ORDER NO. 19-392

ENTERED Nov 08 2019

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UM 1930

In the Matter of PUBLIC UTILITY COMMISSION OF OREGON, Community Solar Program Implementation.	ORDER

DISPOSITION: FINAL ELEMENTS FOR COMMUNITY SOLAR PROGRAM ADOPTED

In this order, we memorialize our decision made and effective at the October 29, 2019 Special Public Meeting, to adopt additional elements of the Community Solar Program (CSP). These elements required resolution prior to program implementation. We adopt Staff's recommendations, except where noted in this order. The Staff Report is attached as Appendix A.

I. BACKGROUND

On October 4, 2019, Staff filed a report containing several recommendations for the CSP. Staff noted that four policy areas (bill credit rate, transition to ongoing program administration costs, low-income requirements, and interconnection) were significant and complex, and required resolution prior to pre-certification of projects, set to begin on December 16, 2019.[1]

Stakeholders filed comments in response to the Staff Report. At the October 22, 2019 Public Meeting, Staff presented their recommendations. A large and diverse group of stakeholders also provided comment at that time. We appreciate the consistent interest and substantive participation from stakeholders during this nearly two-year implementation docket. We also commend Staff for their diligence in developing thoughtful recommendations within the guidelines of the statutes and rules for our consideration.

[1] Staff Report at 2 (Oct 4, 2019).

On October 29, 2019, we held a Special Public Meeting to deliberate on Staff's recommendations. Staff provided a summary of its analysis, potential alternatives to its recommendations, and information regarding the impact such alternatives might have on the CSP moving forward. After considering each Commissioner's individual perspective on Staff's recommendations and the feedback from stakeholders, we made the determinations reflected in this order.

II. DISCUSSION

Our decision represents a balance that must occur between the two primary requirements of CSP implementation. The first is incentivizing customer participation. The legislature directed us to develop a program that provides a meaningful opportunity for electric utility customers to participate in community solar projects. Customer participation requires the availability of CSP project offerings. Therefore, we must act to ensure that the CSP design will encourage interest from both project developers and residential and small commercial customers.

The legislature also tasked us with minimizing cost-shifting to non-participants. We recognize that the cost of initially funding and commencing the program as described in statute means that non-participating customers must bear some program costs. Based upon the analysis and information available to us and in order to successfully balance these interests and stand up the CSP, we determine that good cause exists to grant an exception to the use of resource value of solar. Therefore, we make the following decisions in an effort to balance incentive for customer participation, minimization of cost shifting, and the public interest.

A. Interim Capacity Tier, Bill Credit Rate, and Program Administrator Costs

1. Staff's Recommended Interim Capacity Tier

In their October 4, 2019 report, Staff recommended that the interim tier be set at 75 percent (~120 MW) of the program initial capacity tier (collectively ~160 MW) for PacifiCorp, dba Pacific Power, and Portland General Electric Company (PGE).[2] For Idaho Power, Staff recommended the interim tier to be set at 100 percent of the company's portion of the initial program capacity tier.

[2] OAR 860-088-0060(2) states: "The initial program capacity tier for each electric company is equal to 2.5 percent of the electric company's 2016 system peak." Staff noted the individual and collective interim program capacity tier for each electric company in Attachment D, page 66 in Table 1 (Oct. 4, 2019). The estimated collective amount of the initial program capacity tier is 161.02 MW. The interim tier is the portion of the initial program capacity tier to be launched using the current residential retail rate.

2. Staff's Recommendation for the Bill Credit Rate

Staff recommended that the bill credit rate be set at the current residential retail rate of each utility, with an annual escalator of 2.18 percent.

3. Staff's Recommendation for the Program Administrator Costs

Staff recommended that the general participant administrative fee, covering program administrator costs, be set at the level required to recover ongoing costs when 80 MW of the CSP are fully subscribed and billed. Staff recommended the fee to be $1.50 per kW per month.[3]

4. Commission Decision

As noted above, through this decision we endeavor to balance the commencement and maintenance of a viable program, while at the same time following the statutory directive to minimize cost-shifting to non-participants. The interim tier, bill credit rate and program administrator costs are elements that will collectively determine the availability and viability of projects, customer participation levels, and non-participant costs.

For the bill credit rate, we adopt the current residential retail rate of each utility, as provided in the Staff Report.[4] We decline to add an annual escalator to this cost. Staff proposed that the electric companies file an updated residential retail rate annually and that the updated rate will apply to projects receiving pre-certification in the following year[5] (as the sum value of the rates for residential basic service change), but for each project, participants receive the nominal value of the current retail rate at the time of pre-certification for the duration of the PPA between the project and the utility. Thus, the residential retail rate under which each project may commence will not be adjusted.[6]

The general participant administrative fee will be set at a level assuming full participation in the program's initial capacity tier (~160 MW). Staff estimates this charge, with currently available data, at $0.85 per kW per month for all utilities.

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[3] *Id*. at 31, Attachment A.
[4] *Id*. at 22.
[5] *Id*. at 81, Attachment D.
[6] *Id*.

The interim tier for PacifiCorp and PGE is set at 50 percent of the initial program capacity tier. We adopt an interim tier of 100 percent of the initial program capacity tier for Idaho Power.

We adopt Staff's bill crediting procedure mechanics,[7] with the following clarification: The annual true-up will be a netting of each CSP participant's kWh usage against the CSP project generation for which the participant was credited over the 12-month annual billing cycle. In addition, there will be a true-up of any additional bill credit value accrued to the community solar program participant. The value of excess kWh and other remaining bill credit value at the end of annual billing cycle will not roll over to be applied to the participant's next utility bill, and will be donated for use in low income programs of the electric company serving the participant. We expect Staff to further clarify this concept in the Program Implementation Manual (PIM), which is currently scheduled to be presented to the Commission on December 17, 2019.

B. Small Project Carve-out

We adopt Staff's recommendations regarding the small project carve-out, including extending the carve-out to include projects with non-profit and public entities as the project manager, with no modifications.

C. Low-income Program Elements

We adopt Staff's recommendations regarding the low-income CSP elements with no modifications.

We discussed whether flexibility regarding the 20 percent bill discount may be possible when a project aims to serve significantly more than the minimum percentage of low-income customers. We decided that this needed further consideration and the question will be deferred and addressed as a part of the PIM.

D. Waiver Request by Idaho Power

Idaho Power's individual comments requested "an exemption from the small project carve-out and/or project manager restrictions in order to allow a 3 MW CSP project to participate in Idaho Power's service territory."[8] In addition, Idaho Power indicated that the low-income bill savings percentage recommendations would hinder the proposed project within their Oregon service territory, as the project may obtain more than 10

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[7] *Id.* at 27

[8] Idaho Power Comments at 4 (Oct 15, 2019).

percent low-income customer participation. Therefore, the company requested flexibility with regard to the low-income bill savings requirements.

We acknowledge that, along with extending the interim tier to the full initial capacity tier to assist in the development of the project described in Idaho Power's comments, Idaho Power's requested waiver regarding the small project carve-out must also be granted in order to allow Idaho Power to address conditions unique to its participation in the CSP. Therefore, we therefore grant a waiver of the small project carve-out rules to Idaho Power along with extending the interim tier to 100 percent of Idaho Power's initial capacity. As noted above, the low-income flexibility request will be addressed when we consider the PIM.

E. Interconnection

We adopt Staff's recommendations covering the CSP interconnection process.

F. Annual Utility Communication with Regard to CSP offerings

We adopt Staff's recommendation that the utilities provide proof of at least one communication per year to all customers on eligible rate schedules that informs them of the CSP opportunity, directs customers to the list of available projects on the CSP program website, and provides the Program Administrator's contact information.

III. ORDER

IT IS ORDERED that Staff's recommendations as presented in the October 4, 2019 Staff Report attached as Appendix A be adopted, with following modifications:

1. The bill credit rate will be the residential retail rate of each utility without an annual escalator;

2. The interim tier for PacifiCorp and PGE is set at 50 percent of the initial program capacity tier, and for Idaho Power at 100 percent of the initial program capacity tier;

3. The general participant administrative fee will be calculated assuming full participation in the program at the initial program capacity tier;

4. A waiver of the small carve-out CSP rules is granted to Idaho Power.

Made, entered, and effective Nov 08 2019.

Megan W. Decker Chair	**Stephen M. Bloom** Commissioner
	Letha Tawney Commissioner

A party may request rehearing or reconsideration of this order under ORS 756.561. A request for rehearing or reconsideration must be filed with the Commission within 60 days of the date of service of this order. The request must comply with the requirements in OAR 860-001-0720. A copy of the request must also be served on each party to the proceedings as provided in OAR 860-001-0180(2). A party may appeal this order by filing a petition for review with the Circuit Court for Marion County in compliance with ORS 183.484.

ITEM NO. RA1

PUBLIC UTILITY COMMISSION OF OREGON
STAFF REPORT
PUBLIC MEETING DATE: October 22, 2019

REGULAR __X__ **CONSENT** ____ **EFFECTIVE DATE** __N/A__

DATE: October 4, 2019

TO: Public Utility Commission

FROM: Caroline Moore

THROUGH: Jason Eisdorfer and JP Batmale

SUBJECT: OREGON PUBLIC UTILITY COMMISSION STAFF:
(Docket No. UM 1930) Community Solar Program interconnection, low-income, transition to ongoing costs, and bill credit rate policies.

STAFF RECOMMENDATION:

The Oregon Public Utility Commission (OPUC or Commission) should approve OPUC Staff's (Staff) proposals for CSP interconnection, low-income requirements, transition to ongoing costs, and bill credit rate policy decisions, which are detailed in Attachment A.

DISCUSSION:

Issue

Whether the Commission should adopt Staff’s proposal to address major implementation policy issues related to interconnection, low-income requirements, transition to ongoing costs, and bill credit rate.

Applicable Law

ORS 757.386(2)(a) directs the Commission to establish a program that provides electric customers with the opportunity to share the costs and benefits of solar generation. Section (2)(b) directs the Commission to adopt rules that, at minimum:

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

On June 29, 2017, the Commission adopted formal rules for Oregon's Community Solar Program under Oregon Administrative Rules (OAR) Division 88 of Chapter 860.

Analysis

Background
When the Commission adopted administrative rules for the CSP, it recognized that certain program decisions would be best resolved later in the implementation process.[1] Staff began working with the Program Administrator (PA) and stakeholders to develop solutions for the majority of outstanding implementation decisions in the program implementation manual (PIM). However, several policy issues were identified to be significant and complex enough to warrant a separate Commission decision process.

These decisions are specific to four policy areas that represent critical inputs for Project Managers to prepare projects for pre-certification. Therefore, these decisions must be resolved prior to pre-certification launch, which is scheduled for December 16, 2019.[2]

The four policy issues addressed separately from the PIM include:

1. Interconnection: solutions to ensure that CSP interconnections are fair and functional
2. Bill credit:
    a. Implementation of the Simple Retail Rate
    b. Transition after the interim capacity tier
3. Low-income participation requirements:
    a. Minimum eligible low–income participants per project (%)
    b. Requirements for low–income subscriptions
    c. Definition of eligible low-income participant
4. Transition between start-up and ongoing costs:
    a. Transition point
    b. Administrative fee methodology[3]

On June 19, 2019, OPUC Staff released a draft policy proposal solely focused on CSP interconnection (See Attachment C). Following the proposal, Staff engaged stakeholders in three rounds of comments and two workshops on July 31, 2019, and August 26, 2019. At these workshops and in comments, stakeholders discussed the tradeoffs of Staff's initial proposal, along with a range new and modified measures that could provide more impactful, near-term solutions to CSP interconnection barriers. No

[1] Additional detail is provided in Attachments C and D.
[2] *See* Docket No. UM 1930, Staff's amended schedule, September 16, 2019.
[3] *See* Docket No. UM 1930, Staff's amended schedule, August 23, 2019.

final set of CSP interconnection policy recommendations were issued in a report. Rather, they are found in this public meeting memo.

On September 13, 2019, Staff released a different draft policy proposal that addressed the other three CSP policy areas: low-income requirements, transition to ongoing costs, and bill credit rate (See Attachment D). Staff released the draft policy proposal to allow additional time for stakeholders to develop comments prior to the Commission's consideration of Staff's final proposals.

This public meeting memo represents the culmination of several months of work, multiple rounds of stakeholder comments, and Staff's final recommendations for each of the four CSP policy areas. The remainder of this report captures Staff's final recommendations for each of the four policy issue areas. These recommendations are detailed in Attachment A. The remaining steps for this process are provided in Table 1 below.

Staff's draft policy proposal for CSP interconnection is in Attachment C. The draft proposal includes Staff's analysis of the barriers to CSP interconnections and a summary of Staff's initial draft interconnection proposal. Additional understanding of the barriers and potential solutions evolved over many meetings and rounds of comments. This memo summarizes these learnings and explains Staff's final recommendations for CSP interconnection

Attachment D provides detailed analysis supporting Staff's final recommendations for low-income requirements, the transition to ongoing costs, and the bill credit rate. Therefore, this memo briefly summarizes Staff's final recommendations and focuses on describing the components that are new or modified from Staff's initial draft proposals.

Table 1: Remaining Steps in Policy Decision Process	
Date	**Activity**
October 15, 2019	Deadline for stakeholder written comments on Staff report.
October 22, 2019	Regular Public Meeting: Staff presents final policy recommendations and stakeholders have the opportunity to comment.
October 29, 2019	Special Public Meeting: Commission deliberates and decides policy issues.

Interconnection final recommendation

Staff greatly appreciates parties' collaborative effort to identify a set of near-term solutions that can help ensure CSP interconnections are fair and functional, and to further develop the catalogue of interconnection measures that warrant consideration in longer-term venues.

Staff notes that there are several other dockets related to small generator interconnection and the efficient integration of distributed energy resources. On

March 13, 2019, the Commission opened Docket No. UM 2005 Investigation into Distribution System Planning.[4] On July 30, 2019, the Commission opened Docket No. UM 2032 Staff Investigation into Treatment of Network Upgrade Costs for QFs. When opening UM 2032, the Commission noted that,

> Following a prehearing conference and after considering recommendations from the parties, whether the scope of the investigation into the treatment of network upgrade costs for QFs should be expanded to include a limited number of additional, discrete issues related to interconnection of QFs.[5]

To the extent that Staff finds interconnection measures discussed during the CSP interconnection process better addressed in a broader or longer-term venue, Staff recommends that the measures are considered for inclusion in the scope of these or any subsequent interconnection related dockets.

A summary of interconnection barriers—updated based on discussion following Staff's initial proposal—and the measures identified in this process that could address these barriers are summarized in Figure 1. The remainder of this section briefly describes each interconnection measure identified, summarizes stakeholder feedback, and explains Staff's final recommendation in the context of the following decision-making criteria:

- Timing: Whether the solution can easily be implemented in the near-term.
- Impact: Whether the solution will have a broad and meaningful impact on CSP project interconnections.
- Ratepayer protection: Whether the solution minimizes impact on ratepayers.
- Other considerations: Any additional legal or practical considerations.

[4] Commission Order No. 19-104.
[5] Commission Order No. 19-254.

Figure 1 Summary of interconnection barriers and solutions

		Staff final recommendation #1: Simplified CSPs interconnection process if sited and sized to reduce likelihood of deliverability upgrades	**Staff final recommendation #2:** Begin developing models for cost-sharing between generators	**Staff final recommendation #3:** Simplified metering requirements for small projects	**Staff final recommendation #4 :** OPUC issue third-party reviewer RFI	**Staff final recommendation #5:** Enhanced pre-application report for community-driven projects	**Staff recommendation #6:** PacifiCorp to report on the process to address the backlog of interconnection applications.	PAC uses network transmission service to wheel the net output of projects to its load	25% cost envelope on upgrades	Additional timelines for utility interconnection process (studies and upgrades)	Registered PE Stamp on utility studies	Projects can use third party engineering studies	Allow CSPs under 2 MW to interconnect under the net metering interconnection rules	CSP policies must apply to all 3 MW projects
Assignment of **transmission** system (network) upgrades to small generators	NRIS requirement, studied and responsible for paying deliverability-related upgrade costs	●						●					●	
Assignment of **distribution** system costs to small generators	Upgrades tied to higher queued projects regardless of timeline or feasibility	●	●										●	
	No cost-sharing mechanism between projects		●											
	Difficult for small projects to bear cost of certain upgrades			●	●									
Lack of transparency/ control/certainty over costs	Interconnection backlogs and timing uncertainty	●					●			●			●	
	Difficult to verify the conclusions of the studies performed by the utility, suggest alternatives				●						●	●		
	Access to preemptive data for siting and sizing to avoid upgrades	●				●								
	Variation in upgrade cost estimates as study process becomes more rigorous and construction begins								●			●	●	
	Staff recommends consideration under:							UM 2032	UM 2032/ UM 2005	UM 2032/ UM 2005	UM 2032	UM 2032	N/A	N/A

Interconnection recommendation #1: Simplified CSP interconnection process
In its initial proposal, Staff identified the utility practice of requiring Network Resource Interconnection Service (NRIS) for small generators, and the associated transmission upgrades that can be assigned to the generator under this practice, as a major barrier to CSP interconnection in the state.[6] To help CSP generators overcome this, Staff initially proposed that utilities allow CSP generators to interconnect with Energy Resource Interconnection Service for a limited period of time and volume of projects. Under this proposal, generators would avoid being assigned deliverability-driven transmission system upgrade costs, and the utility would incur any deliverability costs associated with the project when its market function makes a transmission service on behalf of the generator. Staff recommended that this near-term CSP measure serve as a pilot program to understand whether this practice would place significant transmission upgrade costs on ratepayers. The results of this pilot would inform consideration of removing the NRIS requirement for all QFs.[7]

While the majority of stakeholders expressed support for this pilot, the Joint Utilities (Idaho Power Company "IPC", PacifiCorp "PAC", and Portland General Electric "PGE") raised a range of concerns and proposed a modification to this proposal.[8] First, the Joint Utilities expressed concern that Staff's initial proposal does not encourage efficient siting and sizing of projects and would expose ratepayers to too much risk of deliverability-driven upgrade costs.[9] Second, the Joint Utilities argued that CSP generators may not realize the benefits of this proposal when processing CSP interconnections applications in serial queue order.[10] Finally, the Joint Utilities assert that Staff's initial proposal would shift costs from the projects to retail ratepayers, which is contrary to the requirement in ORS 757.386(2)(b)(B) to minimize cost shifts and PURPA's customer indifference standard.[11]

To avoid these concerns, the utilities provided the following counter-proposal for a streamlined CSP interconnection process: Process and study eligible CSP projects separately from the traditional serial queue, considering a limited universe of electrically relevant generators located within the local area, and limited to scope of a FERC ERIS study.[12] The utilities proposed to define the local area to include, "the distribution circuit, substation transformer, and subtransmission line associated with the proposed CSP

[6] *See* Docket UM 1930, Staff's Draft Proposal for Community Solar Interconnection, June 19, 2019, p. 9.
[7] *Ibid*, p. 13.
[8] The following parties submitted written comments in support of this proposal (some with caveats discussed in the report): Sunthurst Energy, LLC, Pine Gate Renewables, Renewable Northwest Project, QF Trade Association (NIPCC, CREA, REC), and Oregon Solar Energy Industries Association/Coalition for Community Solar Access (OSEIA/CCSA). Bonneville Environmental Foundation, Spark Northwest, and the City of Portland did not address this proposal in their comments.
[9] *See* Docket UM 1930, Joint Utilities' Comments on Staff's Draft Proposal for Community Solar Interconnection, July 24, 2019, p. 4.
[10] *Ibid*, p. 40.
[11] *Ibid*, pp. 23- 24.
[12] *See* Docket UM 1930, Joint Utilities' CSP Interconnection Proposal, August 16, 2019, p. 1.

feeder."[13] Further, the Joint Utilities proposed to limit eligibility for this CSP interconnection process to projects sited and sized to minimize the likelihood that the project will trigger deliverability costs when the utility makes the transmission service request on behalf of the generator. The Joint Utilities proposed that CSP generators are eligible for the streamlined process if the proposed generator, together with all other interconnected and requested generation in the local area, is less than:

- For PGE and PacifiCorp, less than 25 percent of the peak load.
- For Idaho Power, less than 50 percent of the associated minimum load.[14]

The Joint Utilities clarified that the feeder loading data currently posted on OASIS represents a helpful snapshot for generators to site and size the project, but the utilities will individually assess eligibility under these thresholds separately for each generator.[15]

Finally, the Joint Utilities offered the following additional elements to the proposal:

- Generators must attest to being a CSP project to qualify and will lose CSP queue position if it does not qualify for the CSP or withdraws.[16]
- Generators with an existing interconnection queue position will have an opportunity to apply for the CSP queue prior to generators that do not already have an interconnection queue position. Projects with an existing interconnection queue position will be considered in the CSP queue in order of the previous queue position. Any new CSP interconnection requests will be assigned subsequent CSP queue positions in order of request.[17]
- While discussed in the workshops, the utilities state that further evaluation and technical consideration are required to assess whether the inclusion of storage or transfer trip equipment should be used as alternative eligibility criteria for generators that do not pass the feeder loading screens mentioned above.[18]

Recommendation: Staff recommends that the Commission adopt the Joint Utilities' proposal for a streamlined CSP interconnection process, with modifications.

