MW-dc), medium (2 MW-dc), and small (500 kW-dc) projects.

***Table 1. Comparison of Rates from Staff Report, Solar Parties, and ETO***

| **Utility** | **Staff Report Option** | **Solar Parties Option** | **ETO Analysis - "Embedded Cost"** | | | |
|---|---|---|---|---|---|---|
| | **Simple Retail** | **Retail w/ 2% Escalator 20-Year Levelized** | **Location** | **Large (Avg. $)** | **Medium (Avg. $)** | **Small (Avg. $)** |
| **PGE** | $0.1103 | $0.1340 | ***Portland*** | $0.151 | $0.163 | $0.175 |
| **PAC** | $0.1005 | $0.1230 | ***Bend*** | $0.117 | $0.127 | $0.136 |
| | | | ***Klamath Falls**** | $0.090 | $0.097 | $0.013 |
| **IPC** | $0.0880 | $0.1069 | N/A | | | |

The ETO "averages" for embedded costs are nearly all higher than the Option #1 (Simple Retail) rates, with the exception of tracking systems located in Klamath Falls. In addition, as noted elsewhere in these comments, the ETO analysis did not incorporate proxy assumptions associated with program administrative fees or low-income participation costs. It also did not incorporate any expected customer savings, which the Solar Parties have highlighted previously as a critical financing prerequisite for community solar projects (see OSEIA-CCSA comments from March 1, pgs. 6-7). For example, in Illinois the price points developed for RECs are based on an assumption that 20% of the bill credit rate value stays with the customer (i.e., customer savings), and therefore project managers only receive 80% of the credit rate value.[1] Finally, there remain a wealth of other cost considerations (see OSEIA-CCSA comments from March 1, pgs. 18-20) that can easily alter project economics, such as interconnection challenges (anticipated for projects located east of the Cascades) and permitting challenges (already being experienced in PGE territory).

The escalator is essentially an inflation forecast that will likely keep the program credit rate roughly on par with actual floating retail rates. Rates generally increase each year: the Oregon state average residential retail rate increase (across all utilities) between 2007-2017 was close to 3%/year.[2]. The Solar Parties are amenable to using a floating rate instead. That said, an established rate with a fixed escalator is preferable over a floating rate (which adjusts each year) because it provides certainty to developers and therefore lowers financing costs. It also benefits the utility and Program Administrator in enabling easier management of calculations and crediting processes, in addition to being able to more accurately forecast cash flows.

Note, it's also preferable to the industry and customers to have these values escalate each year rather than using a levelized value fixed over the full 20-year duration.

### 2.1.3 Addressing PUC Concerns

The Staff Report calls out potential limitations of using a simple retail rate in meeting the designated Guiding Principles which are consistent with points raised by the PUC. Specifically, a fixed rate would only differ by utility and therefore lack a "locational" recognition of distribution system value. In addition, a fixed rate would reduce flexibility in responding to potential cost-shifting. The Solar Parties have responses to both of these concerns.

#### *2.1.3.1 On the Concern for Locational Benefits*

The Solar Parties recognize and appreciate the PUC's interest in providing market signals to drive solar development toward locations where it provides the greatest grid value. This is one of the several unique benefits of solar generation which the industry is proud to support. However, there are a few reasons why it is not necessarily needed or appropriate to attempt to create location-specific valuations at this time, including:

- Due to their small size, most if not all community solar projects will interconnect at the distribution level, rather than the transmission level. Thus, while the distribution feeder adder proposed by Staff has value in principle, in practice it is likely that all community solar projects would qualify for it. It would be easier to simply incorporate this value into the bill credit rate.
- The data is simply not yet available to indicate where the greatest distribution system benefits can be incurred. This is a future value that will likely be explored and incorporated as part of the RVOS in future years.
- Additional consideration may be needed for "projects" that utilize multiple systems, for example one larger system located further away from load and another partnering smaller system (part of the same "project") located closer to load.

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[1] Illinois. Long-Term Renewable Resources Procurement Plan. See Appendix D, found here: https://www2.illinois.gov/sites/ipa/Pages/Renewable_Resources.aspx

[2] EIA. See Tables 5.6.B for annual summaries from 2007-2017. Found at: https://www.eia.gov/electricity/monthly/

That said, there is potential for providing some level of support for smaller-sized systems, which generally correlate with rooftop projects and those located more closely to load. See Section 2.1.4 “Considerations Regarding Rate Adjustments.”