[13] *Ibid*, p. 2.
[14] Id.
[15] *See* Docket UM 1930, Joint Utilities' Reply Comments, September 13, 2019, p. 6.
[16] *See* Docket UM 1930, Joint Utilities' CSP Interconnection Proposal, August 16, 2019, p. 4.
[17] *See* Docket UM 1930, Joint Utilities' Reply Comments, September 13, 2019, p. 8.
[18] *See* Docket UM 1930, Joint Utilities' CSP Interconnection Proposal, August 16, 2019, p. 4.

Staff finds that the streamlined CSP process meets Staff's proposed decision-making criteria, and that the proposal is improved by Staff's recommended modifications described below.

- Timing: The utilities note that this process can be implemented in the near term.[19] Removing CSP generators from serial queue will also improve the speed at which CSP generators move through the interconnection process.
- Impact: This proposal could apply to all CSP generators and addresses multiple barriers, including serial queue issues and deliverability-driven network upgrades. The eligibility criteria will also help reduce the likelihood of distribution system upgrades.
- Ratepayer protection: There is a risk that the CSP interconnection process will drive additional deliverability-driven ratepayer costs. The eligibility criteria is designed to minimize this likelihood.
- Other considerations: The Commission opened Docket No. UM 2032 because the issue of QFs and network upgrades could benefit from a more thorough development of a factual record. The data collected under the CSP interconnection process may help assess risks to ratepayers.

Staff recommends the following modifications to the joint utility proposal:

1. Eligibility criteria: Generators should be eligible for the CSP interconnection process if the proposed generator, together with all other interconnected and requested generation in the local area, is less than 100 percent of minimum daytime load (MDL). If a measure of MDL is not available for the feeder, utilities should use 30 percent of summer peak load.[20,21] This recommendation is supported by comments submitted by Bonneville Environmental Foundation and OSEIA/CCSA.

[19] *See* Docket UM 1930, Joint Utilities' Reply Comments, September 13, 2019, p. 3.
[20] Staff notes that work to finalize a method to calculate MDL remains underway per Commission Order No. 19-217. The Interconnection Data Workgroup, established under UM 2001 and continued under UM 2000, is addressing the "daytime minimum load" calculation at its October 9, 2019 meeting. Utilities will bring proposals for methodology for the cases where SCADA/hourly data is, and is not, available. Additionally, the utilities will address the potential of posting daytime minimum loads that have been calculated (data scrubbed, other factors considered) in interconnection study reports. The schedule for implementing the posting of MDL data will be established at the October 9, 2019 meeting.
[21] As noted in OSEIA/CCSA's Supplemental Interconnection Comments submitted September 13, 2019, National Renewable Energy Laboratories found that 71 percent of the comparative ratios of minimum daytime load to peak load were 30 percent and above for 500 residential and commercial feeders in a southwest U.S. city. Staff recognizes the difficulty of creating a standard proxy and considers this an additional reason for the utilities to identify an MDL methodology as soon as possible.

This screening criteria is not used to determine upgrades for reliability or safety. Rather, it is intended to limit the likelihood that the generator will trigger transmission upgrades to be borne by ratepayers. Staff finds that it is reasonable to use a more inclusive screening criteria within this limited environment. Not only will this broaden the impact that this near-term measure has on CSP generators (see Table 2), it will provide better data to assess the risks of changing the treatment of QFs as NRIS within other dockets, such as Docket No. UM 2032.

- In addition, Staff recommends that the utility consider the ratio of load to generation for all feeders leaving the substation serving the feeder on which the CSP generator proposes to locate. Staff finds that this will provide a more accurate assessment of the risk of backflow to the transmission system and will generate more valuable data for assessment of deliverability requirements for small generators.

- Finally, Staff encourages the utilities to continue to refine the screening criteria to account for differences between feeders. For example, a single threshold may overlook the difference in coincidence of load and generation on a heavily residential feeder versus a heavily industrial feeder. In addition, Staff encourages the utilities to consider storage and transfer trip as eligibility criteria, but does not want that process to interfere with the timely implementation of the CSP interconnection process.

Table 2 Estimated number of feeders where CSP generators of various sizes are eligible for the CSP interconnection process
Based on UM 2001 data posted to OASIS August 30, 2019

		IPC		PAC		PGE	
		50% MDL	100% MDL	25% Peak Load	30% Peak Load	25% Peak Load	30% Peak Load
25kW	# feeders	38	43	385	386	515	517
	%feeders	62%	70%	76%	77%	96%	96%
1 MW	# feeders	1	8	255	287	411	444
	% feeders	2%	13%	51%	57%	77%	83%
2 MW	# feeders	0	1	54	115	172	271
	% feeders	0%	2%	11%	23%	32%	51%
3 MW	# feeders	0	0	3	15	15	64
	% feeders	0%	0%	1%	3%	3%	12%

Note: Many factors determine project siting; some feeders identified in this table may be inaccessible for other reasons, such as the availability of land. On the other hand, additional feeders may have capacity that cannot be determined due to redactions within the publicly available feeder data. Redacted feeders may indicate favorable locations due to the likelihood of industrial and large commercial load.

2. Tracking and reporting: Staff finds that it is critical that the CSP interconnection process generate data for use in the broader interconnection-related efforts. Staff expects that this process will not only generate useful data to support Docket No. UM 2032, it could help generate learnings for Docket No. UM 2005, such as where greater visibility on the distribution system would be most valuable. To accomplish this, Staff recommends the utilities be required to submit the following to the Commission:
   - List of generators deemed eligible for the CSP interconnection process:
     - A copy of each interconnection study performed for each generator.
     - The cost of upgrades required for each generator, including the original cost estimate and the final cost. This includes transmission system upgrades assigned the generator, distribution system upgrades and interconnection facilities assigned to the generator, and any upgrades borne by the utility (presumably as a result of the transmission service request).
     - The following dates: application received, when each study was provided to generator, when each agreement was provided to generator, when each agreement was signed by generator, the completion of all upgrades, the date that the generator was energized.
   - List of generators deemed ineligible for the CSP interconnection process:
     - Any studies performed for the determination of ineligibility.
     - The following dates: application received, when each study was provided to generator, when each agreement was provided to generator, when each agreement was signed by generator.
   - After 6 months, Staff will work with utilities to provide an interim report on key learnings. Staff will also work with utilities to gather additional data as needed by other related investigations.
   - After 12 months, Staff will recommend to Commission whether to conclude or continue.

Interconnection recommendation #2: Begin developing models for cost-sharing between generators

Staff's initial proposal also included distribution upgrade cost-sharing between CSP generators. Staff proposed that, similar to a line-extension, utilities facilitate a process whereby a CSP generator responsible for a common distribution system upgrade is reimbursed by any subsequent generators utilizing the upgrade. While stakeholders expressed general support for this as a near-term proposal, Staff received the following feedback:

- Cost-sharing may be too complicated to implement in the near term.

- Staff's proposal does not alleviate the need for the first generator to bear the full cost of the upgrade or provide certainty that subsequent generators will request interconnection in the local area.
- Cost-sharing is more effective if expanded to non-CSP generators.

In addition, multiple parties recommended modifying Staff's initial proposal:

- OSEIA/CCSA suggested at the July 31, 2019 workshop that preemptive cost-sharing would have a greater impact on CSP generators. Citing pilots underway in other jurisdictions, comments submitted by Charlie Coggeshall proposed that the utilities proactively identify areas to make common system upgrades, and charge subsequent generators that utilize the upgrades a pro-rated fee as part of its interconnection upgrade costs.[22] Stakeholder discussion highlighted that there are many ways to approach preemptive cost sharing that place varying levels of stranded asset risks on ratepayers. The QF Trade Association expressed support for the preemptive cost-sharing proposal.[23]
- Spark Northwest proposed a similar preemptive strategy that extends beyond cost-sharing for system upgrades. Through Community Energy Zones (CEZs), the utilities would implement a streamlined and simplified interconnection process on areas of the system that have excess interconnection capacity or would otherwise benefit from increased distributed energy resources. Spark Northwest added that these zones could be "negative lists" of areas where distributed energy resources would incur significant upgrade costs.
- The Joint Utilities expressed willingness to study two projects jointly to facilitate cost sharing, provided that the projects must be located near each other and enter the CSP interconnection queue at the same time.[24]
- The Joint Utilities do not support a requirement that the utilities administer cost-sharing. The utility role should be limited to providing data and it should be CSP generators or the PA that facilitate the cost-sharing.[25]

<u>Recommendation</u>: Staff recommends that the Commission begin developing models for cost-sharing between generators.

[22] *See* Docket UM 1930, Distribution System Upgrade Cost Sharing Memo, filed by Charlie Coggeshall, August 19, 2019, and Solar Parties Supplemental Interconnection Comments, September 13, 2019, p. 2.
[23] See Docket UM 1930, Comments of the Northwest and Intermountain Power Producers Coalition, The Renewable Energy Coalition, and the Community Renewable Energy Association On PacifiCorp Interconnections, September 13, 2019, p. 2.
[24] *See* Docket UM 1930, Joint Utilities' CSP Interconnection Proposal, August 16, 2019, p. 3.
[25] Id*.*

While the near-term feasibility and impact of implementing cost-sharing measures may be limited, Staff finds the concept intriguing; likely to reduce barriers to the efficient integration of distributed energy resources; and possible to implement without impacting ratepayers:

- Timing: Implementing a utility-facilitated or preemptive cost-sharing process requires additional work with stakeholders. It is possible for CSP generators to negotiate cost-sharing amongst themselves in the near term.
- Impact: While stakeholders confirmed that Staff's proposal would be somewhat helpful, and preemptive cost-sharing would be even more helpful, the opportunity for project-to-project cost sharing may be limited by the streamlined CSP interconnection process. In other words, the eligibility criteria may limit the number of feeders that can accommodate multiple CSP interconnections.
- Ratepayer protection: The cost-sharing proposals discussed with stakeholders are designed such that generators are responsible for the cost of distribution system upgrades. However, approaches in which utilities front the cost of upgrades carry risks of stranded ratepayer investments.
- Other considerations: Limiting the scope to CSP generators may limit the value of cost-sharing. Therefore, more detailed discussions of cost-sharing pilots should involve broader stakeholder groups.

To account for these trade-offs, Staff recommends two measures. In the near-term, Staff recommends a few steps to help enable generators to voluntarily engage in cost-sharing:

1. Direct the utilities to study CSP generators jointly upon request if the generators are located in the same local area and apply for interconnection at the same time.
2. Direct the PA to work with the utilities to compile system data, information collected through Project Manager registration and pre-certification, and CSP interconnection application information by geographic area. The PA can host this information on the CSP website along with any additional training materials required.

In 2020, Staff will engage stakeholders interested in small generator interconnection, such as those participating in Docket Nos. UM 1930, UM 2032, and UM 2005. Staff will initiate a process to continue discussion of preemptive cost sharing and CEZs. In the meantime, Staff is open to the utilities submitting pilot proposals for preemptive cost sharing if there is interest to initiate the process sooner.

These discussions should be framed with an expectation that generators remain responsible for all upgrades required to safely interconnect (not ratepayers), ratepayers are protected from the risk of stranded upgrades, and equity is a consideration of any site selection process.

Interconnection recommendation #3: Simplified metering for small projects
The stakeholder process included discussion of the additional barriers that small projects face when interconnecting in front of the meter. Bonneville Environmental Foundation raised a specific challenge related to the requirement to meter even very small CSP generators at primary voltage.[26] In response, the Joint Utilities proposed to meter a CSP project that is 360 kW or less on the low side of the transformer, and to account for conversion losses and the project's output.[27]

Recommendation: Staff recommends that the Commission adopt the Joint Utility proposal to allow CSP generators 360 kW or less to meter on the low side of the transformer.

This proposal did not receive negative feedback and was supported by Bonneville Environmental Foundation and OSEIA/CCSA in comments submitted individually to Docket No. UM 1930 on September 13, 2019.

- Timing: Can be implemented without significant process, but does require utilities and generators to agree on a methodology to account for losses on the high side of the transformer.
- Impact: Can significantly reduce upgrade costs for small CSP generators, but not applicable to larger generators.
- Ratepayer protection: Only risk to ratepayers is if the methodology to account for losses is not sound.
- Other consideration: Staff is concerned that additional opportunities to enable efficient integration of small generators are not being considered as collaboratively (see interconnection recommendation #4)

Staff proposes that the utilities to work with generators agree upon a methodology to account for transformer losses.

In addition Staff should work with parties to continue to explore avenues for CSP generators and utilities to collaboratively consider additional one-off interconnection

[26] *See* Docket UM 1930, Bonneville Environmental Foundation's comments on the draft Community Solar Interconnection proposal, July 24, 2019, p. 1.
[27] *See* Docket UM 1930, Joint Utilities' CSP Interconnection Proposal, August 16, 2019, p.4.

enhancements. This work should be coordinated with Staff's recommendation #4 and the scoping of Docket No. UM 2032.

Interconnection recommendation #4: Issue a Request for Information (RFI) for third-party expert interconnection study review services.

Staff's initial proposal mentioned access to a third-party expert reviewer as a potential tool for generators to use in verifying the conclusions of the interconnection studies performed by the utility. This can also provide a more robust avenue to suggest additional measures to enable the efficient integration of small generators. Stakeholders in the CSP interconnection process affirmed that verifying the conclusions in interconnection studies as a concern. For example, OSEIA/CCSA states in comments submitted to Docket No. UM 1930 on
July 25, 2019:

> The Solar Parties is concerned that some distribution cost upgrades being required by utilities are unnecessary and/or overpriced. For example, industry members state that PAC has required microwave telemetry at a price of $1.4 million for a 3 MW project, while PGE has required expensive fiber to be used for all protective relays when radio and microwaves work just as well. As it stands, utilities are not incented to drive down the cost of these upgrades.[28]

Spark Northwest also suggests that the Commission adopt a third-party review process in its July 24, 2019 comments, and the City of Portland mentioned that "It will be very difficult for smaller projects, which have fewer financial resources available, to make it through this process."[29] The potential value of third-party study review was further discussed at the August 26, 2019 interconnection workshop.

<u>Recommendation</u>: *Staff recommends that the Commission continue to explore third-party review as an intermediate measure, beginning with the release of a Request for Information (RFI) for third-party expert interconnection study review services.*

While Staff applauds parties' collaborative work to address certain technical issues raised in the CSP interconnection process, Staff finds that several additional one-off issues could benefit from the same consideration. For example, issues related to

[28] *See* Docket UM 1930, Solar Parties Comments in response to: PUC Staff Draft Proposal for Community Solar Interconnection, July 24, 2019, p. 3.

[29] *See* Docket UM 1930, Spark Northwest's comments on the draft Community Solar Interconnection proposal, July 24, 2019, p. 2, and City of Portland's comments on the draft Community Solar Interconnection proposal, July 24, 2019, p.2.

telemetry requirements for small generators, consideration for the properties of smart inverters, and the use of storage or transfer trip technology to minimize deliverability and other system upgrades. Given the opportunity that CSP creates for less sophisticated entities to participate in solar generation, Staff expects that these concerns may not be exhaustive of those that will emerge through CSP interconnections. Further, Staff finds that third-party review could generate data to support longer-term efforts under Dockets No. UM 2032 and UM 2005. Therefore, Staff recommends that a third-party reviewer could have a meaningful impact on CSP interconnections. However, evaluating the timing and ratepayer impact require additional data.

- Timing: Staff did not initially include this measure in the initial draft proposal due to concerns that it was not possible to implement by the end of the year, informed by its experience contracting for PA services. OSEIA/CCSA expanded upon timing concerns stating that a review process could delay the timeline for projects to complete the interconnection process.
- Impact: Staff expects access to a third-party reviewer will benefit CSP generators, but additional analysis is required to understand the cost and determine if the cost justifies the benefits.
- Ratepayer protection: Staff finds that more analysis and a better understanding of third-party costs is required to understand whether the benefits of third-party review will exceed the costs, and whether the costs can be borne by CSP Project Managers or ratepayers.

Given the trade-offs described above, Staff recommends, as a near term action, that the OPUC issue an RFI for a qualified electrical systems engineering expert to review utility interconnection studies for CSP generators upon request.

Interconnection recommendation #5: Enhanced pre-application report for non-profit and public Project Managers

At the July 31, 2019 CSP interconnection workshop, participants noted that the utility pre-application report process was burdensome to less sophisticated Project Managers that cannot afford the trial and error process of submitting multiple pre-application report requests to identify a suitable project site. In response, the Joint Utilities proposed an enhanced pre-application process available on a pilot basis for CSP generators. Generators with a non-profit or public entity as the Project Manager, can request pre-application reports for up to five separate sites in a single request, with the fee waived. The utilities require that generators sign an attestation that the proposal is for a non-profit or public entity managed CSP. In addition, the Joint Utilities agree to publicly post on OASIS any pre-application reports.[30]

> *Recommendation: Staff recommends that the Commission adopt the Joint Utility proposal to provide enhanced pre-application reports to non-profit and public entities serving as Project Managers.*
>
> This proposal did not receive negative feedback and was supported by Bonneville Environmental Foundation and OSEIA/CCSA in comments submitted individually to Docket No. UM 1930 on September 13, 2019.
>
> - Timing: Can be implemented in the near-term.
> - Impact: Is a valuable step in helping less resourced CSP Project Managers control interconnection costs. While the distribution system data provided under UM 2001 is meaningful, stakeholders noted that additional proactive siting information, such as maps indicating good or bad interconnection locations, would be even more helpful.
> - Ratepayer protection: Staff is unclear about the extent to which ratepayers will incur costs to support the enhanced pre-application reports.
>
> In addition, parties in Docket Nos. UM 2032 and/or UM 2005 should continue to refine the publicly available distribution system information to support more proactive siting assistance, such as maps.

Interconnection recommendation #6: Direct PacifiCorp to provide additional information on the process to address the backlog of interconnection applications.

Staff's initial proposal characterized the backlog PAC faces in processing applications in its standard interconnection queue (See Attachment C). Staff finds that the backlog issues have not yet been resolved. While Staff recommends a streamlined CSP interconnection process, it is still important to provide certainty and support for CSP generators interconnecting outside of this process. Therefore, Staff recommends that the Commission require PAC to report the following information to the Commission by December 2, 2019:

- For all Oregon small generators that have applied for interconnection but not yet received a study agreement:
    - The status of providing the agreement or study.
    - The date on which PAC will provide the study results.

[30] *See* Docket UM 1930, Joint Utilities' CSP Interconnection Proposal, August 16, 2019, p.5.

- For all Oregon small generators that have executed a study agreement and not yet received the study:
    - The status of providing the agreement or study.
    - The date on which PAC will provide the study results.