#### *2.1.3.2 On the Concern for Cost-Shifting*

The PUC has maintained a clear concern for cost shifting and an interest to keep it as minimal as possible without compromising the ability of the program to actually be functional and accessible to customers. The Solar Parties appreciate the need for balancing these objectives. In response to the Staff Report’s suggestion that utilizing the simple retail rate represents the greatest cost shift risk of the proposed options the Solar Parties make the following comments and observations:

- There is still complete uncertainty with regards to the RVOS, which in turn undermines any predictions of cost shifting from distributed solar programs. For example, testimony filed by OSEIA in the utility dockets relating to UM 1716 show RVOS values could be nearly double, if not more, than what was initially filed by the utilities.[3]
- The goal is to achieve minimal cost shift possible <u>while</u> simultaneously enabling project development, and ultimately an opportunity for customer participation. If the credit rate is too low, there will be no development and the concern with cost shifting will be meaningless. The retail rate creates a higher cost shift in the Staff Report relative to the other options, but that’s largely because the other options are not economically viable for development.
- Cost shift numbers provided in the Staff Report are relatively negligible. Based on the assumptions in the Staff Report, if the simple retail rate option (Option #1) was held flat for the entire initial capacity tier of the program, there would be about a quarter of a percent rate increase for PGE and Pacific Power customers.[4] Even with an escalator, the impacts would be less than half a percent for these utility customers. This is well below the level (~1%) that the Citizens Utility Board (CUB) suggested as a reasonable limit for the program during the March 5th workshop.

### 2.1.4 Considerations Regarding Rate Adjustments

While an important advantage of the residential retail rate is its simplicity, it can also be adjusted to reflect variations in project type, as described in Order 18-088. These adjustments could be implemented in parallel to establishing the base credit rate or could be established in the coming months as an Administrator is selected and the program implementation comes to fruition.

- The residential retail rate with an escalator could be the baseline credit rate for the program, but smaller projects could receive a higher rate. For example, in Illinois the base REC pricing for community solar projects is about $0.025/kWh higher for projects that are 500 kW or less compared to those that are up to 2 MW in size.[5]
- Additional support for smaller projects could be made through a small capacity carve out over an initial period of the program launch (e.g., 6-12 months). The Solar Parties find that a reasonable capacity carve-out could be 5-10 MW for projects at 500 kW or less.

[3] Beach, T. See Table ES-1. http://edocs.puc.state.or.us/efdocs/HTB/um1910htb135541.pdf
[4] This is based on a simple doubling of the percentages provided in the Staff Report, as that analysis was focused on 50% of the program capacity.
[5] IPA. Long-Term Renewable Resource Procurement Plan. Found here: https://www2.illinois.gov/sites/ipa/Pages/Renewable_Resources.aspx

- Additional financial support may be needed for addressing the low-income participation requirements in the program, including the per-project requirement and the additional portion of the program dedicated to low-income focused projects.
- Given the high level of uncertainty associated with the administrative costs for the program, this costs may also be flagged as something that is potentially built into or on top of the credit rate to avoid overly burdening the participants and dissuading demand from developers.

The Solar Parties provide these considerations while cautioning against becoming overly complex in incorporating adders and adjustments in this first phase of the program.

## 2.2 Transition Recommendation – Reserve the Initial Capacity Tier Before Evaluating Potential RVOS Transition

The Solar Parties reiterate our initial recommendation to apply the interim credit rate to the full "initial capacity tier" (~160 MW-ac) of the program. (see OSEIA-CCSA Comments filed March 1, pgs. 20-21) It's in the best interest for the PUC, industry, stakeholders, and all other ratepayers to have the entire initial capacity tier (~160 MW) reserved within the first 12 months of launching the program. Justification was previously provided in those initial comments, however here are a few key points worth reiterating:

- The federal ITC steps down for commercial projects from 30% to 26% in 2020, then from 26% to 22% in 2021, and then to 10% thereafter.[6] These drops are becoming an increasing reality as we wait for the program to complete its remaining significant implementation details, and represents a huge savings opportunity for Oregon's program. A disruption to the initial capacity tier allocation could delay development and further expose the program to missed savings, and in turn drive a need for higher credit rates in order to sustain the market.
- As envisioned by the Commission in Order 17-232, the initial capacity tier was, itself, established to launch the program at a size large enough to sustain administrative costs while allowing for adjustments before further expansion. I.e., there is already a built-in safety "stop and review" point to consider major program adjustments. Additional stop-gaps create more delays and administrative burden on the Commission, Program Administrator, and Staff.
- 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, scaled, and improved upon in successive projects.
- Even if the entire capacity was allocated in the first 12 months of the program launch, it could take two years or more for projects – especially larger projects – to actually be built and operating in the market. Long development and investment cycles make small program sizes impractical and more expensive.
- The DG market for the IOUs is currently at about 80-90 MW-ac installed and rapidly growing.[7] 160 MW of community solar being developed over the next few years – in parallel to the

[6] https://www.seia.org/initiatives/solar-investment-tax-credit-itc
[7] Discussion with Energy Trust of Oregon. April 12, 2018. ETO sees about 105 MW-dc currently installed in the state and expects between 110-120 MW-dc to be installed by year's end.

continued growth of the onsite DG market - will ensure equitable opportunities for participating in the costs and benefits of solar generation.

- Full build-out of the initial capacity tier is needed to ensure that the cost of administering the program can be recovered efficiently.

### 2.3 Other Transition Considerations

Regardless of when the transition occurs or begins to occur, the Solar Parties highlight the importance of ensuring a smooth transition that aims to not disrupt market growth. Any change to rates should be gradual and incorporate stakeholder-involved processes that recognize market demand and cost realities. Similarly, such evaluations should begin prior to when the actual trigger point occurs to avoid creating delays and uncertainty in the market. For example, discussions should begin as the target capacity level (i.e., initial capacity tier) is approaching being fully pre-certified, as opposed to waiting for it to actually be built and operating. Importantly, as highlighted in Order 17-232, the bill credit rate in effect when a project is pre-certified must apply for the term of the contract and not be exposed to any subsequent rate changes.

## 3 Critique of Project Economic Assumptions and Design Elements for Options #2 and #3

The Solar Parties find that the Staff Report is thoughtful and well-framed, and we are supportive of the “Guiding Principles” identified and thorough consideration of potential “adjustment factors” and “transition mechanisms”. However, the credit rate options proposed in the Report do not adequately incorporate the best available data and information and – particularly Options #2 and #3 – would fail to achieve the desired objective of establishing simple credit rates that enable a successful (i.e., accessible to customers) program to be launched as soon as possible.

This section first highlights the primary inadequacies of the Staff Report’s assumptions associated with project economics for community solar in Oregon, followed by a deeper evaluation of design elements of credit rate Options #2 and #3.

### 3.1 Underlying Concerns with Staff’s Rate Analysis

The Solar Parties greatest underlying concern with the Staff Report is its failure to adequately account for and incorporate economic data associated with community solar projects. We understand and appreciate the need for minimizing cost shift in the program, but if no projects are developed because they simply don’t pencil the cost-shift concern becomes a moot point.

While the rate methodology proposed for Option #1 (Simple Retail Rate) in the Staff Report is straightforward, the calculations used for Options #2 and #3 are less justified. For example:

- Option #2 uses the midpoint between the residential rate and QF avoided cost rate as the ceiling price for large projects bidding into the program. Footnote 19 suggests that this “midpoint” determination was: “Based on Staff’s finding that large community solar projects are a hybrid of a residential distributed solar project and a QF solar farm.” This may be a convenient way to understand community solar from a philosophical perspective, but it lacks merit or evidence as a valid source for determining actual project economics.

- Option #3 uses the initial RVOS values submitted by the utilities in late 2017, and adds a "market transition credit" (MTC) and "distribution feeder adder" (for projects located on distribution system) to produce a total potential credit value. This methodology is flawed in several ways: it's utilizing base rates (RVOS) that remain undetermined in contested cases for each utility; and it calculates the MTC based on the LCOE of the 30% ITC without any other justification.

The methodologies used for Options #2 and #3 are not only hard to justify, but, more importantly, result in rates that will not work economically. Greater focus is needed on where the rates need to end up to make the program functional, rather than the creativeness of the methodology for achieving those rates. The Staff Report acknowledges but does not appear to incorporate the input previously provided by the Solar Parties as well as an analysis provided by the Energy Trust of Oregon with regards to potential rate values.