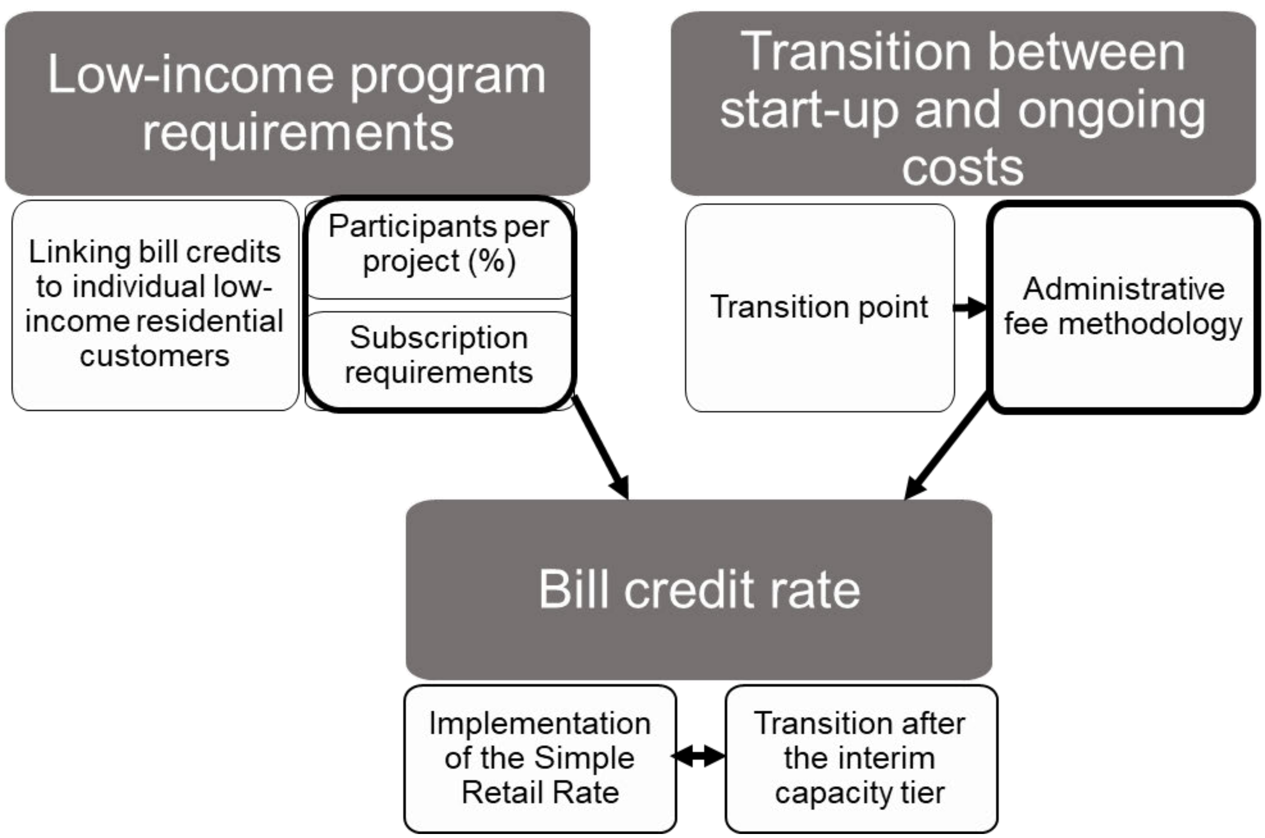
Interconnection measures proposed, but not recommended for CSP.
Staff appreciates stakeholders' efforts to identify the additional CSP interconnection measures that Staff has not included in its final interconnection recommendations. Many of these concepts are promising opportunities to promote the efficient integration of distributed energy resources. However, Staff finds that these measures do not present the best balance of timing and impact given parties' limited resources in the near-term. The table below summarizes Staff's assessment of these measures and recommended avenues for further consideration.

Table 3: Additional interconnection measures raised by parties		
Barrier	Proposed solution	Staff analysis
Transmission (network) upgrades	PAC uses network transmission service to wheel the net output of projects to its load	Not designed to impact a broad range of CSP projects, already raised in Docket No. UM 1610 and under consideration in UM 2032.
Lack of transparency/ control/ certainty over costs	Cost envelop: CSP generators not obligated to pay for upgrade costs 25% above initial studies	Risk of providing perverse incentives to increase cost estimates or drive lengthier interconnection process due to more robust studies behind the initial estimate. Risk that ratepayers may bear the cost of generators' upgrades. Staff finds the proposal intriguing, but additional process is required to consider an approach that overcomes the potential for these negative outcomes. Parties should consider for inclusion in the scope of Docket Nos. UM 2032 and/or UM 2005.
	Establish additional timelines for utility interconnection process	Staff hopes that the streamlined CSP interconnection process will alleviate much of the concern about timelines. Further, the state's Small Generator Interconnection Procedures already require inclusion of a reasonable schedule in each interconnection study agreement, and that the utility make reasonable, good-faith efforts to follow the schedule. Additional analysis of the utilities' implementation of these rules is not feasible in the near-term. However, the data gathered through interconnection recommendation #1 and interconnection recommendation #4 can support consideration of additional measures if included in the scope of Docket Nos. UM 2032 and/or UM 2005.
	Professional Engineer stamp required on studies	Does not directly minimize CSP interconnection barriers. Already raised in Docket No. UM 2000 and could be scoped in Docket No. UM 2032.
	Projects can use third party engineering studies	Not directly targeted at reducing barriers or timelines for CSP interconnections. Staff recommendation #4 may be more accessible for CSP generators. Already raised in Docket No. UM 2000 and could be scoped in Docket No. UM 2032.
N/A	CSP interconnection policies must apply to all QFs or all 3 MW small generators	Beyond the scope of this proceeding. Sufficient reason to limit streamlined CSP interconnection to CSP projects.
Transmission (network) upgrades, distribution upgrades, lack of transparency /control/ certainty over costs	Stakeholders proposed that CSP projects could interconnect under Division 39 net metering rules to reduce barriers.	As indicated in the Joint Utility's comments submitted on September 13, 2019, "CSP QFs have been deemed by the state to be participating in a net metering-type program." Parties may have suggested this measure under the assumption that it would reduce the need for a system impact study or facilities study or avoid any distribution system upgrades that are required for safety or reliability. Staff does not find that to be true. However, Staff believes that adding CSP generators up to 3 MW to OAR 860-039-0010, would allow generators to be studied outside of serial queue order, considering a limited set of electrically relevant projects, without deliverability-driven network upgrades, and reduce the likelihood of distribution system upgrades. Staff would be supportive of this measure if 1) eligibility is limited to CSP generators that, together with all other interconnected and requested generation in the local area, have a capacity less than 100 percent of minimum daytime load (MDL) or 30 percent of summer peak load, and 2) CSP generators were required to be studied for a Tier 3 interconnection. However, this proposal is unnecessary because the benefits are accomplished by the Joint Utility's proposal captured under Staff's interconnection recommendation #1.

Low-income, transition to ongoing costs, and bill credit rate recommendations
On September 13, 2019, Staff released a preview of its proposal for key policy decisions related to low-income requirements, the transition to ongoing costs, and the CSP bill credit rate. In its proposal, Staff maintained that certain policy recommendations related to low-income requirements and the transition between start-up and ongoing costs are required inputs into Staff's bill credit rate analysis, as illustrated in Figure 2. Therefore, Staff's proposal provided recommendations for all three policy areas together.

This section briefly summarizes the decision-making criteria, the resulting recommendations, and notes two areas where Staff refined its recommendation from the draft policy proposal due to additional information and analysis.

Figure 2 Summary of Policy Issues and Interactions Addressed in Staff's Proposal



Staff identified the following decision-making principles to guide its recommendations for key policy issues.

Overarching purpose – **equitable opportunity**: Staff proposes that the overarching objective of the CSP is to establish an equitable opportunity for consumers that have not been able to access customer generation opportunities and incentives.

Additional requirements: As a complement to the overarching purpose, Staffs finds that the CSP must balance the following additional requirements:

- Low-income accessibility: Staff proposes a minimum expectation that low-income CSP participation makes low-income participants better off. This means the net impact of participation cannot result in an increase of low-income participant bills both month-over-month and over the life of a CSP subscription.
- Project availability: In addition, Staff identified minimum conditions for CSP project development to ensure that consumers will have access to opportunities to participate. These include:
  - Project Manager value: A minimum financial return is required for Project Managers to move forward with project development.
  - Project Manager certainty: Project Managers, at minimum, need to have a reasonable understanding of the administrative fees a project will incur, as well as the bill credit rate that the PA will assign to the project. This includes both the rate that will be assigned at pre-certification based on pre-certification queue position and the rate that participants will receive over the life of the project.
  - Community-driven project certainty: Community-driven projects may need additional certainty about the availability of capacity beyond the initial tier and the bill credit rate assigned to that capacity.
- Ratepayer value: Ratepayers need the lowest cumulative ratepayer impact at which the other program requirements are achieved.

Based on these principles, Staff recommended the following low-income requirements and an approach to the transition to ongoing costs (See Attachment D for additional detail):

- Adopt the following low-income policies by order and in the PIM, as detailed in the September 13, 2019 draft policy proposal:
  - Require a minimum of 10 percent of each CSP project's capacity to be allocated for use by qualifying low-income residential customers.
  - Require a 20 percent subscription discount for qualifying low-income subscriptions.
  - Define a qualifying low-income residential customer as:
    - A residential Idaho Power Company (IPC), PacifiCorp (PAC), or Portland General Electric (PGE) customer that meets the income and all other requirements set forth in the PIM.

    - A residential utility account holder with a utility allowance or other requirements of rent-assisted housing.
    - An affordable housing provider that directly pays for the electricity costs of residential tenants with household incomes that meet the income requirements set forth in the PIM and additional conditions for direct tenant benefits.
- Adopt the following transition to ongoing costs by order, as detailed in the September 13, 2019 draft policy proposal:
  - Limit start-up costs to specific program development activities.
  - Establish ongoing administrative fees for participants and pre-certification applicants at the level required to recover ongoing costs when 80 MW of CSP capacity are subscribed and billing, referred to as the "capacity transition level". This decision is driven by the bill credit analysis provided in the next section.

Table 4: Proposed Tentative Initial Administrative Fee Schedule				
Approx. MW subscribed and billing across utilities	% Capacity Tier (for context)	General Participant Admin Fee ($/kW/mo)	LI participant fee	Pre-certification Application fee ($/kW)
40.3	25%	$2.46	$0	$100*
80.5	50%	$1.50	$0	$75
120.8	75%	$1.00	$0	$50
161.0	100%	$0.85	$0	$40

*Adjusted to recover administrative fees not recovered under the $2.46/kw/month general participant administrative fee cap set forth in the contract for PA services.

  - Before 80 MW of CSP capacity is subscribed and billing:
    - Collect the full administrative fee from participants.
    - Collect $5/kW pre-certification application fee from Project Managers.
    - Backfill unfunded administrative costs with ratepayer funds until 80 MW is subscribed and billing.
  - Once 80 MW of CSP capacity is subscribed and billing:
    - Continue to collect the full administrative fee from participants.
    - Collect the full pre-certification application fee from Project Managers.
  - Pause pre-certification to determine the appropriate next steps if the program has not reached the 80 MW subscribed and billing 24 months following pre-certification launch.

Bill credit rate recommendations
The bill credit rate that CSP participants receive has been the subject of lengthy discussion throughout the multi-year CSP implementation process. As described in greater detail in Staff's draft policy proposal, the Commission established the Simple Retail Rate (based on the residential retail rate) as an interim bill credit rate for the first 25 percent of the capacity tier in 2018 and noted that,

> Staff working with stakeholders should review transition [to RVOS] options for consideration at a later date, and should keep us informed of important transition questions and issues as they emerge.[31]

As the CSP approaches pre-certification launch, Staff presents it continued learnings and analysis regarding the implementation of the above Commission direction regarding the bill credit rate. Under the overarching purpose of equitable opportunity, and recognizing the need to ensure project availability at the lowest ratepayer impact, Staff provides a final recommendation on the two outstanding bill credit rate questions:

- What is the specific value of the Simple Retail Rate (hereinto referred to as the "interim rate") for the first 25 percent of the program capacity tier (hereinto referred to as the "interim tier")?
- Can the CSP transitions to a rate based on RVOS after the interim tier?

In its draft proposal, Staff proposed to examine the following options for the specific value of the interim rate:

1. Fixed: Participants in the project receive the nominal value of the current retail rate at the time of pre-certification for the duration of the PPA between the project and the utility.
2. Floating: Participants receive the contemporary retail rate over the life of the PPA between the project and the utility, which will change when the residential retail rate changes.

In addition, Staff identified the following values for the current residential retail rate, based on the sum value of the rates for residential basic service. These values include transmission charges, distribution charges, the first 1,000 kWh energy charges, and system usage charges, but do not include any additional adjustments.

- IPC: $0.0848/kWh
- PAC: $0.0977/kWh
- PGE: $0.11234/kWh[32]

[31] *Ibid*, p. 4.
[32] See Attachment D, p. 22.

With respect to the floating rate, Staff initially proposed that,

> The floating rate is estimated as a fixed escalator, rather than an actual real time adjustment over the life of the project. This benefits the modeling in this report and upholds the project managers' and participants' need for certainty.
>
> A look at recent trends in residential rates across the three utilities indicates that 2% annual increase is the appropriate proxy for residential rate increases. Staff suggests that the same proxy rate escalator be applied consistently across utilities for administrative and consumer consistency.[33]

However, Staff has since determined that a modification is necessary. If the Commission adopts an interim bill credit rate composed of the current residential retail rate and a fixed annual escalator, the escalator should be obtained from an objective source, and not be deterministic or based on conjecture over future retail rates. Staff also recommends the escalator is based on a usual and customary reference for ratemaking. Therefore, Staff recommends that the escalator is derived from the latest Oregon Economic and Revenue Forecast's consumer price index (CPI) for Urban Consumers.[34] This is the resource that Staff recommends for use in general rate cases. Staff's proposal for the escalator is 2.18 percent. See Table 5 below for further detail behind this figure. Staff invites Stakeholder feedback on this proposal.

[33] Id.
[34] Oregon Economic and Revenue Forecast, Prepared by the Department of Administrative Services Office of Economic Analysis, August 28, 2019 p. 42.

Table 5: Staff recommendation for the interim bill credit rate fixed escalator	
Year	CPI
2019	1.90%
2020	2.20%
2021	2.20%
2022	2.20%
2023	2.20%
2024	2.20%
2025	2.20%
2026	2.20%
2027	2.20%
2028	2.30%
Arithmetic average of the forward data available	2.18%

Staff notes that the available alternative to this fixed escalator is updating all participants' bill credit rate annually to reflect the actual contemporary retail rate ("floating retail rate"). While this may help align the CSP opportunity with net metering and ensure the bill credit is never higher than retail rates, it would limit the ability to control ratepayer impacts if retail rates increase faster than the escalator. It would also complicate project financing, subscription pricing, and the ability of consumers to make informed choices about participation.

Because the fixed escalator remains similar to the 2 percent previously modeled, Staff has not modified the bill credit analysis presented in the draft policy proposal. In other words, the bill credit model still assumes a two percent fixed annual escalator (See Table 6). The only change is that the "floating retail rate" is now referred to as "retail + escalator."

Bill credit model

Staff evaluated the two bill credit questions by modeling the risks to ratepayer impact, and the risks to project availability associated with each option (fixed or escalated). This modeling estimated the total 20-year ratepayer impact and estimated an average project's IRR when, 1) the bill credit rate is transitioned to the latest RVOS values filed by the utilities, and 2) the two interim bill credit rate options are extended in 25 percent increments of the capacity tier. Staff and the PA sought to model an average project based on industry experience and insights into five CSP developers' pro formas (national and community-based organizations). A detailed summary of the modeling inputs are provided in Attachment B. However, Staff highlights the following considerations for this analysis:

- These modeling outcomes are intended to capture risks associated with different policy decisions. Staff's ultimate goal with this analysis is to identify the combination of policy choices that can feasibly stand up a successful program at the lowest cost possible, while ensuring that low-income participants are not harmed. This approach is driven by the Staff principles described above and the direction from the legislature to incentivize consumers of electricity to be owners or subscribers, while minimizing the shifting of costs from the program to ratepayers.

- The assumptions included are informed by developer-provided insights, but Staff worked with the PA, including Energy Trust of Oregon, to vet the developer insights and develop assumptions about an average project.
- The assumptions in this model are considered imperfect, and actual project characteristics are subject to a high level of variation across actual CSP projects.

Staff provides one additional clarification on the project availability metric. Staff used an 8 percent IRR as a proxy for the likelihood that there will be projects developed. As Staff explains its draft policy proposal, this metric is used to characterize the risks associated with the various policy decisions presented in this analysis. It is not intended as a minimum requirement for project development or absolute indicator that a given project will or will not move forward with development.

Staff cannot disclose the propriety analysis provided by developers. However, Staff can provide the following additional support for its assumption in its modeling that an 8 percent IRR reflects a reasonable likelihood that some amount of CSP projects will come online: In its discussion with developers, Staff and the PA found that developers used a range of target IRRs to determine whether to move forward with project development. One developer's target IRR was below 8 percent and the other four were above 8 percent. Staff and the PA chose a lower, more conservative target of 8 percent to account for the uncertainty surrounding CSP project costs and the impact of the centralized Program Administrator on soft costs, the expectation that costs may vary widely among projects, and Staff's desire to drive the cost to stand up the program as low as possible. The results of this analysis are provided in Table 6.

Table 6: Bill Credit Rate Modeling Outcomes						
Program Size	**Bill Credit Rate**	**Project Manager 20y IRR**	**PGE Ratepayer Impact (% of Rev. Req.)**	**PAC Ratepayer Impact (% of Rev. Req.)**	**IPC Ratepayer Impact (% of Rev. Req.)**	**Gross 20y Ratepayer Impact ($M)**
25% (40.3 MW)	RVOS	N/A	0.006%	0.007%	0.006%	$5.15
	Retail fixed	4.11%	0.053%	0.043%	0.053%	$39.18
	Retail + escalator	6.54%	0.075%	0.063%	0.081%	$56.16
50% (80.5 MW)	RVOS	(12.78%)	0.009%	0.009%	0.007%	$6.91
	Retail fixed	5.40%	0.102%	0.083%	0.102%	$75.44
	Retail + escalator	7.76%	0.147%	0.122%	0.158%	$109.66
75% (120.8 MW)	RVOS	(9.55%)	0.008%	0.009%	0.006%	$6.73
	Retail fixed	6.03%	0.148%	0.119%	0.147%	$109.03
	Retail + escalator	8.36%	0.215%	0.177%	0.231%	$160.10
100% (161.0 MW)	RVOS	(8.82%)	0.009%	0.009%	0.005%	$6.96
	Retail fixed	6.22%	0.195%	0.156%	0.193%	$143.29
	Retail + escalator	8.54%	0.284%	0.234%	0.305%	$211.33

Based on these modeling outcomes, Staff recommends that the Commission define the residential retail rate (interim rate) as the current retail rate with a fixed annual escalator of 2.18 percent. Further, Staff recommends that the commission extend the interim tier to 75 percent of the capacity tier and fully transition to ongoing costs when 80 MW of capacity is subscribed, online, and billing (the transition capacity level).[35] While higher than the 25 percent originally identified by the Commission, Staff and the PA's continued learnings and analysis strongly point to the risk that project availability faces high hurdles unless program costs can be spread across at least 80 MW of active subscribers. Extending the interim rate to exactly 80 MW (50 percent of capacity tier) may not actually allow the program reach 80 MW online and billing. This would require projects to size exactly to each utility's capacity tier with exactly one-hundred percent subscription. Therefore, Staff proposes that the Commission provide the program headroom to reach 80 MW by extending the interim rate to 75 percent of PAC and PGE's interim capacity tier.

Since the draft policy proposal, Staff has recognized that 75 percent of IPC's capacity tier is 2.45 MW. Because this does not allow a 3 MW project to receive a single rate,

[35] As stated previously, 80 MW transition capacity level translates to $1.50/kW/month participant fee and a $75/kW application fee. However, the PA will collect a $5/kW pre-certification application fee and ratepayers will support unfunded ongoing costs until the program reaches the transition capacity tier or 24 months have passed since pre-certification launch.

Staff recommends that the Commission extend IPC's interim rate to 100 percent of its capacity tier. This is approximately 3.3 MW.

Overall, Staff is attempting to balance several important interests with its recommendations. In particular, the need to stand up a challenging program model while minimizing the impact on ratepayers and ensuring low-income participants are not harmed. Staff recognizes that extending the interim rate has implications for ratepayers, adding approximately $5 million per year across the three utilities for 20 years. Staff estimates this will raise revenue requirement by approximately 0.18 – 0.23 percent. These risks should not be discounted when deciding how to implement the bill credit. Nor should the opportunity to course correct before reaching the full capacity tier. However, Staff finds that not extending the interim rate puts the CSP at considerable risk of failure. This is a risk that Staff does not find in line with the direction of the legislature to incentivize participation while minimizing ratepayer impacts, as well as the Commission's strategy to establish a program that is large enough to support the administrative costs associated with a robust program.

Additional recommendations
In addition, Staff recommends the Commission adopt the following measures to address auxiliary learnings from its analysis.

<u>Simplify Crediting Rules</u>: To reduce technology and customer service costs, ease customer acquisition barriers, and protect low-income accessibility, Staff recommends that the Commission waive OAR 860-088-0170(2) requirements from the rules and adopt the following bill mechanics:

- A participant's monthly total bill credit is calculated by multiplying the bill credit rate by the participant's share of total project generation in the month. This will be a dollar value referred to as the "total bill credit".
- If the value of the total bill credit exceeds the participant's total utility bill amount (in dollars), less any other on-bill repayment expenses, the excess bill credit amount (in dollars) is carried forward as a positive balance on the participant's account. This amount is referred to as the carry-over bill credit value.
- At the end of the annual billing cycle, any remaining carry-over bill credit value (in dollars) attributable to CSP participation must be donated to the low-income programs of the electric company serving the participant.

Additional details for implementing the simplified bill mechanics will be established in the PIM.

<u>Small project carve out</u>: Staff recommends that the Commission include both 360 kW and under projects, and projects with a non-profit or public entity as the Project Manager in the 25 percent carve-out. Staff recommends that the 25 percent carve-out

apply for the entire amount of capacity allocated at the interim rate (i75 percent of each utility's capacity tier). Staff also recommends using the definition of non-profit organization adopted by the Commission for the utilities' voluntary renewable energy grant programs:

> For the purposes of voluntary renewable programs, the term non-profit shall include any mutual benefit corporation, public benefit corporation, religious corporation, municipal corporation, or Indian Tribe as defined by Oregon Law. [36]

Staff will work with the PA to monitor the usefulness of this carve-out and bring forward recommendations to amend or otherwise modify this carve-out based on actual project development data after pre-certification launches.

<u>Support Project Manager acquisition costs:</u> Staff recommends that the utilities provide at least one communication per year that informs all customers of the CSP opportunity, and directs customers to 1) the list of available projects on the CSP website, and 2) the PA's contact information. The cost of these activities will be considered start-up costs until the 80 MW capacity transition level is reached. At that point, Staff and the PA will work with utilities and stakeholders to determine if further support is required.

Staff proposes to work with the PA, utilities, and stakeholders to identify the specific consumer outreach actions that will best leverage greater program outcomes for a reasonable ratepayer cost.

Next steps to implement CSP policy recommendations
Staff's recommends the following next steps to implement its recommendations:

- The PIM will reflect all policy decisions, including those related to bill credit and low-income requirements.
- The Commission will waive OAR 860-088-0040(2)(d) and adopt additional interconnection measures as described in this memo and detailed in Attachment A.
- Staff will continue development of interconnection cost-sharing mechanisms by order.
- OPUC will Issue an RFI for third-party interconnection reviewer services.
- The Commission will adopt a full transition to ongoing costs by order at 80 MW and the initial administrative fees found in Table 4.
- The Commission will waive OAR 860-088-0170(2) requirements and adopt the

[36] *See* Commission Order No. 17-455, Docket No. UM 1020, November 8, 2017.

simplified bill credit issues by order.
- The utilities will provide at least one communication per year to inform all customers on eligible rate schedules of the CSP opportunity.

Conclusion

On June 29, 2017, the Commission adopted administrative rules for the CSP. The Commission recognized that certain program decisions would be best resolved later in the implementation process. Staff is working with the PA to propose solutions for the majority of outstanding implementation decisions in the program implementation manual (PIM); however, several policy issues are significant and complex enough to warrant a separate Commission decision process. These decisions are specific to four policy areas and represent critical inputs for Project Managers to prepare projects for pre-certification: interconnection, low-income requirements, transition to ongoing costs, bill credit rate. Therefore, these decisions must be resolved prior to pre-certification launch, which is scheduled for December 16, 2019, and the adoption of the PIM.[37]

Attachment A provides a summary of Staff's final recommendations and the Commission actions to implement them. With these recommendations, Staff seeks to balance several interests, particularly the need to stand up a challenging program model, while minimizing the impact on ratepayers and ensuring low-income participants are not harmed. The work leading up to these recommendations spans many years, including a significant amount of stakeholder and PA effort over the past few months. Staff greatly appreciates the efforts of all stakeholders involved in the development of these final recommendations.

PROPOSED COMMISSION MOTION

Approve Staff's proposals for CSP interconnection, low-income requirements, transition to ongoing costs, and bill credit rate policy decisions, detailed in Attachment A.

[37] *See* Docket No. UM 1930, Staff's amended schedule, September 16, 2019.

Attachment A – Summary of Staff final recommendations

- Waive OAR 860-088-0040(2)(d) and adopt the following interconnection measures:
  - Establish a streamlined CSP interconnection process that considers eligible generators within a limited scope and process.
  - Begin developing models for cost-sharing between generators:
    - In the near term, support voluntary cost-sharing between CSP generators by directing 1) the utilities to study multiple CSP generators jointly upon request, with conditions; and 2) the PA to host online resources that help CSP generators identify other electrically relevant CSP generators to independently pursue joint utility study and cost-sharing.
    - In 2020, initiate a Staff-led process to continue discussion of pre-emptive distribution cost-sharing and community energy zones with a broader stakeholder group, including UM 1930, UM 2000, and UM 2005.
  - Simplify metering requirements for small generators.
  - Issue a Request for Information (RFI) for third-party expert interconnection study review services.
  - Adopt an enhanced pre-application report for non-profit and public Project Managers.
  - Direct PacifiCorp to provide additional information on the process to address the backlog of Oregon interconnection applications as it impacts CSP projects.
- Adopt the following low-income policies by order and in the PIM:
  - Require a minimum of 10 percent of each CSP project's capacity to be allocated for use by qualifying low-income residential customers.
  - Require a 20 percent subscription discount for qualifying low-income subscriptions.
  - Define a qualifying low-income residential customer as:
    - A residential Idaho Power Company (IPC), PacifiCorp (PAC), or Portland General Electric (PGE) customer that meets the income and all other requirements set forth in the PIM.
    - A residential utility account holder with a utility allowance or other requirements of rent-assisted housing.
    - An affordable housing provider that directly pays for the electricity costs of residential tenants with household incomes that meet the income requirements set forth in the PIM and additional conditions for direct tenant benefits.
- Adopt the following policy to transition from start-up to ongoing costs by order, as recommended in the draft policy proposal released September 13, 2019:

- Limit start-up costs to specific program development activities per the Staff draft policy proposal released on September 13, 2019.
- Establish ongoing administrative fees for participants and pre-certification applicants at the level required to recover ongoing costs when 80 MW of CSP capacity are subscribed and billing.

Table 7: Proposed Tentative Initial Administrative Fee Schedule

Approx. MW subscribed and billing across utilities	% Capacity Tier (for context)	General Participant Admin Fee ($/kW/mo)	LI participant fee	Pre-certification Application fee ($/kW)
80.5	50%	$1.50	$0	$75

- Before 80 MW of CSP capacity is subscribed and billing:
    - Collect the full administrative fee from participants.
    - Collect $5/kW pre-certification application fee from Project Managers.
    - Backfill unfunded administrative costs with ratepayer funds until 80 MW is subscribed and billing.
- Once 80 MW of CSP capacity is subscribed and billing:
    - Collect the full administrative fee from participants.
    - Collect the full pre-certification application fee from Project Managers.
- If the program has not reached the 80 MW subscribed and billing 24 months following pre-certification launch, pause pre-certification to determine the appropriate next steps.

- Adopt the following bill credit rate policies by order:
    - Adopt the retail rate with a fixed escalator as the interim bill credit rate. This rate will be updated for new pre-certified projects annually to reflect the contemporary residential retail rate and the utilities' latest general rate case.
    - Extend the interim bill credit rate to 75 percent of PAC and PGE's capacity tier.
    - Extend the interim bill credit rate to 100 percent of IPC's capacity tier.
    - Allow non-profit and government entities serving as Project Managers to qualify for the small project carve-out, and extend the 25 percent carve-out to apply to entire amount of each utility's capacity tier.
- Waive OAR 860-088-0170(2) requirements and adopt the following bill mechanics:
    - A participant's monthly total bill credit is calculated by multiplying the bill credit rate by the participant's share of total project generation in the month. This will be a dollar value referred to as the "total bill credit".

    - If the value of the total bill credit exceeds the participant's total utility bill amount (in dollars), less any other on-bill repayment expenses, the excess bill credit amount (in dollars) is carried forward as a positive balance on the participant's account. This amount is referred to as the carry-over bill credit value.
    - At the end of the annual billing cycle, any remaining carry-over bill credit value (in dollars) attributable to CSP participation must be donated to the low-income programs of the electric company serving the participant.
    - Establish additional details for implementing the simplified bill mechanics in the PIM.
- Direct the utilities to provide at least one communication per year to all customers on eligible rate schedules that informs of the CSP opportunity and directs customers to the list of available projects on the CSP program website and the Program Administrator's contact information.

Tranche	1	

Basic System Inputs

Utility Company	PGE	
Commercial Operation Year	2020	
Start Month	4	
Expected Operation Life	40	years
System Size DC	3,000,000	watts-DC
System Size AC	2,200,000	watts-AC
Tracking	Single-axis	
Production Ratio	1,392	kWh/kW-DC
First Year Generation	4,176,000	kWh/yr
Degradation	0.50%	
Discount Rate/Specific Rate of Return	3%	

Financing Inputs

Percentage financed	0.00%
Term	15
Interest Rate	6.00%
Financing Fees (% of Loan)	3.00%

Tax Credits & Incentives

Investment Tax Credit Percentage	26%
Bonus Depreciation	0%
Tax Rate	21.00%
[Optional - Incentives/Grant #1]	$0
[Optional - Incentives/Grant #2]	$0

Upfront Capital Costs

	Cost ($/watt-DC)	Cost (Total $)
EPC (Equipment & Construction) Cost	$1.05	$3,150,000
Developer Fee/Expenses	$0.05	$150,000
Interconnection Cost	$0.10	$300,000
Subscriber Acquisition Cost	$0.05	$150,000
Property Purchase		$0
Other Development Cost	$0.05	$150,000
[Optional - Other Cost #1]		$0
[Optional - Other Cost #2]		$0
[Optional - Other Cost #3]		$0
Base Capital Costs	***$1.30***	***$3,900,000***
PA Project Application Fee	$0.08	$225,000
Total Capital Costs	***$1.38***	***$4,125,000***

Expenses (CSP PPA Years 1-20)

	Cost ($/watt-DC)	Annual Cost ($/year)	Annual Escalation (%)	
Operation & Maintainance	$0.010	$30,000	1.50%	
Property Lease		$14,000	2.50%	
Property Taxes		$15,400	0.00%	
Subscriber Management		$2,500	1.00%	
Insurance	$0.005	$15,000	0.00%	
Equipment replacement reserve	$0.003	$7,500	0.00%	*Assumes 15 year replacement
Other Management		$15,000	0.00%	
Miscellaneous expenses		$0	0.00%	
[Optional - Other Expense #1]		$0	0.00%	
[Optional - Other Expense #2]		$0	0.00%	
[Optional - Other Expense #3]		$0	0.00%	

Expenses (PURPA QF Years 21-40)

	Cost ($/watt-DC)	Annual Cost ($/year)	Annual Escalation (%)
Operation & Maintainance	$0.005	$15,000	0.00%
Property Lease		$22,381	2.50%
Property Taxes		$2,000	0.00%
Subscriber Management		$0	0.00%
Insurance	$0.003	$7,500	0.00%
Equipment replacement reserve	$0.000	$0	0.00%
Other Management		$15,000	0.00%
Miscellaneous expenses		$0	0.00%
[Optional - Other Expense #1]		$0	0.00%
[Optional - Other Expense #2]		$0	0.00%
[Optional - Other Expense #3]		$0	0.00%

Program Fees

PA Project Application Fee	$225,000	
Ongoing PA Fee (deducted from Bill Credit)	$ 1.50	/kW/month
	$ 0.0129	/kWh/year
Annual PA Fee Escalation	-5.00%	

Bill Credit

Retail Rate in Year 1	0.1103	$/kWh
Bill Credit Rate in Year 1	0.1103	$/kWh
LI Bill Credit Rate in Year 1	0.1103	$/kWh
Bill Credit Escalation	2.0%	/year
Net Bill Credit (less PA Fee)	$ 0.0974	/kWh
Avoided Costs Rate (Year 21)	$ 0.0600	
Avoided Costs Escalation	2%	

Project Subscription Levels

% Project Capacity Subscribed Year 1	80%
Avg. % Project Subscribed Year 2+	95%
% of Low Income Subscribers	10%
Preferred Subscription Type	*Variable $/kWh*

Subscription Inputs

Subscriber's Annual Load	9000	kWh/year
Subscriber's Load Growth	-0.50%	/year
Target usage offset	80%	
Subscription size	5.17	kW-DC
Subscription production	7,200	kWh/year

Variable Subscription Inputs

Target % discount/premium from Bill Credit	16.72%	
Annual Escalation %	2.0%	
Subscription Fee per kWh	0.092	$/kWh
Avg variable monthly Fee	$55.11	
Equivalent Subscription Fee per kW	$10.66	/kW
Target Net Discount	5.00%	
Total Fee per kWh	$0.105	

Low-Income Subscriptions - Variable Mode

LI % Discount from Bill Credit	26.00%	
Annual Escalation %	2.0%	
LI Subscription Fee per kWh	$0.0816	/kWh
LI Savings	$0.0287	/kWh
LI PA Fee Discount	100%	
Avg LI savings per kW of Subscription	$3.3266	/kW per month
Equivalent Subscription Fee per kW	$9.4682	/kW
Target Total Bill Credit Savings	26.00%	
Bill Credit Adder	0.00%	
Bill Credit Adder per kWh	$0.0000	/kWh

Customer Production & Consumption

Input monthly production for a 1 kW system at the proposed project location from PVWatts or other source

Tracking Assumption | Single-axis | PVWatts Calculator

Month	kWh/kW per month	Production Ratios	OR Load Profile (% energy used per month)	Est Subscriber Load (kWh)	Subscription Production (kWh)
January	45	3%	13%	1149	233
February	82	6%	13%	1149	424
March	98	7%	9%	766	507
April	137	10%	6%	574	709
May	154	11%	4%	383	797
June	161	12%	4%	383	833
July	200	14%	6%	574	1034
August	179	13%	6%	574	926
September	144	10%	4%	383	745
October	94	7%	9%	766	486
November	54	4%	13%	1149	279
December	44	3%	13%	1149	228
Total	1392			9000	7200

Fee Schedules

Year No.	Year	Bill Credit Rate	PA Annual Fee	Subscription Fee
1	2020	0.1103	$1.50	$0.0919
2	2021	0.112506	$1.43	$0.0937
3	2022	0.11475612	$1.35	$0.0956
4	2023	0.117051242	$1.29	$0.0975
5	2024	0.119392267	$1.22	$0.0994
6	2025	0.121780112	$1.16	$0.1014
7	2026	0.124215715	$1.10	$0.1034
8	2027	0.126700029	$1.05	$0.1055
9	2028	0.129234029	$1.00	$0.1076
10	2029	0.13181871	$0.95	$0.1098
11	2030	0.134455084	$0.90	$0.1120
12	2031	0.137144186	$0.85	$0.1142
13	2032	0.139887069	$0.81	$0.1165
14	2033	0.142684811	$0.77	$0.1188
15	2034	0.145538507	$0.73	$0.1212
16	2035	0.148449277	$0.69	$0.1236
17	2036	0.151418262	$0.66	$0.1261
18	2037	0.154446627	$0.63	$0.1286
19	2038	0.15753556	$0.60	$0.1312
20	2039	0.160686271	$0.57	$0.1338
21	2040	0.060	$0.54	$0.1365
22	2041	0.0612	$0.51	$0.1392
23	2042	0.0624	$0.49	$0.1420
24	2043	0.0637	$0.46	$0.1448
25	2044	0.0649	$0.44	$0.1477
26	2045	0.0662	$0.42	$0.1507
27	2046	0.0676	$0.40	$0.1537
28	2047	0.0689	$0.38	$0.1568
29	2048	0.0703	$0.36	$0.1599
30	2049	0.0717	$0.34	$0.1631
31	2050	0.0731	$0.32	$0.1664
32	2051	0.0746	$0.31	$0.1697
33	2052	0.0761	$0.29	$0.1731
34	2053	0.0776	$0.28	$0.1766
35	2054	0.0792	$0.26	$0.1801

Year No.	Year	LI Bill Credit Rate	LI Annual PA Fee	LI Subscription Fee
1	2020	0.1103	$ -	$0.0816
2	2021	0.112506	$ -	$0.0833
3	2022	0.11475612	$ -	$0.0849
4	2023	0.117051242	$ -	$0.0866
5	2024	0.119392267	$ -	$0.0884
6	2025	0.121780112	$ -	$0.0901
7	2026	0.124215715	$ -	$0.0919
8	2027	0.126700029	$ -	$0.0938
9	2028	0.129234029	$ -	$0.0956
10	2029	0.13181871	$ -	$0.0975
11	2030	0.134455084	$ -	$0.0995
12	2031	0.137144186	$ -	$0.1015
13	2032	0.139887069	$ -	$0.1035
14	2033	0.142684811	$ -	$0.1056
15	2034	0.145538507	$ -	$0.1077
16	2035	0.148449277	$ -	$0.1099
17	2036	0.151418262	$ -	$0.1120
18	2037	0.154446627	$ -	$0.1143
19	2038	0.15753556	$ -	$0.1166
20	2039	0.160686271	$ -	$0.1189
21	2040	0.060	$ -	$0.1213
22	2041	0.0612	$ -	$0.1237
23	2042	0.0624	$ -	$0.1262
24	2043	0.0637	$ -	$0.1287
25	2044	0.0649	$ -	$0.1313
26	2045	0.0662	$ -	$0.1339
27	2046	0.0676	$ -	$0.1366
28	2047	0.0689	$ -	$0.1393
29	2048	0.0703	$ -	$0.1421
30	2049	0.0717	$ -	$0.1449
31	2050	0.0731	$ -	$0.1478
32	2051	0.0746	$ -	$0.1508
33	2052	0.0761	$ -	$0.1538
34	2053	0.0776	$ -	$0.1569
35	2054	0.0792	$ -	$0.1600

MODEL VARIABLES

Program Variables		
PA Fee	$ 1.50	per kW/ month
LI PA Fee Discount	100%	
PA Fee Annual Step-Down	5%	
Application Fee	$ 75.00	$/kW
Required % of LI subscribers	10%	
Customer Monthly Fixed Bill Amount	$ 5.00	
Monthly Volumetric Caps for Customers?	Yes	
Customer Bill Model	Cash-Only Model	
Adoption Variables		
Dropout Rate	15%	
Subscribership Level	95%	
Avg Large project	3,000	kW
Avg Small Project	300	kW
% of Large Projects Completed in Year 2	20%	
% of Small Projects Completed in Year 2	70%	
PA Cost Variables		
Variable App Costs	22%	
Variable Sub Costs	22%	
Startup Reduction	5%	

UTILITY VARIABLES

Nominal Rate**	4.4%
Inflation*	2.8%
Real 2018$ OR Rev Req* - PGE	$ 1,937,818,036
Real 2018$ OR Rev Req* - PAC	$ 1,331,889,672
Real 2018$ OR Rev Req* - IPC	$ 59,953,614
Retail Rate Escalation	2.0%

Fee Type	Who Pays?
Application Fee	Ratepayer
PA Fee	Subscriber

BILL CREDIT RATE

Escalator	2.0%	LI Credit Rate Adder	$ Amount	$ -	0.0%

	Tranche	Rate Type	% of Capacity	MW Tranche Cap	Custom	Rate
PGE	1	Retail	100%	93.15	0.15	0.1103
	2	RVOS	0%	0.00	0.1068807	0.04954
	3	RVOS	0%	0.00	0.04800426	0.04954
	4	RVOS	0%	0.00	0.04800426	0.04954

	Tranche	Rate Type	% of Capacity	MW Tranche Cap	Custom	Rate
PAC	1	Retail	100%	64.60	0.07	0.1005
	2	RVOS	0%	0.00	0.0973845	0.04964
	3	RVOS	0%	0.00	0.04810116	0.04964
	4	RVOS	0%	0.00	0.04810116	0.04964

	Tranche	Rate Type	% of Capacity	MW Tranche Cap	Custom	Rate
IPC	1	Retail	100%	3.27	0.08	0.088
	2	RVOS	0%	0.00	0.085272	0.04853
	3	RVOS	0%	0.00	0.04702557	0.04853
	4	RVOS	0%	0.00	0.04702557	0.04853

PROGRAM ADOPTION

Capacity Available (% of 160 MW)	75%	Adoption Model:	Launch Boom
Capacity Available (MW)	160	Interim Transition Year:	50
Adoption Level (% of Cap. Avail.)	100%	Program Launch Year:	2020
Adoption Level (MW)	160		

Year	Large Projects	Small Projects	Applied MW Capacity
2020	36	20	114.00
2021	-	10	3.00
2022	-	10	3.00
2023			-
2024			-
Total	36	40	120.00

Year	Installed MW Capacity	Annual Adoption	Tot. Adoption	Tot. Installed
2020	-	95%	71%	0%
2021	21.93	3%	2%	14%
2022	76.76	3%	2%	62%
2023	2.55	0%	0%	63%
2024	0.77	0%	0%	64%
Total	102.00	100%	75%	

REFERENCE TABLES

Utility	2016 Oregon System Peak (MW)	% of System	CSP Capacity Tier (MW)
PGE	3,726	57.8%	93.15
PAC	2,584	40.1%	64.60
IPC	130.85	2.0%	3.27
Total	6,441	100.0%	161.0

Utility	Retail Rate	RVOS Rate	Capacity Factor
PGE	0.1103	0.04954	16%
PAC	0.1005	0.04964	15%
IPC	0.088	0.04853	22%
Total			

Utility	Initial Capacity Tier (MW)	Avail. for Small/Med Projects (MW)	Available for Large Projects (MW)
PGE	23.29	5.82	17.47
PAC	16.15	4.04	12.11
IPC	0.82	0.20	0.61
Total	40.26	10	30

Projects Possible			
Utility	min - Sm/Med	Min - LG	Total - Min
PGE	16	5	21
PAC	11	4	15
IPC	0	0	0
Total	27	9	36

* TIPS 20-yr Inflation Forecast
** Staff estimate

UM 1930: Draft proposal for Community Solar Interconnection

Purpose

This report outlines Staff's understanding of the most significant barriers for community solar projects seeking to interconnect with utilities, and proposes a process to address these issues within the timeframe required for a successful community solar program (CSP) launch. Further, this report outlines the next steps to move Staff's proposed solution forward with stakeholders.