- The Solar Parties provided a fairly comprehensive summary of credit rates for community solar programs across the country including the various success levels and other important considerations, such as requirements associated with small subscriber (residential and small commercial) participation. (See Table 2 in the OSEIA-CCSA Comments submitted March 1). While there is a range of credit rates being utilized, successful programs in the country that also require small subscriber participation have credit rates in the mid-teens (cents/kWh) when accounting for associated RECs and other incentives.
    - Importantly, all successful community solar programs in other states offer customers the potential for cost savings, while programs designed with a bill credit priced at a premium have been unsuccessful in spurring project development. While there has been customer interest in Oregon's premium-priced green tariff programs, these programs are fundamentally different from community solar. In a green tariff program, projects are financed based on a contract with the utility; low customer interest does not jeopardize the project's revenues. In a community solar program, projects are financed based on long-term subscription agreements with customers. Financing providers must be convinced that customers will continue making payments for the full term of the contract; in practice, this requires a bill credit that offers savings to customers.
- Results of an ETO analysis are included as an attachment to the Solar Report, in which a range (low, average, high) of potential "embedded costs" for community solar projects of several sizes (extra small, small, medium, large), locations (in locations with different solar insolation (Portland, Bend, and Klamath Falls), and two technology types (fixed and tracker) are evaluated. The high-level analysis takes into account system development and installation costs, financing, and O&M, in addition to the incremental costs of community solar associated with customer acquisition and ongoing customer management. Notably, this analysis does not assume a level of customer savings or take into account the additional costs associated with program-level administrative fees or any additional costs that could be incurred from low-income participation. The ETO analysis provides a very useful benchmark, however the results should be viewed as aggressive since they do not include all costs that need to be recovered by project managers.

Given the lack of incorporating these other components and other general uncertainties with solar development in Oregon, the Solar Parties recommend that at least the "average" embedded cost values be used as a comparison point or target for the program's initial credit rate. As discussed in Section 2.1, these average rates would match reasonably well with an annually escalated residential retail rate, and are roughly consistent – though generally lower - to national trends. Conversely, the Staff Report methodologies produce values that largely fall below even the "low" embedded cost results.

The following table highlights the discrepancy between the proposed rates (for large projects) in Option #2 and #3 relative to both the range and average of rates (for large projects) calculated by ETO for projects in Portland, Bend, and Klamath Falls.

*Table 2. Comparison of Staff Options and ETO's Embedded Cost Analysis*

| Utility | Staff Report Options | | | ETO Analysis - "Embedded Cost" | | |
|---|---|---|---|---|---|---|
| | Simple Retail | Adjusted Retail[8] | Adjusted RVOS[9] | Location | Range | Average |
| **PGE** | $0.1103 | $0.0761 | $0.0999 | ***Portland*** | $0.114 - $0.202 | $0.151 |
| **PAC** | $0.1005 | $0.0716 | $0.0828 | ***Bend*** | $0.088 - $0.158 | $0.117 |
| | | | | ***Klamath Falls[10]*** | $0.066 - $0.121 | $0.090 |

Based on this comparison, few of the modeled projects would even have a chance of being economically viable under Option #2 or #3, and these would be concentrated in specific areas of one utility service territory. These options would not deliver a broadly accessible community solar program.

## 3.2 Concerns with the Design and Administrative Elements of Options #2 and #3

In addition to addressing the above concerns associated with the actual values proposed in Options #2 and #3, the Solar Parties highlight the following issues associated with the design and implementation of those Options.

### 3.2.1 Issues with the Design of Option # 2 – Adjusted Retail Rate

As discussed in Section 2.1.4 of these comments, the Solar Parties are cautiously receptive to the idea of incorporating adjustments to the residential retail rate to achieve certain policy objectives such as low-income participation and providing cost recovery for different project size costs. That general logic is reasonable, however the complexity included in the design of Option #2, particularly the proposal for a reverse auction and the use of incremental capacity allocations, directly counters the goal to establish a simple and transparent credit rate to fuel near-term project development and lay the foundation for market momentum over the long run.

A reverse auction would be inconsistent with the PUC's intent to get a program, and ultimately projects, established quickly. It's also a bad policy tool for administering a community solar program. The following lists identifies key issues and concerns with a reverse auction being used to administer the interim rate for the program.

[8] This is the ceiling price for large projects.
[9] Incorporates MTC and distribution adder.
[10] Utilizes tracking system.