Background

Concerns about CSP interconnection

On June 29, 2017, the Public Utility Commission of Oregon (Commission or OPUC) adopted administrative rules for the CSP.[1] The administrative rules require CSP projects to interconnect with the utility in accordance with the State's existing small generator interconnection procedures (SGIP).[2] In the order, the Commission also asked Staff and stakeholders,

> to consider during development of the program implementation manual the potential role of the program administrator ensuring non-discriminatory access and evaluating whether the interconnection process is fair and functional for projects seeking to enter the community solar program.[3]

At the July 26, 2018 Project Details Subgroup meeting, stakeholders raised concerns that interconnection costs may prevent the successful launch of the CSP.[4] Further, Subgroup participants sought clarity about the need for CSP projects to interconnect as Qualifying Facilities (QF) under the Federal Public Utility Regulatory Policies Act (PURPA), because interconnecting as a QF could further increase interconnection costs.[5] Staff committed to work

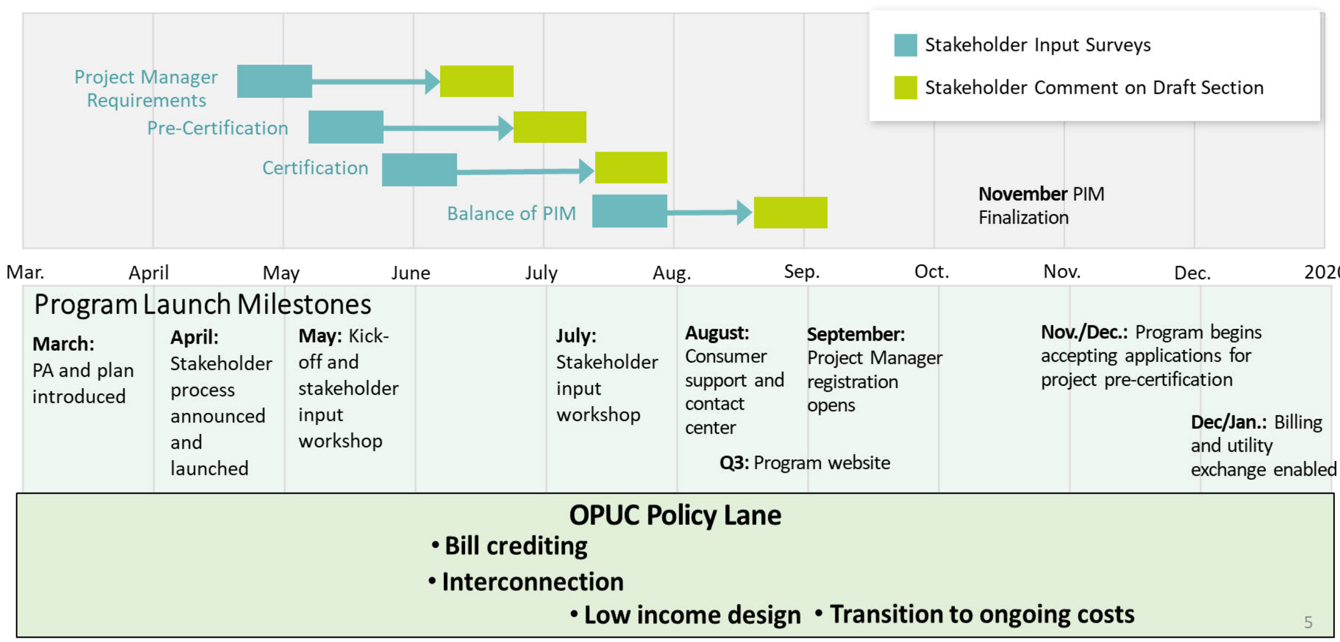
[1] *See* OAR Ch. 860, Div. 88; *In the Matter of Rules Regarding Community Solar Projects* (AR 603); Order No. 17-232.
[2] The SGIP are outlined in Oregon Administrative Rules Chapter 860, Division 82.The SGIP are implemented by utilities and, therefore, influenced by utility decisions and practices, as well.
[3] Order No. 17-232, p. 10.
[4] Order No.17-458 approved Staff's request to develop topical, stakeholder-led subgroups to identify and scope Community Solar Program implementation actions that can be taken by Staff and stakeholders concurrently with the issuance of a Request for Proposals (RFP) for a Community Solar third-party Program Administrator. The Project Details Subgroup scope included: interconnection, the role of existing projects, any carve-outs for smaller projects, the flow of needed pre-certification items from projects, deposits and associated process, PPA requirements, QF project requirements, and the CSP project queue.
[5] Oregon's investor owned utilities require QF interconnections as Network Resource Interconnection Status (NRIS), as described later in this report. Generators requesting NRIS have a higher level of interconnection requirements than generators interconnecting with

with the Department of Justice (DOJ) to evaluate these concerns and provide clarity about the QF requirement.

On February 5, 2019, Staff shared DOJ's finding that Commission rules require CSP projects to interconnect as QFs (See Attachment A). In its subsequent February 14, 2019 CSP implementation status update, Staff recognized the need to identify near-term opportunities to reduce interconnection barriers for CSP projects within the legal and procedural framework of a QF interconnection.

On May 10, 2019, Staff and the PA Team (consisting of the CSP Program Administrator, Energy Solutions, the Low Income Facilitator, Community Energy Project, and Energy Trust of Oregon) released a plan to develop the program implementation manual (PIM), address outstanding policy issues, create a software platform to facilitate billing and data exchange functions, and begin accepting project pre-certification applications by the end of 2019 (See Figure 1).

Figure 1: Oregon Community Solar Implementation Plan



Additional interconnection proceedings

On February 14, 2019, the Commission opened the UM 2000 Broad Investigation into PURPA and UM 2001 Investigation into Interim PURPA Action. Among other issues related to implementation of PURPA, Docket Nos. UM 2000 and 2001will examine interim actions to relieve interconnection pain points and longer-term actions to address the systemic barriers to small generator interconnection. Table 1 summarized the scope of both investigations.

Energy Resource Interconnection Service (ERIS). The higher level of requirements can lead to additional interconnection costs.

Table 1: UM 2000 and UM 2001 Investigation Scope

Docket	**UM 2000**	**UM 2001**
Scope	Staff's May 28, 2019 UM 2000 Draft White Paper proposed that the Commission organize the investigation around four categories of issues: avoided costs, contracts, interconnection, and planning. Proposed interconnection issues include: • How interconnection costs are allocated between small generators and the utility (e.g., should transmission providers share the costs of transmission system upgrades), as well as between different small generators in the queue (e.g., cluster studies). • Whether the manner in which utilities process generator applications in serial order, based on queue number, should be modified. • The timeliness of utility interconnection studies and process. • The ability to use third-parties to perform interconnection studies and system upgrades.	Develop an interim method to update avoided costs and create more transparent interconnection information, including: • Publicly posting interconnection queue and studies • Publicly posting distribution system information (e.g., feeder and substation loading and capacity) • Publicly posting interconnection milestones (e.g., utility timelines to meet • Forming an interconnection data workgroup to advise Staff on specific interconnection data to be shared.
Timeline	The Commission has not adopted a timeline for addressing interconnection issues scoped within UM 2000. Staff's draft whitepaper proposes an investigation or rulemaking to address	All actions within the UM 2001 scope will be implemented by January 2020

On March 21, 2019, the Commission opened UM 2005 Investigation into Distribution System Planning (DSP). Staff's goal for DSP is to ensure that utility distribution-level investments and operational decisions maximize system efficiency and value for utility customers. This includes consideration for how utilities plan for additional distributed energy resources and what system investments utilities should make to ensure the efficient integration of distributed energy resources, among other customer options. On June 14, 2019, Staff released an updated schedule for UM 2005 in which Commission guidance for utilities to file initial plans will be provided in June 2020. Following Commission guidance, the utilities will have sufficient time to develop and file plans for Commission and stakeholder input. While DSP is expected to ensure that utilities are planning for and investing in the efficient interconnection of resources like CSP, Staff does not anticipate DSP will directly address or drive these investments until the end of 2020, at the earliest.

The need to address CSP interconnections
Based on Staff's understanding that CSP Project Managers (PMs) require certainty about interconnection costs and process prior to applying for pre-certification, Staff finds that a fair and functional process should be in place before the end of 2019. The remainder of this report will assess whether additional efforts are required to ensure fair and functional process by summarizing the following:

- Staff's findings that interconnection under the existing SGIP may not be functional due to delays in processing applications and prohibitive costs for generators;
- Staff's current understanding of the key drivers of interconnection costs for small generators; and
- Staff's proposal to address these key drivers in a manner that will be functional within the CSP launch timeline.

Overview of interconnection process for CSP

The CSP administrative rules require projects to interconnect with utilities under the process provided in Oregon Administrative Rules (OAR) Chapter 860, Division 82 Small Generator Interconnection Rules. These rules (aka Small Generator Interconnection Procedures or "SGIP") were adopted in 2009 and govern state-jurisdictional interconnections for generators 10 MW and under.[6]

The SGIP outlines the process for utilities to identify the equipment and other upgrades required to safely interconnect a generator to the transmission or distribution network. Interconnection review is performed through various studies that vary in cost and intensity dependent upon the generator's expected impact on the system.

The SGIP contemplates two types of upgrades[7]:

- **Interconnection facilities:** facilities and equipment required by a public utility to accommodate the interconnection of a small generator facility to the public utility's transmission or distribution system and used exclusively for that interconnection. Interconnection facilities do not include system upgrades; and
- **System upgrades:** addition or modification to a public utility's transmission or distribution system or to an affected system that is required to accommodate the interconnection of a small generator facility.

  Staff believes that, functionally, there are two distinct types of system upgrades:
  - **Distribution upgrades:** located at or past the POI, needed to safely and reliably accommodate the generation on the local network i.e. does the equipment on the local system have the physical capacity to handle the presence of this additional generation?

[6] State jurisdictional interconnections include interconnections for retail transactions such as net metering and for PURPA sales when a Qualifying Facility generator sells its entire output to the interconnecting utility. The Federal Regulatory Commission (FERC) also has interconnection procedures developed for interconnections subject to FERC jurisdiction.
[7] *See* OAR 860-082-0015.

- o **Transmission upgrades:** located at and past the POI, needed to sink the generation to load i.e. does the system have the physical capacity and does the utility have the contractual rights to deliver this generation to local area load or the next closest area with load?

The review process has four tiers that determine the process to identify necessary upgrades:

- Tier 1 is for very small systems (<25 kW);
- Tier 2 is for generators under 2 MW that connect to distribution system and pass screens designed to identify generators that should require minimal upgrades to safely interconnect;
- Tier 3 is for generators under 10MW that do not export energy beyond the point of interconnection; and
- Tier 4 is the default tier for generators under 10 MW that do not satisfy the eligibility or the requirements of Tiers 1-3.

CSP generators must be a least 25 kW and export power beyond the point of interconnection. Therefore, CSP generators must proceed as Tier 2 or 4 as described above. Prior to making an interconnection request, generators can request pre-application information, including relevant existing studies and other materials that may be used to understand the feasibility of interconnecting a small generator facility at a particular point on the public utility's transmission or distribution system. These studies do not necessarily identify what may be prohibitively expensive interconnection facilities or system transmission upgrades (distribution and/or transmission) needed for a particular generator' interconnection.[8]

Tier 2 review is similar to FERC's Fast Track process. For eligible generators, the transmission provider (the utility) holds an optional scoping meeting with the generator, then determines whether the generator meets the screening criteria set forth in the SGIP. If the generator passes the screens, it can proceed with execution of the interconnection agreement. If the generator fails the screens, the interconnection application can be reviewed under Tier 3 or 4, depending on whether it exports power beyond the point of interconnection.

Tier 4 is similar to the study process for large generator interconnections (>20 MW). The study process begins with a scoping meeting between the generator and transmission provider, followed by three studies (Feasibility, System Impact, and Facilities) to evaluate the potential adverse impacts of the generator on the transmission and/or distribution network, whether upgrades are required to safely interconnect the generator, and the estimated cost of required upgrades. Studies include technical analyses such as power flow analysis, sort-circuit analysis, and grounding review. The transmission provider and generator may agree to waive any of the studies.[9]

While the state's SGIP does not specifically identify the service under the SGIP as Network Resource Interconnection Service (NRIS) or Energy Resource Interconnection Service (ERIS), the Oregon utilities require small generators that are QFs to interconnect with NRIS. Whether a

[8] See OAR 860-082-0020.
[9] OAR 860-082-0060(4).

generator is interconnecting with ERIS or NRIS determines the studies the utility performs to determine whether it can safely and reliably interconnect the generator.

- **Network resource:** The utility is responsible to treat the generator like its own network resources and deliver the generator output on a firm, uninterruptible basis to network load. In addition to identifying the distribution upgrades required to safely and reliably integrate the additional generation on the local system, the interconnection studies account for the ability to deliver the power to network load during the most severe conditions. If local generation exceeds local load under the severe study conditions, the study will identify needed transmission upgrades determine what is required to export the generation to the next closest load.
- **Energy resource**: The utility is responsible to deliver the generator output on the existing firm or non-firm system capacity on an "as available" basis – for the most part, the utility will only consider the ability for the generator to "plug into" the system. If transmission upgrades are required to deliver the generation to load, those are assessed and secured outside of the interconnection process when the generator makes a transmission service request e.g., securing point-to-point transmission.

Once the small generator receives results from all of the necessary studies and agrees to pay for the necessary interconnection facilities and system upgrades, it can execute an interconnection agreement with the utility. After the agreement, the transmission provider will perform the required upgrades and the generator will complete construction of the facility in compliance with utility requirements.

Ensuring a fair and functional process

To determine whether the SGIP provides a fair and functional process for CSP, Staff reviewed the concerns raised by stakeholders, including prospective CSP generators, in UM 1930 and in UM 2000. Further, Staff analyzed publicly available interconnection queues and interconnection studies. Finally, Staff met multiple times with Idaho Power Company (IPC), PacifiCorp (PAC), and Portland General Electric (PGE) to further understand the challenges facing generators subject to the SGIP.

Staff notes that PAC posts its small generator interconnection queue and associated interconnection studies publicly. PGE and IPC do not post this information, but have been asked to do so in 2019 under UM 2001. Therefore, the queue and cost data Staff has been able to analyze relates to CSP projects seeking to interconnect with PAC. Staff recognizes the need to further examine interconnection issues with PGE and IPC to the extent that PAC issues are not universal to utilities subject to the SGIP.

Based on available information, Staff's analysis includes the following findings:

1. CSP interconnection within PACs service area is highly unlikely in at least several locations:

   Analysis of the PAC interconnection queue indicates that PAC has received 74 interconnection requests from small solar generators (≤10 MW) located in Oregon 2016-present. Of these generators applying for interconnection after 2015:

   - Zero have reached commercial operation.

- Three have executed an interconnection agreement (one has since terminated).
- None of the three projects that executed an interconnection agreement since 2015 were QFs.
- 45 have withdrawn or been removed for lack of progress.

Staff understands from input within UM 1930, UM 2000, and additional activities that the lack of small generators interconnecting with PacifiCorp is primarily driven by interconnection costs. Referring back to the 74 generators mentioned previously, nineteen (26 percent) proceeded with interconnection studies (presumably after an initial scoping meeting with the utility indicated that interconnection studies would likely produce prohibitive upgrade costs). Of those nineteen, Staff's basic analysis of the studies showed that the total of all upgrade costs to be borne by the generators fell within a range from $274,000 to $42,199,000 ($40 million were transmission upgrades), with a median of $2,150,000 per study. This includes costs for all upgrades required past the point of interconnection on the distribution and transmission system. To provide context to these upgrade costs, a National Renewable Energy Laboratories 2018 assessment of interconnection cost estimates required of generators between 100 kW and 20 MW in the West found that upgrade costs per study ranged from $23,000 to $19.7 million, with a median of $306,000.[10] This context is purely illustrative and limited by the widely variable nature of interconnection upgrades. The cost and type of upgrades (distribution or transmission) estimated for a generator are specific to the generator's location, project design, the makeup of other generators in the area or in queue, and additional characteristics of the generator and utility system.

Further, PAC has not posted an interconnection study for an Oregon interconnection request received after May 29, 2018, because the amount of generation considered in-service in an interconnection study (i.e., the aggregate of existing generation, higher-queued proposed generation, and generators with executed agreements) its Balancing Authority Area (BAA) has reached levels that exceed load in that BAA. Under this condition, new interconnection requests have produced a non-viable interconnection study result. PAC has proposed a new Interconnection Business Practice (Business Practice No. 73) to help interconnection applicants understand whether changing the project design might resolve the non-viable determination.[11] The business practice does not resolve constraints in the underlying study environment and system. PAC has not indicated an effective date for the business practice or whether it plans to revise it in response to comments.

2. Interconnection may be prohibitive for projects in PGE and IPC service territory, as well.

[10] National Renewable Energy Laboratory, *Review of Interconnection Practices and Costs in the Western States, 2018, p.12*. https://www.nrel.gov/docs/fy18osti/71232.pdf
[11] https://www.oasis.oati.com/woa/docs/PPW/PPWdocs/BP73.pdf

While the same level of public data is not yet available within PGE and IPC's interconnection queue, anecdotal UM 2000 stakeholder input suggests that interconnection costs and timelines may not be functional for a successful CSP launch. See Attachment B for an excerpt from the UM 2000 summary of concerns raised at the April 5, 2019 workshop. In addition, PGE and IPC have been subject to disputes and complaints related to interconnection costs and timelines for small generators.

3. The CSP launch timeline requires a near-term, temporary solution that is specific to CSP projects:

Staff finds that, while efforts are underway to address these and other small generator interconnection issues holistically under UM 2000, the timeline is to be determined and will not be functional for projects to have the interconnection process certainty required to apply for CSP pre-certification at the end of 2019..

Based on these findings, Staff assessed the primary drivers of interconnection costs, identified a near-term solution to address the most significant cost drivers for CSP projects in a functional timeframe, and developed a process to move the solution forward.

Assessment of interconnection barriers for CSP projects

Staff understands that a broad range of interconnection issues have been raised; however, Staff has identified the following most significant drivers of interconnection costs for small solar generators in Oregon:

<u>Assignment of costs to small generators:</u> Under the current SGIP, generators are required to assume the cost of all "system upgrades," in order to execute an interconnection agreement. There is no mechanism for sharing costs with the transmission provider (the utility) or other generators that may benefit from the upgrades.

Further, for purposes of Oregon's SGIP, the upgrades allocated to the generator include transmission system upgrades. Under FERC's LGIP and SGIP, however, the costs of interconnection-related transmission system upgrades are allocated to the transmission provider rather than the interconnecting generator because they are presumed to benefit all users of the transmission system. This presumption does not exist for Oregon jurisdictional interconnections under Oregon's SGIP.

In its order adopting the SGIP, the Commission specifically noted that its cost allocation rule differed from FERC's, but concluded the proposed Oregon Administrative Rules:

> include language that is meant to strictly limit a public utility's ability to require one small generator facility to pay for the cost of system upgrades that primarily benefit the utility or other small generator facilities, or that the public utility planned to make regardless of the he small generator interconnection.[12]

[12] Order No. 09-196, pp. 4-5.

However, the Commission's intention to strictly limit a public utility's ability to require generators to pay for upgrades to the system upgrades is not necessarily evident in the language of the cost allocation rule adopted by the Commission. Instead, OAR 860-082-0035 simply requires the interconnection applicant to "pay the reasonable costs of" interconnection facilities and system upgrades.

Further, the utilities' small generator interconnection agreements (SGIA) do not include any reference to cost allocation of system upgrades that may benefit the transmission provider. With respect to system upgrades that may benefit other generators, the SGIA states that the generator paying for the upgrade may receive compensation from future interconnecting generators, but under "separate rules promulgated by the Commission or by terms of a tariff filed and approved by the Commission."

<u>Network Resource Interconnection Service Requirement:</u> Requiring generators to bear costs of all system upgrades may be particularly burdensome under the utilities' practice to require that QFs interconnect with Network Resource Interconnection Service (NRIS). Although the SGIP do not specifically require or even contemplate that QFs interconnect with NRIS, IPC, PAC, and PGE require that they do so regardless of size and interconnection point (distribution versus transmission). For NRIS, the Transmission Provider studies the Transmission System at Peak Load, under a variety of stressed conditions, with all designated network resources operating at full capacity, to determine whether, with the Generator Facility at full output, the aggregate of generation in the local area can be delivered to the aggregate of load, consistent with the Transmission Provider's reliability criteria and procedures.[13] The utilities explain that they require QFs interconnect with NRIS because the utility's market function is responsible for making that transmission service request on behalf of QFs. If QFs do not interconnect with NRIS and pay for the upgrades necessary for NRIS, the utility would be responsible for any upgrades needed for transmission service to deliver the QF's output to load.

Under FERC's SGIP, a generator under 20 MW interconnects with a service like Energy Resource Interconnection Service (ERIS). For ERIS, an interconnecting generator is responsible for system upgrades required to "plug into" the system and flow the output of its facility onto the Transmission Provider's transmission system in a safe and reliable manner.[14]

Notably, NRIS is not available to small generators under FERC's SGIP. If a small generator would like to request NRIS, it must proceed under FERC's Large Generator Interconnection Procedures.

If a higher queued generator in a relevant area requires system upgrades, the lower queued small generator must bear the cost of those upgrades if the higher queued generator has stalled. Due to this issue of assigning upgrade costs in serial queue order, utilities can require

[13] Standardization of Generator Interconnection Agreements and Procedures, 104 FERC 61,103 (2003 WL 21725988).
[14] Id. 61, 136.

a very small generator to bear hundreds of millions of dollars in costs to construct a transmission line needed to serve a generator that has not, and may not ever, come online.

Through the CSP and UM 2000 discussions, the utilities explain that they require QFs to obtain NRIS to ensure firm, non-interruptible delivery of the QFs' generation to network load, and so that costs of upgrades necessary to enable firm delivery are paid for by the generator during the interconnection process. The utilities explain that if QFs are allowed to interconnect with ERIS, the utility's merchant function may have to pay for necessary system upgrades as a condition of obtaining transmission service from the utility's transmission function. Although network upgrades are likely to benefit the utility and other transmission customers, the utilities claim that requiring utilities to bear the cost of transmission system upgrades to transmit QF output violates the customer indifference standard of PURPA.

The utilities' decision to require that QFs obtain NRIS is a unilateral one that is not dictated by Div. 82. Div. 82 does not define the interconnection service offered to small generators. Notably, the service is not similar to NRIS and nowhere does Div. 82 require deliverability to load as a condition of interconnection.

<u>Allocation of costs among generators:</u> As alluded to in the previous section, costs are assigned in serial order based on queue position. In other words, the project that first triggers an upgrade bears the full cost of the upgrade that may benefit subsequent generators and there is no mechanism currently used to allocate costs among generators applying to interconnect in a similar area. And, a lower queued generator is required to bear the upgrade costs of higher queued generators in order to come online first. This leaves small generators with otherwise minimal impact to the system bearing the cost of higher queued generators, including large generators that are stalled due prohibitive upgrade costs. It also creates queue bottlenecks and aggravates interconnection backlogs.

The utilities' SGIA does not include a mechanism for cost sharing between the interconnecting generator and any generators that may subsequently use the system upgrades. However, the language makes clear that cost sharing among generators would be pursuant to "separate rules promulgated by he Commission or by terms of a tariff filed and approved by the Commission[,]" and "[s]uch compensation will only be available to the extent provided for in the separate rules or tariff."[15] These separate rules or tariff have not yet been adopted.

<u>Lack of information/control over costs:</u> The issues listed above are exacerbated by generators' lack of control over upgrade costs. Currently, there is not enough comprehensive and transparent information to help site and design projects to avoid prohibitively expensive system upgrades in the first place.

Further, it is difficult to verify the conclusions of the studies performed by the utility. This includes both the methodologies to identify the required upgrades and to estimate the costs assigned to those upgrades. While generators can raise formal and informal disputes about specific studies to the Commission, this is not an efficient mechanism to ensure appropriate

[15] Interconnection Agreement for Small Generating Facility, Art. 4.4.

upgrades and costs are identified for all generators. And, this process can exacerbate congestion in the interconnection queue. Staff does not have the resources to adequately verify these study methodologies and outcomes, either.

Finally, there is no realistic ability for generators to hire third-parties to conduct studies or build necessary facilities in place of the utility.

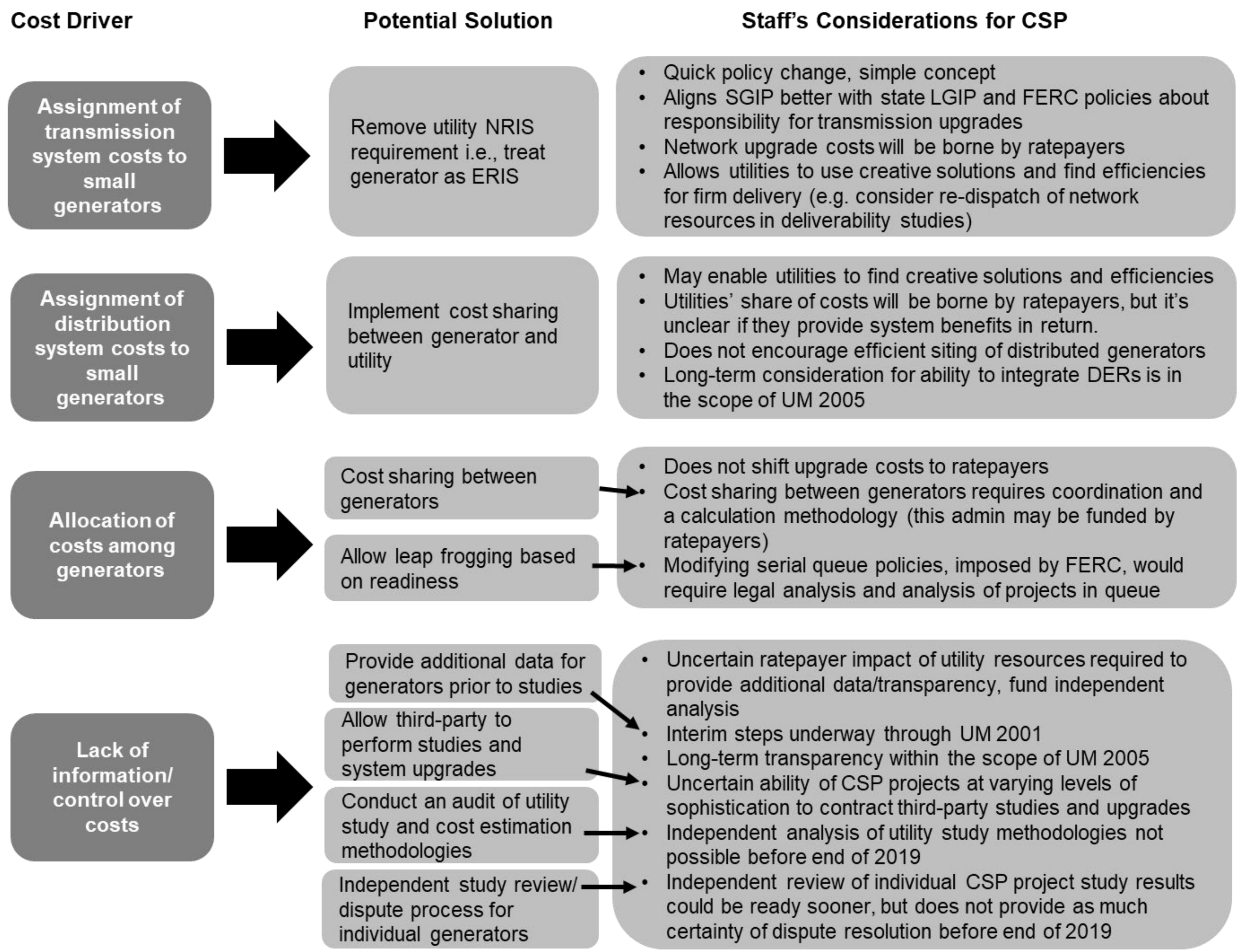
Delay in conducting interconnection studies: In addition to drivers of prohibitive costs, utility delays in conducting studies are not functional for the CSP timeline. PacifiCorp has not posted the results of a completed interconnection study since May 2018. There are currently thirty-four requests for interconnection in its queue that have not been studied (or at least there is no posted study). PacifiCorp explains it stopped interconnection studies to work on how to address unsolvable generation/load imbalances stemming from interconnection requests. On June 3, 2019, PacifiCorp implemented Business Practice 73 "Study Models and Assumptions When Modeled Generation Exceeds Study Area Load" addressing what occurs when PacifiCorp determines an interconnection request is infeasible because of an unsolvable generation/load imbalance. When PacifiCorp recommences conducting and posting studies, it will have to tackle at least 34 pending requests for interconnection in Oregon.
These issues are secondary to the risk that CSP projects will not be able to execute an interconnection agreement due to cost and PAC's halt in processing studies.

Addressing the barriers
To develop a proposal to address barriers for CSP projects, Staff identified a range of potential solutions and used the following criteria to identify the most fair and functional solutions for CSP projects:

- Feasibility: Can the solution be implemented before the end of 2019?
    - Could implementation be quick and relatively direct?
    - Does it align with existing practices or guidance?
    - Could it conflict with FERC or other jurisdictional requirements?
- Impact: What impact will the proposed solution have on reducing interconnection costs?
    - Will it incentivize participation in CSP by directly relieving major barriers?
    - Will the solution minimize cost-shifting to ratepayers by ensuring that costs socialized to all ratepayers provide system benefits?[16]

[16] ORS 757.386(2)(b) directs the Commission to adopt CSP rules that, at a minimum incentivize consumers to participate and minimize the shifting of costs to non-participants.

Figure 2: Staff considerations to address key small generator interconnection cost drivers



Proposed Solution

While Staff believes all proposed solutions should be considered by the Commission, the most direct mechanisms to address interconnection costs for CSP projects is to consider how upgrade costs are allocated to CSP generators and whether it's reasonable for all ratepayers to cover a portion of the costs that provide system benefits. Further, Staff finds that the range of proposed solutions for CSP projects have compelling policy considerations for all small generators in Oregon. Therefore, Staff proposes that CSP provide a discrete, capacity limited environment to test the various solutions for broad, long-term consideration under UM 2000. This pilot-based approach provides the opportunity to test the actual ratepayer impacts of modifying the assignment of upgrades costs—where discussion of customer indifference has been theoretical to date—and the opportunity to test the extent to which these utilities are empowered to find creative solutions and efficiencies in identifying interconnection upgrades.

To facilitate this solution, Staff proposes the following:

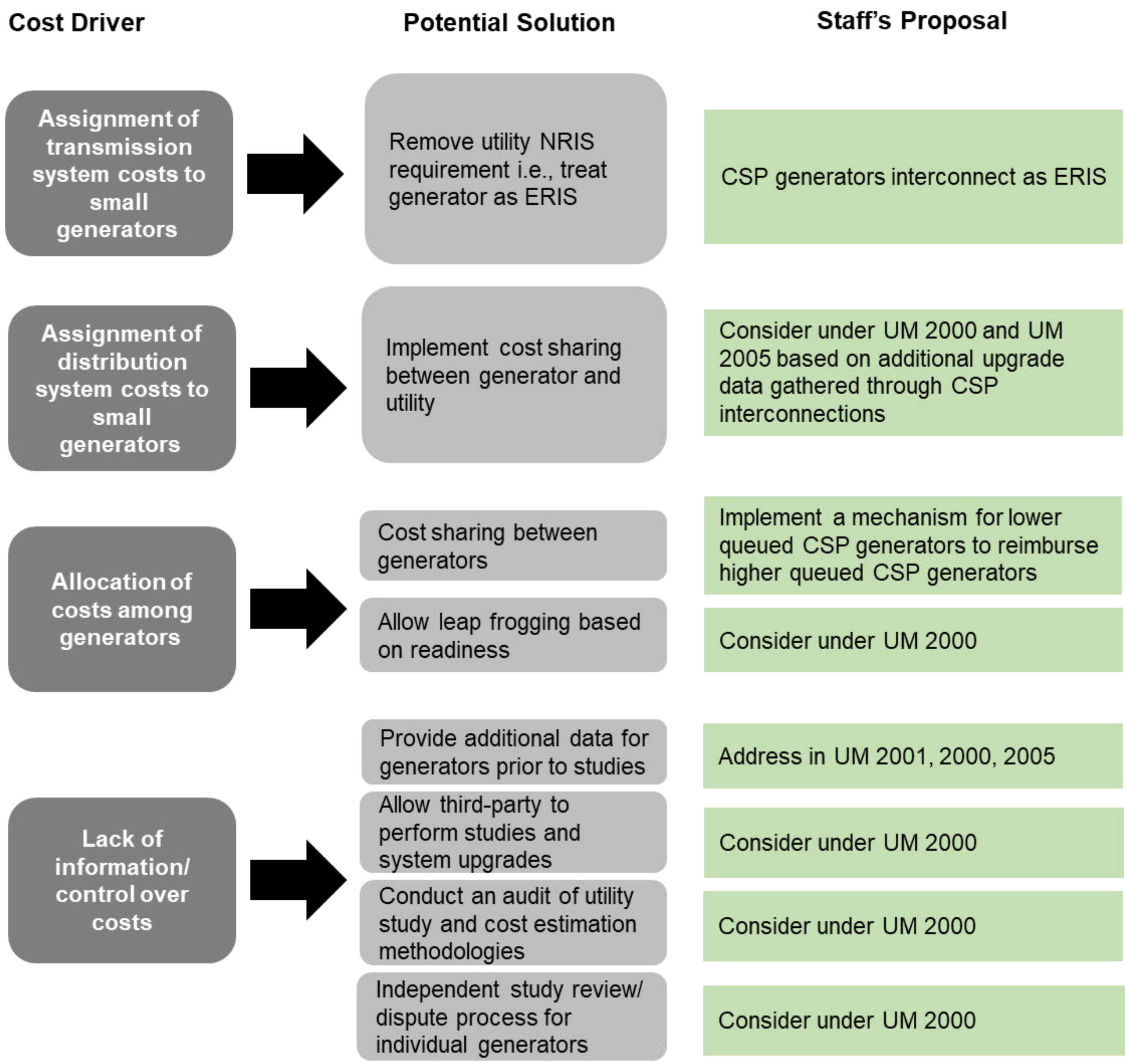
Addressing cost barriers: Adopt a new rule within the SGIP specifying the cost allocation for CSP project interconnections.

- Transmission upgrades: The generator will interconnect as an energy resource. To the extent there are necessary upgrades to the utility's transmission system (at and past the point of interconnection) as part of the utility's procurement of transmission service, the costs will be allocated subject to the utilities' Open Access Transmission Tariffs.
- Distribution upgrades: The utility will implement a cost-sharing mechanism for distribution system upgrade costs (at and past the point of interconnection) between CSP projects. The first CSP project triggering an eligible upgrade would initially bear 100% of the cost of the upgrade, less the upgrade allowance. Subsequent CSP projects benefiting from that upgrade to the distribution system will reimburse the first CSP project commensurate with the project's utilization of the available capacity created by the upgrade.
- The CSP-specific SGIP rule (CSP rule) described above is intended as a time-and-capacity-limited pilot. Unless the Commission chooses to extend the rule, the utility will accept interconnection applications under the CSP rule for 18 months following the rule's adoption or until the aggregate capacity (MWac) of generators with an executed CSP interconnection agreement that have received pre-certification equals the utility's capacity tier (2.5 percent of 2016 system peak load), whichever comes first.
    - Generators seeking to interconnect under the new CSP rule will execute an interconnection agreement with the utility that is contingent upon the project receiving pre-certification in the CSP.
    - If the generator does not receive CSP pre-certification, it can withdraw from the interconnection queue or execute an interconnection agreement with the utility subject to the existing SGIP. The generator will be responsible for the cost of additional studies and upgrades required to interconnect under the existing SGIP.

  - If a CSP generator has executed an interconnection agreement under the CSP rule, but has not received CSP pre-certification before the aggregate capacity of CSP generators with an executed CSP interconnection agreement that have received pre-certification equals the utility's capacity tier, the generator may choose to retain its interconnection agreement under the CSP rule for 18 months to allow for pre-certified projects to withdraw from the CSP pre-certification queue. Or, the generator can execute a new interconnection agreement with the utility under the existing SGIP, subject to the same requirements to bear the cost of additional studies and upgrades required to interconnect under the existing SGIP.
- Staff will work with the utilities to closely track the type and amount of upgrade costs borne by ratepayers and the impact on the firm delivery of the QFs' generation to network load to inform UM 2000 and UM 2005.

Addressing timing barriers: With respect to delays performing interconnection studies, Staff proposes the Commission require all utilities to file a plan to address the backlog of studies with the Commission. This is particularly acute barrier for PacifiCorp, but Staff finds that it will benefit CSP generators across utilities. Staff proposes that each utility file a summary of outstanding interconnection studies and forecasted timeline to process the studies with the Commission, by September 1, 2019.

Figure 3: Summary of Staff's initial proposal



Next steps

Staff proposes a path forward that balances the urgency of the CSP launch timeline with the need to refine this proposal with stakeholders. First, Staff will hold a stakeholder workshop on July 17 2019 in the OPUC Hearing Room in Salem. The purpose of the workshop is to receive feedback on the proposed emergency rulemaking and outline remaining issues to be addressed. Workshop topics will include:

- Has Staff identified the appropriate barriers for CSP generator interconnections?
- Will Staff's proposal be fair and functional? Do stakeholders suggest any modifications, additions, or alternative solutions to address the interconnection barriers?

- What additional elements are required to implement the proposed solution? For example:
  - How does this solution apply to CSP generators that have executed an interconnection agreement or begun the interconnection study process with electric utilities?
  - Are screens or additional requirements needed to identify eligible generators?
  - Does this require modification of the existing interconnection process? For example:
    - Is a separate tier or queue required to implement Staff's proposal?
    - Would CSP need anything different than the standard pre-application study available to all generators?
  - Which upgrades should be eligible for the cost-sharing mechanism?
    - Should there be a minimum cost for an upgrade to be eligible for the cost-sharing mechanism?
  - How will generators confirm they are CSP projects?
  - How does the emergency rulemaking align with PACs efforts to address its net-generation issue for all generators seeking interconnection?

Stakeholders may provide written comment to UM 1930 in advance of the workshop. Staff requests that Stakeholders file written comments by July10, 2019.

Following the workshop, Staff will consider stakeholder's written and oral feedback and propose that the Commission open the emergency rulemaking at a public meeting in August or September.

Working with the PA and utilities, Staff will facilitate the implementation of the CSP interconnection rule and report back to the Commission on the impact of the tier on both ratepayers and the successful launch of the CSP.

Attachment A

DEPARTMENT OF JUSTICE
INTEROFFICE MEMO

DATE: January 31, 2019

TO: Caroline Moore

FROM: Stephanie S. Andrus

SUBJECT: CSP Projects as QFs

This memorandum addresses whether a Community Solar Program Project (Project) must be a qualifying facility (QF) under PURPA in order to participate in Oregon's Community Solar Program (CSP). Under the Commission's rules, Projects of non-electric companies should be QFs to facilitate the Commission's jurisdiction over sale of the unsubscribed portions of these Projects' generation.

Under the Federal Power Act (FPA), the Federal Energy Regulatory Commission (FERC) has jurisdiction of wholesales of energy for resale in interstate commerce and states have jurisdiction of all other sales, including retail sales of electricity to end use customers.[17] However, FERC has shared with states its authority over wholesale sales under the Public Utility Regulatory Policy Act (PURPA). PURPA requires utilities to purchase energy and capacity offered by qualifying facilities (QFs). The state is authorized to establish the rate for these purchases as well as terms and conditions of the sale.

ORS 757.386 requires the Commission to implement a community solar program that allows an electric company's retail customers to subscribe or own a portion of a solar project located in the electric company's service territory and receive a bill credit for their share of the project output transmitted to the electric company. The Commission has adopted rules to ensure transactions between electric companies and Project Managers and electric companies and participants under ORS 757.386 are subject to Commission's jurisdiction.