- **Reverse auctions are complicated and costly to set up and administer.** A community solar reverse auction in particular would likely take additional time and stakeholder feedback to develop as it may need to incorporate qualitative, not just quantitative, components of a project (see pre-certification requirements). Even after being established, the process of holding solicitations, bidding and awarding processes creates additional delays for the market to move – potentially jeopardizing the ability to meet the ITC step down deadline. In addition to the hindering complexity and time delays, establishing and administering ongoing auctions will also create excess administrative costs that will need to be recovered.
- **Reverse auctions create greater uncertainty for the market.** Establishing a reverse auction now, even with an identified ceiling price, creates additional risk and uncertainty for developers. This is not consistent with what stakeholders and industry were advocating for in requesting the establishment of a credit rate by "April," and it does not guarantee success or accessibility of the program. The increased complexity of an auction process is also challenging for bidding as it can create arbitrary and inconsistent goal posts and lead to market biases and/or hinder the ability for participation by less sophisticated developers.
- **Reverse auctions incent speculation and bad actors**. A reverse auction can drive speculating solar developers to bid at rates that may not realistically pencil, in order to hold a position in the queue. This can fuel development delays and drop-outs. This "race to the bottom" can also result in compromising the quality of the project and associated products and services.
- **Reverse auctions are a bad policy match for community solar.** A reverse auction may make sense to force developers to compete simply on the cost of building a solar system, but community solar involves interactions with hundreds (if not thousands during marketing) of retail customers. Not only can these incremental costs be difficult to quantify, but they're also an aspect of the project that should not be compromised. Costs shouldn't be the only criteria to support a diverse thriving community solar market.

In addition to the reverse auction, the processes proposed in Option #2 with regards to incremental capacity allocations and associated rate adjustments (including the 5% and 15% incremental capacity allocations, the 12-month review of market demand, and the "auction windows" for large projects) create more uncertainty and stumbling blocks that will hinder the growth of the market. These frequent re-adjustments would consume significant Staff and Program Administrator resources. They would also make the program much less transparent and more risky for project managers dealing with project development cycles of 18 months or more. As explained in Section 2.2, the Solar Parties believe it would be most efficient to authorize the entire initial capacity tier of the program under a uniform bill credit rate approach.

### 3.2.2 Issues with the Design of Option #3 - Adjusted RVOS

The Solar Parties already flagged the arbitrary nature of determining Option #3. Namely that any filings associated with the RVOS are essentially meaningless until that case has been settled (September at the earliest). For example, not only could final RVOS values be drastically different than the initial filing values, but the initial filings were also preliminary in nature and made no assumptions regarding community solar administrative costs or how those would be recovered. Further, the analysis behind the MTC doesn't appear to be working toward a total target rate that will ensure project development actually occurs. In addition to those concerns, the Solar Parties would also flag that the proposed drop in the MTC (50%, or $0.02) at 25% (~40 MW) of the total capacity tier is way too drastic in too short of a period. A $0.02 drop in the credit rate would be a 20-25% impact on the project revenue (based on currently proposed rates) and essentially create a "cliff" for the market. For comparison, in Illinois the REC price for community solar will decrease by 4% each time ~52 MW is allocated in the community solar program.[11]

Again, the Solar Parties reiterate their first position to let the interim credit rate ride out with the full initial capacity tier, but at the very least there should be no major changes.

# 4 Conclusion

The Solar Parties find an overwhelming case for leveraging the residential retail rate with an escalator as the interim rate for the "initial capacity tier" of Oregon's first state-level community solar program. We are most aligned with Option #1 of the Staff Report, however we recommend the addition of an escalator to ensure a greater likelihood of project development and therefore customer participation across the utility service territories. We are also amenable to incorporating some level of flexibility in the rate design to accommodate smaller projects, and to address potential costs associated with low-income participation and program administration fees.

We appreciate the organizing structure of the Staff Report and creative proposals for varying credit rate options, however we identify flaws with the underlying analyses as well as design issues which directly conflict with the aim of establishing a simple credit rate that fosters an active market response.

Thank you for considering these comments. We look forward to the hearing on April 24, and subsequent opportunities to collaborate with the Commission, Staff, and other stakeholders in developing this critical component of Oregon's community solar program.

Respectfully submitted,

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[11] This refers to ComEd (Group B) projects only. See Filed Plan. https://www2.illinois.gov/sites/ipa/Pages/Renewable_Resources.aspx