First, the Commission's rules require the electric companies to allow participants to virtually net meter and receive bill credits for the participants' proportionate shares of a Project's generation. Net metering is a retail transaction so the Commission is authorized to establish the bill credit rate and other terms of the transactions.

[17] 16 U.S.C. §824.

Second, the Commission's rules allow a Project to sell unsubscribed generation via a PURPA sale, if the Project is not an electric company However, it is likely that not all of a Project's output will be subscribed or owned by a CSP participant, at least not consistently throughout the life of the Project. Accordingly, the Commission has adopted rules addressing the disposition of the "unsubscribed" portion of Project output. OAR 860-088-0140 provides:

(1) Upon project certification, the project's remaining unsold and unsubscribed generation is eligible for sale subject to the following requirements:

(a) Upon request, an electric company must enter into a 20-year power purchase agreement with a pre-certified project to purchase the project's unsold and unsubscribed generation on an "as available" basis subject to the requirements of the Public Utility Regulatory Policy Act (PURPA) and ORS 758.505, et. seq.;

(b) If the electric company is the Project Manager, the electric company may seek Commission approval to recover from all ratepayers the "as available" rate for the project's unsold and unsubscribed generation; and

(c) Renewable energy certificates associated with generation sold under section (1)(a) of this rule at the "as available" rate will not transfer to the electric company unless otherwise agreed by the Project Manager and electric company.

(2) The value of any project generation that is not sold to or subscribed by participants, sold to an electric company under a power purchase agreement, or sold on another basis must be donated to the electric company whose service territory encompasses the project at the "as available" rate and used by the electric company to assist low-income residential customers' participation in the Community Solar Program.

Under subsection (1)(a), the unsubscribed output is sold to the electric company at the electric company's "as available" avoided cost rate. The transaction is a wholesale sale. The Commission's ability to establish the rate for a wholesale is limited to its authority granted under PURPA. Accordingly, the Commission's rule requiring that electric company's purchase unsubscribed output at the Project's request at the as available avoided cost rate is predicated on the assumption the Project will be a QF and eligible to make sales under PURPA.

Subsection (1)(b) addresses the disposition of the unsubscribed output when the Project is an electric company Project. Under subsection (1)(b), the electric company can use the unsubscribed portion to serve its retail customers, but must charge its retail customers the "as available" rate. The transaction at issue is a retail sale and therefore the Commission is authorized to establish the rate for without relying on its authority under PURPA. Accordingly, an electric company does not have to be a QF in order to participate in the CSP.

Subsection (2) provides that unsold and unsubscribed output must be donated to the electric company's low-income residential customers' participation based on the as-available rate. As already noted, the Commission does not have authority over wholesale transactions unless they are PURPA transactions. Accordingly, to effectuate the Commission's rule regarding donation of unsubscribed output at the as-available rate, the Project must be a QF.

Subsections (1)(a) and (1)(b) have permissive language that seems to provide Projects with optionality regarding the disposition of unsubscribed energy. Subsection (1)(a) provides "[u]pon request, an electric company must enter into a 20-year power purchase agreement with a pre-certified project" for the unsubscribed output. Subsection (1)(b) provides that an electric company "may" sell unsubscribed output to its retail customers.
Although OAR 860-088-0140 does not expressly limit Projects to the specified options for the disposition of the unsubscribed output, the rules are appropriately interpreted to exclude any other options.

The as available rate for unsubscribed output is intended to incent Project Managers to obtain subscriptions or sales of as much of the Project as possible. Staff initially proposed a rule providing that a Project could not be certified unless 90 percent of it was subscribed or owned by CSP participants. Eventually, Staff agreed to propose, and stakeholders supported, a rule with a 50 percent subscription/ownership requirement based on the fact the as available rate for the unsubscribed portion was sufficient to incent maximum subscriptions and sales of Project shares. The Commission adopted the Staff proposal and the underlying rationale:

> The proposed rules require that 50 percent of the total capacity of a project be subscribed before the project can receive final certification. With respect to the remaining unsold or unsubscribed portion, the proposed rules allow the project to sell up to 10 percent at the "as available" Public Utility Regulatory Policy Act (PURPA) rate.
>
> Staff advocates in its final comments that a minimum subscription of 50 percent achieves a balance between allowing flexibility for developers and ensuring that projects are actually subscribed. Stakeholders counter that limiting the sale of unsold or unsubscribed generation to the "as available" PURPA rate is a sufficient incentive to drive project managers to maximize participation. They further caution that the proposed 10 percent limit adds a significant, unnecessary burden to project financing and development.
>
> ***Resolution:*** We adopt the minimum subscription of 50 percent as a reasonable balance of the competing interests and goals underlying this provision. We remove the 10 percent limit on the sale of unsold or unsubscribed generation. Based on the comments that the "as available" PURPA rate is a sufficient incentive to maximize participation in the projects, we find the provision unnecessary.[18]

[18] In the Matter of Rules Regarding Community Solar Projects (AR 603), Order No. 17-232 (2017 WL 2839877, p. 6.).

It may be possible for the Commission to design a CSP in which a Project has the option to either sell unsubscribed generation at wholesale to electric company under PURPA, and subject to jurisdiction of the Commission, or not under PURPA, and subject to FERC's jurisdiction. While the Commission may be able to compel electric companies to enter into non-PURPA PPAs with electric companies,[19] the Commission would not be able to establish the purchase price or other terms of the sale.[20]

However, if the Commission were to amend its rules to allow Projects to sell unsubscribed generation at wholesale subject to FERC jurisdiction, Staff should consider recommending that the Commission amend the rules to maintain the incentive to subscribe as much of the Project as possible. For example, the Commission could amend the rules regarding certification to require a percentage higher than 50% be subscribed before the Project can be certified.

[19] See Entergy Nuclear Vt. Yankee, LLC, Shumlin, 733 F.3d 393, 417 (2d Cir. 2013) ("[S]tates have broad powers under state law to direct the planning and resource decisions of utilities under their jurisdiction.")

[20] It is not clear whether the length of such a PPA is within the state's authority as part of a resource acquisition requirement or whether the length is exclusively a matter subject to FERC's jurisdiction as a term of a wholesale sale.

Attachment B

Excerpt from UM 2000 April 5 – Workshop Notes

Issues related to interconnection for QFs:

Interconnection

- Utility-Developer Interaction
    - Better communication between developer and utility engineer
    - Studies – ability to: audit, self-perform, challenge, discuss
    - NR eligibility – Audit – Self perform
    - Interconnection – need customer right to self-perform studies, builds with quality vendors
    - Studies – ability to: audit, self-perform, challenge, discuss
    - Study – Inputs develop interconnection, right to have so can validate
    - Third party studies and construction
    - Access to previous studies
    - More transparency access to data
    - Additional transparency
    - Transparency – access to data – study data - regs
    - Analytics – history on how process is working
    - Data on study process – audit/analyze
    - Third party engineering firm allowed to review substance of interconnection report
    - Communication with engineers
    - Requirement that studies receive stamps
    - Timing of requests in relation to purchase contracts
    - Sources of utility cost assumptions
- Overall Process
    - No response obligation for utilities – silence!
    - Network upgrade costs as a means to burden QF interconnection
    - Who pays for network upgrades vs customer indifference education
    - Education on difference between interconnection and transmission
    - Requirement for back and forth on interconnection study report
    - Timing of advance payments, refunds for overpayments
    - Interconnection options fundamental options
    - Remedy if utility is short-staffed
    - Utility Staff for interconnection studies (why delay? Short staffed?)
    - Enough information to verify study results
    - Process – barriers in implementation
- Classification
    - Special QF process – NR resource
    - The requirement that QFs take NRIS
    - #1 NR requirements for QF PPA eligibility is garbage not consistent with variable resource
      $$$
    - Requirement to identify as QF (or not) at beginning of process
    - Inordinately high costs of network upgrades without sufficient technical justification
    - Prompt payments
    - Appropriate cost assignment for upgrades
- Other
    - AR 521 language – third party contractor reschedule

- IOU RFPs use interconnection bid criteria to exclude RFP participation – ratepayers screwed
- Interconnection queue issues deny ratepayers competitive options QFs RFP bidders
- Transmission – utility claim conditional firm isn't long-term firm
- Education
- Real-time communication (SCADA) data
- Data protection cyber/physical security issues

- Oversight
  - No consequences for utility bad behavior
  - Education difference between open access policies and PURPA policies
  - Utilities not making schedule – studies – tariff – builds
  - Conflicts between PPA and interconnection agreements
  - PPA and interconnection agreements interaction
  - Changes to PPA COD due to delays
  - Need more strict requirements for utilities to follow timelines.
  - Enforcement of existing rules
  - Utility penalties on utility for failure to complete interconnection
  - Publication of interconnection study requirements
  - Utilities need to comply with rules
  - Lack of effective dispute resolution
- Queue
  - Lack of movement by PAC in processing the IC queue
  - Keeping queue up to date
  - Education on serial queue order interconnection process requirements for QFs and non-QFs
  - Make load queue public (load vs generation effects) study outcomes
  - Education appropriate use of publicly available interconnection data
- Load Pockets
  - Exist? Load pockets
  - "Load pockets"
  - Queue and load pockets
  - Education on load pockets
  - Customer indifference in constrained areas
  - Responsibility to locate project
- State – federal guidelines
  - Entire QF-specific interconnection study construct is bogus (vs FERC OATT)
  - Comparison of current OATT tariff – policy different from federal mandate
  - What rules/guidelines apply to 10-20 MW projects?
  - Use of "QF interconnection process/rules" artificial barrier to evade PURPA
- Costs
  - No cost sharing
  - Cost allocation responsibility
  - Lack of refunds for network upgrades
  - Cost
  - Lower cost equipment alternatives
  - Cost – What – How much

- Other
  - Informal technical dispute advisory board of industry representatives like OJUA
  - Mini focused issue workshops
  - Option put all options on the table
  - Communication

Purpose

This proposal outlines the recommendations for three policy decisions required to implement Oregon's Community Solar Program (CSP). Specifically, this proposal includes recommendations for 1) unresolved low-income program requirements, 2) the transition between start-up and ongoing costs, and 3) the bill credit rate. The issues covered in this draft proposal are the remaining portion of the four policy issues that the Commission must address prior to CSP implementation. Staff released its draft proposal for the first issue, CSP interconnection requirements, on June 19, 2019.[1] All four policy recommendations are made by Oregon Public Utility Commission (OPUC) Staff and informed by the CSP Program Administration Team (PA Team). This team is comprised of the Program Administrator (PA) and the Low-Income Facilitator (LIF).

The timeline and process for Stakeholder participation in these policy decisions is provided below. This draft proposal is intended to give interested parties additional time to prepare comments prior to the release of final Staff recommendations on October 4, 2019. As noted below, Stakeholders can provide initial comments prior to October 4th if desired; however, Staff may not be able to incorporate those comments into its final recommendation.

Date	Activity
Friday, September 13, 2019	Staff previews the PA Team's proposal for bill credit, transition between start-up and ongoing, and low-income program policy issues, to provide Stakeholders sufficient time to develop comments on the October 1, 2019 memo.
Friday, October 4, 2019	Staff Memo with final recommendations for interconnection, bill credit, transition between start-up and ongoing, and low-income program policy issues.
Tuesday, October 15, 2019	Deadline for Stakeholder written comments on Staff memo. **Please note:** Stakeholders can submit initial comments in advance of the October 4th proposal and final comments by October 15th if desired. Staff may not be able to incorporate initial comments into its October 4th final recommendations.
Tuesday, Oct. 22, 2019	Regular Public Meeting: Staff presents final policy recommendations and Stakeholders have the opportunity to comment.
Tuesday, Oct. 29, 2019	Special Public Meeting: Commission deliberate and decide policy issues.

Questions and comments can be directed to:

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Natascha Smith, natascha.smith@state.or.us, (503) 559-7752

[1] See Docket No. UM 1930, Staff's Draft proposal for Community Solar Interconnection, June 19, 2019. https://edocs.puc.state.or.us/efdocs/HAH/um1930hah13520.pdf

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Background

On June 29, 2017, the Commission adopted administrative rules for the CSP.[2,3] To account for continued learnings and insight from the to-be-selected PA and LIF The Commission recognized that certain program decisions would be best resolved later in the implementation process.. While the Staff is working with the PA Team to propose solutions for the majority of outstanding decisions in the program implementation manual (PIM), certain issues are significant and complex enough to warrant a separate Commission decision process. Decisions related to all four policy areas are critical inputs for Project Managers to prepare projects for pre-certification and must be resolved prior to pre-certification launch, which is scheduled for December 2019 (See Figure 1).

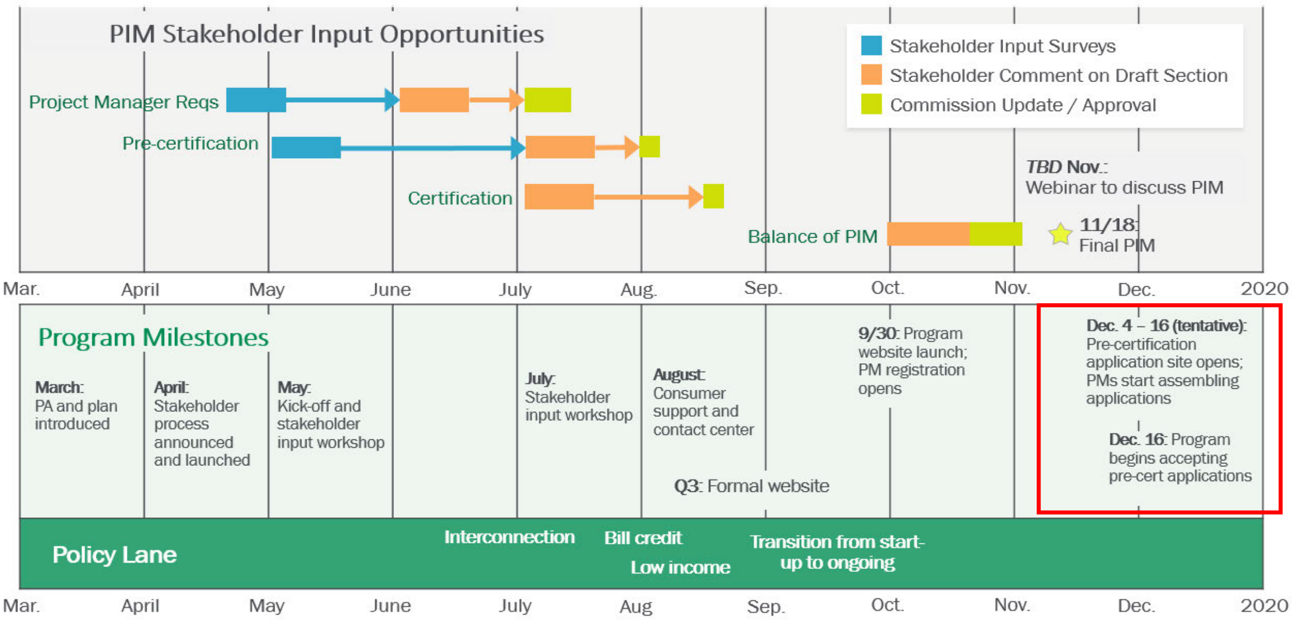
As noted in Staff's amended UM 1930 CSP implementation schedule, released August 23, 2019, the four policy issues addressed separately from the PIM include:

1. Interconnection: solutions to ensure that CSP interconnections are fair and functional.
2. Bill credit
    a. Implementation of the Simple Retail Rate
    b. Transition after the interim capacity tier
3. Low-income participation requirements
    a. Minimum eligible low–income participants per project (%)
    b. Requirements for low–income participation fees
    c. Definition of eligible low-income participant
4. Transition between start-up and ongoing costs
    a. Transition point
    b. Administrative fee methodology[4]

On June 19, 2019, OPUC Staff released a draft proposal related to CSP interconnections. This proposal addresses the remaining three policy areas. On October 4, 2019, the Staff will bring the four policy decisions together into a final recommendation for the Commission. Stakeholders will provide written comments on the final Staff's recommendation by October 15, 2019. Staff will present its final policy recommendations at the October 22, 2019 Regular Public Meeting. Stakeholders have the opportunity to comment at the Regular Public Meeting, and the Commission will deliberate and decide on the four policy areas at a Special Public Meeting on October 29, 2019.

[2] *See* Oregon Administrative Rules Division (OAR) 860, Section 88.
[3] *See* Docket No. AR 603 In the Matter of Rules Regarding Community Solar Projects, Commission Order No. 17-232, June 29, 2017.
[4] See Docket No. UM 1930, Staff's amended schedule, August 23, 2019.

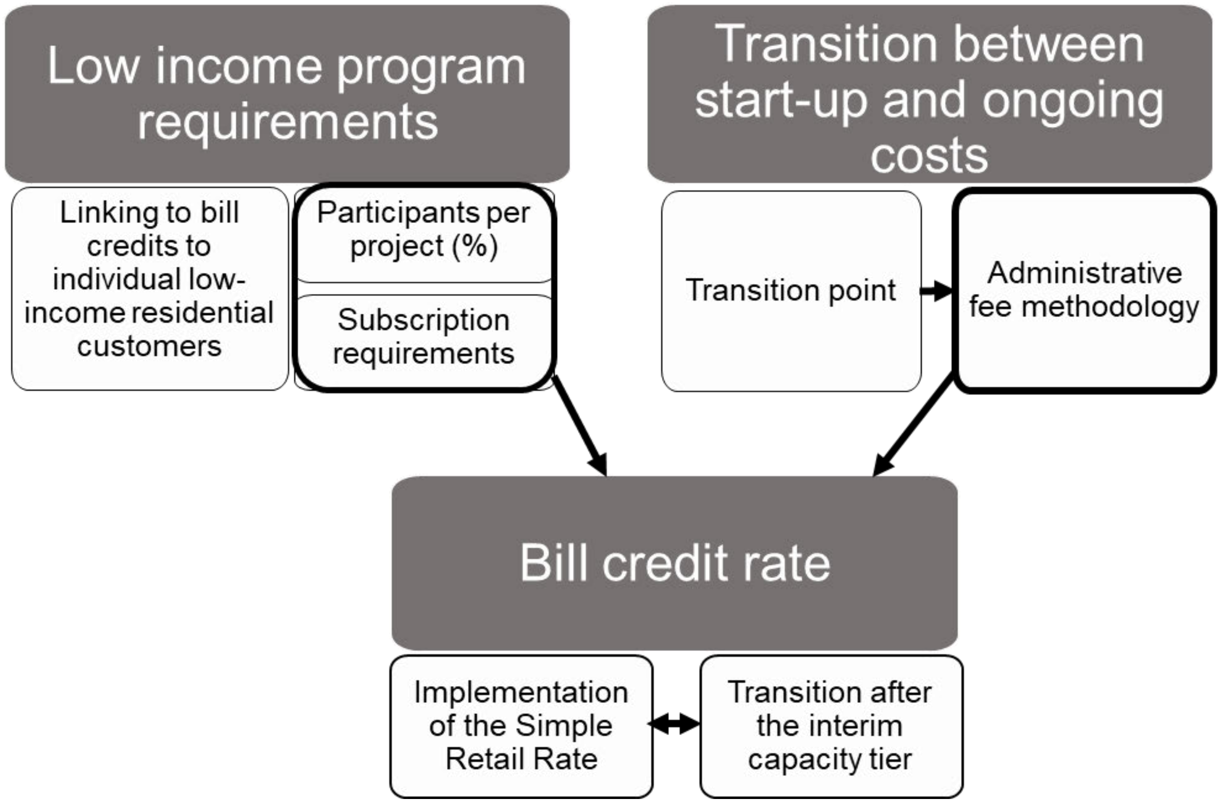
Figure 1 CSP Program Launch Timeline



Proposal Framework

The policy areas addressed in this Staff proposal are interrelated. Specifically, certain policy recommendations related to low-income requirements and the transition between start-up and ongoing costs are required inputs into Staff and the PA Team's bill credit rate analysis. Therefore, Staff's proposal provides recommendations for those two policy areas first, then incorporates the recommendations as assumptions in the bill credit rate analysis. Attachment A of this proposal provides several sensitivities to capture any the impact Staff's proposals for low-income requirements and the transition between start-up and ongoing have on the bill credit analysis.

Figure 2 Summary of Policy Issues and Interactions Addressed in Staff's Proposal



Staff's analytical framework uses the following steps across all three policy areas addressed in this memo:

1. Articulate decision making criteria (e.g. baseline required CSP outcomes).
2. Identify the potential solutions that balance program outcomes.
3. Assess trade-offs across solutions.
4. Consider additional recommendations to maximize CSP outcomes.

The following sections will outline Staff's proposed decision-making principles, analysis, and policy recommendations for each issue.

Proposed decision making principles

While the legislature did not provide an overarching goal of the CSP program, it offered the following guidance to the Commission in establishing rules for the CSP:

- Incentivize electricity consumers to be owners or subscribers;
- Minimize the shifting of costs from the program to ratepayers who do not own or subscribe to a community solar project;
- Where an electric company is the project manager, protect owners and subscribers from undue financial hardship; and
- Protect the public interest.[5]

[5] Oregon Revised Statute (ORS) 757.386(2)(a).

Given these directives, Staff has proposed a decision-making framework that will promote Staff's understanding of the overarching purpose of this program, while balancing additional required program outcomes. These elements are descried below.

Overarching purpose – equitable opportunity

Staff proposes that the overarching objective of the CSP is to establish parity for consumers that have not been able to access solar customer generation opportunities and incentives.

Staff has thought at length about the role that CSP plays in the landscape of utility resource development and consumer options. Based on the direction from the legislature, and the Commission's mission and values, this consideration has focused on the unique costs and benefits that CSP projects provide ratepayers. As stated by the legislature, CSP projects create a new opportunity to share the costs and benefits associated with solar generation.[6] While ratepayers have always shared in the costs and benefits of utility-owned or contracted solar, this program model allows a wider and more diverse set of ratepayers to experience the direct benefits of distributed and self-generation that the majority ratepayers historically could not access for geographic, economic, and other reasons.[7]

Staff also recognizes that CSP electricity generation is more expensive and requires incentivization above what ratepayers pay for other small generators, such as Qualifying Facilities, and market rate solar PPAs.[8] For example, comments submitted by Oregon Solar Industries Association and the Coalition for Community Solar Access state that,

> [T]here 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.[9]

Given the level of cost and risk placed on all ratepayers to stand up the CSP, Staff finds that CSP is best used as a tool to broaden participation in direct solar generation opportunities, but not as a vehicle for the acquisition of least-cost, least-risk resources. Additionally, Staff finds that CSP design is a valuable tool to prevent underserved communities from being left out of solar generation opportunities, but is not a particularly efficient means to relieve energy burden relative to mechanisms such as direct bill assistance and weatherization.

With this in mind, Staff believes that the CSP program design should focus on creating more equitable access to self-generation opportunities, including the incentives currently enjoyed by a relatively small portion of ratepayers. While all ratepayers have funded customer generation

[6] Oregon Revised Statute (ORS) 757.386(1)(a).
[7] Some of the major barriers to solar generation access in Oregon are described in Strategies for Increasing Solar Deployment in Oregon's Low- to Moderate-Income Communities. https://lmisolaroregon.files.wordpress.com/2018/06/oregon-lmi-solar-strategies.pdf.
[8] Residential retail rates across the utilities are approximately \$0.08-\$0.11/ kWh. Pricing from recent utility solar acquisitions, such as Idaho Power, and industry data related to trends in solar PPA costs, such as LBNL and Lazard, place solar PPA rates between \$0.02-\$0.05/kWh. This suggests that utilities could acquire four or more times as much solar generation for the same cost as CSP at the interim bill credit rate discussed further in this report.
[9] See Docket No. UM 1930 comments submitted by OSEIA/CCSA on March 3, 2019, p.5.

incentives for decades, both as tax payers and utility customers, these opportunities have only been accessible to financially and geographically well-positioned property owners participating in net metering.[10] With CSP, the state has the opportunity to provide a comparable opportunity to the majority of households that have paid into these incentive programs, but not had the resources or opportunity to participate (See Table 1).

Table 1 Comparison of existing customer solar generation and CSP Capacity Tier

	Net Metered Solar in Oregon – most recently reported installed capacity (MW)	Community Solar Capacity Tier (MW)
IDP	1.15[11]	3.27
PAC	65.06[12]	64.60
PGE	76.31[13]	93.15
TOTAL	**142.52**	**161.02**

Additional requirements

As a complement to equitable access, Staff finds that the CSP must balance the following minimum requirements.

- **Low-income accessibility:** The CSP's low-income participation targets are directly linked to the notion of equitable opportunity. To meet the program's low-income targets in a way that provides meaningful opportunities for low-income participants, Staff proposes a minimum expectation that CSP participation makes low-income participants economically better off. This means the net impact of participation must result in a decrease of low-income participant bills but for CSP participation, both month-over-month and over the life of a CSP subscription.
- **Project availability**: Equitable opportunity also requires the market to produce CSP projects in which interested consumers can participate. Therefore, Staff identified minimum conditions for CSP project development, including consideration for projects that are driven from within the communities served by CSP. These conditions include:
  - Project Manager value: Staff understands that Project Managers must meet a minimum threshold for anticipated financial returns to move forward with project development. The PA Team worked with a range of solar developers and community-based organizations to review proprietary community solar pro formas and financial analyses. Based on this insight, the PA Team identified an 8% developer internal rate of return (IRR) as a proxy for project development.

[10] Incentives referenced include, but are not limited to, net metering credits, Oregon's residential and business energy tax credits, public purpose charge incentives, the volumetric incentive program, federal investment tax credits, and the 2019 Oregon House Bill 2618 solar rebate program.
[11] *See* Idaho Public Utility Commission Compliance Filing in Case No. IPC-E-12-27 Annual 2018 Net Metering Status Report, April 23, 2018, p. 2.
[12] *See* RE 39 – 2018 Net Metering Report for Oregon, Docket No. RE 39, April 1, 2019.
[13] *See* PGE's Division 39 Net Metering Annual Report, Docket No. RE 45, March 29, 2019.

- Project Manager certainty: Project Managers and lenders require a minimum level of certainty about key financial drivers in order to assume the upfront costs and risks to prepare a project for pre-certification. Staff's analysis assumes that Project Managers, at minimum, need to understand the likely range of bill credit rates and administrative fees that the PA will assign to the project. Certainty includes both the ability to anticipate the rate that the project will receive without knowing the project's place in the pre-certification queue, and the value of that rate over the life of the project.
- Community-driven project certainty: CSP projects led by non-profits, local governments, and other community-based organizations (CBOs) may take longer to prepare for pre-certification than professional solar developers. These projects may also be less equipped to tolerate risk when making investments ton move projects toward pre-certification. Therefore, Staff finds it particularly important to ensure Projects Managers have certainty about key financial drivers further down in the pre-certification queue.

- **Ratepayer value:** Finally, these policy choices must represent the lowest cumulative ratepayer impact at which the other program requirements are achieved. CSP is one of a growing number of pilots, programs, and investments driven by the State's evolving needs and goals. Staff finds it important to consider the impacts of CSP in this context. Staff recognizes that there are costs required to stand up a successful program, but they must be balanced with the risks of over-incentivizing CSP and targeted to costs that will maximize ratepayer's return on this investment. For example, there are one-off investments that can reduce ongoing administrative costs e.g. automating the CSP Software Platform, reduce project soft costs, or remove other barriers to project development. Policy decisions should consider whether these upfront investments net a value for participants by reducing the need for long term bill credit rate incentives or accelerating the timeline in which the program is large enough to sustain its administrative costs without ratepayer support.

Analysis—Low-income program

Background on low-income program

ORS 757.386(9) requires that the Commission determine a methodology by which 10 percent of the total generating capacity of the community solar projects operated under the program will be made available for use by low-income residential customers of electricity. Further, the legislature directed the Commission to periodically review and adjust this percentage. When adopting the CSP rules, the Commission identified several important implementation issues related to the 10 percent low-income participation target, but recognized the need to bring the LIF on board to inform these decisions. Specifically, the Commission noted the following:

> To allow flexibility to continue to evaluate how to implement this important component of the program…we modify the definition of low-income residential customer to indicate that we will later establish an eligibility threshold for these customers. We require under any implementation system, that the bill credits associated with the 10 percent allocation be linked in some direct manner to the electricity usage of individual low-income residential customers.
>
> We adopt by order the requirement in the proposed rules that at least five percent of each project must be allocated for use by low-income residential customers, and at least an additional five percent of the total program must be allocated to serve

> low-income residential customers. We recognize, however, that determining how to implement this important component of the program is challenging and will likely require further deliberation and input from the entities selected as program administrator and low-income facilitator...
>
> Recognizing that financial incentives may prove appropriate or necessary to achieve the goal of participation of low-income residential customers, we add a new section providing that we may find cause to establish a funding mechanism to support the participation of low-income residential customers.[14]

Beginning in April 2019, the LIF engaged a broad range of experts to develop a low-income strategy that will meet the state's targets in a meaningful way. The PA Team has carried this strategy forward to propose answers to the key implementation questions described by the Commission above. The comprehensive low-income policy proposal from the PA Team is found in Attachment C and summarized with Staff's proposal below.

The minimum percentage of total project capacity that must be allocated for use by eligible low-income customers.

Since the Commission adopted the CSP rules, Staff and the PA Team's understanding of CSP economics, and the ratepayer support required to stand this program up, have evolved. This includes concerns that Project Managers will struggle to secure financing unless the bill credit rate is incentivized so that it's a guaranteed savings product for all participants.[15] Staff finds it increasingly important to ensure low-income and traditionally underserved populations have broad access to these savings products, and equitable opportunity to receive the associated incentives. If an incentive rate will only be available on an interim basis, Staff finds it particularly important to ensure that the program's low-income participation targets are prioritized during this period.

Staff recognizes that the low-income target could be met in two ways: 1) a minimum ten percent requirement per project, and 2) a mix of projects that meet and exceed the five percent per project requirement adopted by the Commission to date. The former places risk on Project Managers and the LIF to recruit interested participants with meaningful opportunities. The latter places risk on ratepayers and/or other outside funding sources to incent Project Managers to voluntarily exceed the minimum per project requirement.[16]

> **Recommendation:** Given the CSP's focus on providing financial benefits for all participants, it is imperative that Project Managers and other participants bring underserved communities along fully, and from the beginning. Therefore, Staff recommends a minimum 10 percent of each CSP project's nameplate capacity must be allocated exclusively for use by low-income residential customers. After pre-certification opens, the PA Team will gather data from CSP projects and monitor the performance of the CSP market. Staff can work with the PA Team to recommend an alternative per project or program goal if it determines that a different per-project amount can balance low-income accessibility and project availability at a lower cost to ratepayers.

[14] Order No. 17-232, p. 11.
[15] For example, see OSEIA-CCSA Comments filed by Charlie Coggeshall, March 2, 2018, p. 6.
[16] The PA Team is aware of potential funding sources such as the Portland Clean Energy Fund and Portland General Electric's development funds. However, the PA Team is concerned about their geographically limited nature and does not have a clear understanding of the amount of additional low-income participation these funds will drive.

The minimum expectation for financial incentives associated with eligible low-income participation.

On July 3, 2019, the PA Team posted the draft Project Requirements PIM section for comment through the CSP stakeholder engagement site.[17] This section included a requirement that Project Managers design low-income subscriptions such that participants do not experience a net increase in utility bills due to their participation in the program. In other words, the sum of the subscription/ownership costs (participation fees) and administrative costs cannot exceed the value of the bill credit. This recommendation aligns with the proposed principles of equitable access and low-income accessibility.

In the draft PIM, the PA Team flagged that additional requirements for the financial benefits of eligible low-income subscriptions were under consideration. For example, the Project Manager must set the subscription or ownership fees for eligible low-income participants at least X% below the value of the bill credit rate. In the draft PIM, the PA Team did not discuss how this elevated incentive requirement should be funded.

Staff's consideration of minimum financial benefits is rooted in low-income accessibility. The LIF's research indicates that a 20 to 50 percent estimated bill reduction is a valuable tool to minimize recruitment costs and make the program meaningful—rather than tokenizing—for low-income participants. Further, the LIF's discussions with potential community recruitment partner organizations finds that, 1) a baseline financial structure will help clearly explain the program opportunity to potential participants; and 2) a meaningful level of financial benefit is required to ensure the LIF's recruitment partners and those experiencing low incomes can dedicate resources to considering CSP participation among their other competing priorities and commitments.

However, setting a specific financial threshold with the current level of uncertainty over project financials and low-income recruitment outcomes also creates substantial risk. Research suggests there is a delicate balance between the level of low-income participant benefit and the availability of low-income participation opportunities—or any participation opportunities.[18] If the minimum financial requirement is higher than is feasible for projects to bear, it could prevent Project Managers from bringing otherwise viable projects forward. This risk is even greater for community-based Project Managers that are likely to experience tighter margins and greater development risks. These projects may bring meaningful benefits to participants and added benefits of wealth building in underserved communities, but not quite reach the minimum financial benefit requirement.

While Staff agrees with the PA Team that a 50 percent subscription savings or greater is the preferred outcome for low-income financial benefits in the context of the CSP (See Attachment C), current financial models do not provide enough confidence that this is feasible (See Analysis—Bill credit rate and Attachment A.) Setting an infeasible minimum requirement poses a greater risk to both low-income accessibility and project availability, due to the difficulty and delays associated with course correction. Staff finds that it will be faster and more effective to course correct for low-income recruitment issues when there are projects moving forward with pre-certification and project data available. If the PA Team finds initial low-income interest is

[17] *See* Requirements Chapter under Previously Posted Chapters, https://orcsplaunch.wordpress.com/resources/

[18] National Renewable Energy Laboratory, Low-Income Community Solar: Utility Return Considerations for Electric Cooperatives, p. 4-5. https://www.nrel.gov/docs/fy18osti/70536.pdf

limited by the financial benefits offered by projects in queue, it can analyze the level of benefit currently offered and the project financial data collected through pre-certification to identify the appropriate solution. Further, if low-income interest is limited, Project Managers will have an incentive to sharpen their pencils to ensure they can meet the certification requirements tied to low-income participation.

With limited confidence that a 50 percent subscription savings is feasible, Staff and the PA Team identified the following alternative options. These options could be adopted until more insight and data are available through pre-certification:

- Generalize the minimum requirement to state that low-income participants must receive some level of subscription savings from participation;
- Reduce the minimum subscription savings to a level that it is feasible under the current program; or
- Adopt a low-income bill credit adder that makes the 50 percent subscription savings feasible e.g., the other way to make it feasible for Project Managers to set participation fees 50 percent below the bill credit rate, is to raise the bill credit rate.

Recommendation: As demonstrated in the Analysis—Bill credit rate section, Staff finds that a 20 percent subscription savings to participants is likely feasible under the current program design (the sum of monthly fees associated with CSP participation must be at least 20 percent lower than the value of the bill credit rate). Staff recommends that the Commission adopt this 20 percent subscription savings requirement with the following additional requirements:

- The PA Team will list a 50 percent or greater subscription savings as a best practice in the PIM and CSP Project Manager training materials.
- The LIF will prioritize Project Managers with a 50 percent or higher low-income discount for low-income participant placement.
- Project Managers with a 50 percent or higher low-income discount will qualify for the Low-Income Project Designation.[19]
- Once pre-certification opens, the PA Team will monitor the actual subscription discounts offered by Project Managers applying for pre-certification and the relationship between low-income recruitment and financial benefit. The PA Team will work with Staff to assess whether additional financial benefits are required to facilitate low-income participation, how those can be achieved/funded, and, based on low-income participation data and project financial data, the appropriate level to set minimum low-income financial benefit.

Attachments A and C provide additional analysis of a low-income bill credit adder that could mitigate the risks associated with a 50 percent minimum threshold. Staff does not have enough certainty around project availability to recommend this additional ratepayer expense at this time.

[19] *See* draft PIM Requirements section, p. 9, posted July 3, 2019. https://orcsplaunch.files.wordpress.com/2019/07/pim-chapter-x-requirements.pdf.

Due to the difference in bill credit rate across utilities and the diverse range of potential project designs, Staff recognizes that the net benefit requirement may still be difficult for some Project Managers. To mitigate this and facilitate the ability to comply with the best practice subscription discount recommended above, Staff also recommends that eligible low-income participants be exempt from ongoing PA fees. Rather, these PA fees will be absorbed by the other program participants and/or Project Managers. Staff proposes this as a streamlined mechanism to improve the economics of low-income subscriptions that is socialized across all program participants equally. The PA will monitor low-income allocated capacity during pre-certification to ensure that this model does not pose a risk of administrative fee under collection.

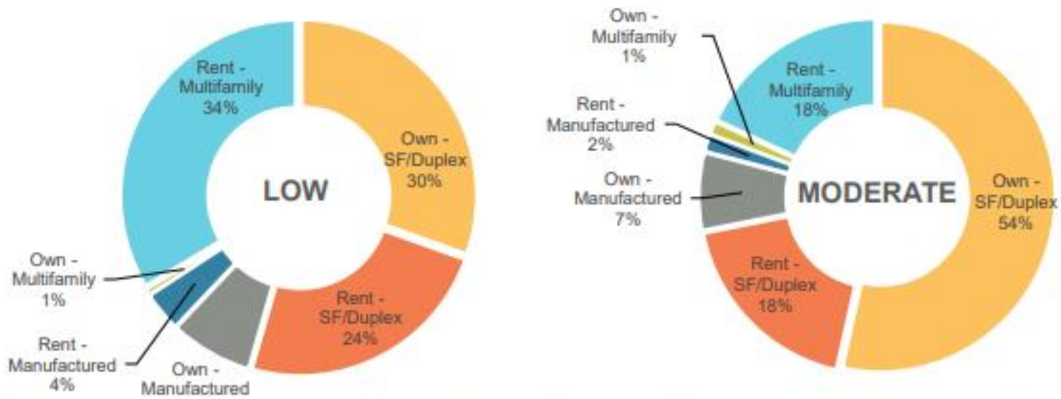
The manner in which bill credits must be linked to the electricity usage of individual low-income residential customers.

Providing equitable opportunity to diverse housing and income-types is a key benefit of the CSP. However, housing diversity adds complexity when ensuring that the eligible low-income households relied upon to meet the program's targets actually receive the benefits of the bill credit.[20] Because the entire CSP participant experience is managed on-bill, the Commission must determine eligibility if the housing provider holds the utility account on behalf of the tenant, and/or when the tenant's utility payment is included in computation of gross rent.[21] For example, U.S. Department of Housing and Urban Development (HUD) explains the arrangements that some rent-assisted housing units:

> Federal housing law directs that the resident's share of rent in federally assisted public housing should equal 30 percent of the household's adjusted monthly income. In interpreting the federal housing law, HUD has defined the Total Resident Payment for "rent" to include both shelter and the costs for reasonable amounts of utilities. The amount that a [Public Housing Agency] determines is necessary to cover the resident's reasonable utility costs is the utility allowance. Whether a household receives an allowance for a given utility service generally depends on the way the utilities are metered. Allowances are provided for individually metered or sub metered utilities, but not for master-metered utilities. [22]

[20]OAR 860-088-0080(2) requires that, "the respective bill credits associated with [the low-income] allocation must be linked to discrete low-income residential customers."
[21] Depending on the requirements of an affordable housing provider's funding and the household's income, any net decrease in electricity costs due to CSP participation may not be reflected in the residential consumer's housing costs.
[22] U.S. Department of Housing and Urban Development: https://www.hud.gov/program_offices/public_indian_housing/programs/ph/phecc/allowances.

Figure 3 Low and Moderate Income Housing Type Distribution in Oregon[23]



Source: American Community Survey 5-year Estimate, Census 2015 self-reported figures.

Staff identified three options to account for the complexity of affordable housing bill responsibility: 1) Change the requirement that low-income participation must directly benefit a low-income subscriber; 2) prohibit participation for affordable housing residents that do not directly pay their electric bills or receive a utility allowance; or 3) develop additional requirements for housing providers that hold eligible low-income subscriptions on behalf of residential households.

Staff finds that the first two options are in direct conflict with equitable opportunity and low-income accessibility. Further, Staff recognizes that affordable housing providers may serve as natural aggregators of interested low-income households, and can increase other low-income participant benefits by shouldering some of the burden of researching and committing to a CSP project.

> **Recommendation:** Rather than develop specific requirements for every possibility across the breadth of housing arrangements across the state, Staff proposes additional guidelines to ensure that bill credits and other benefits of qualifying low-income participation are linked to discrete residential participants regardless of the housing type. Staff proposes that an eligible low-income subscription can be held by:

- A qualifying residential customer as defined in the PIM, that meets the income requirements set forth in the PIM, in addition to all other Subscriber eligibility requirements.
  - A residential utility account holder is considered eligible if they are unable to directly monetize the bill credit because of a utility allowance or other requirements of rent-assisted housing. This avoids unfair accessibility limits and recognizes the possibility that the participant will enjoy community solar benefits if they move into a different housing type.
- An affordable housing provider that directly pays for the residential electricity costs of tenants with household incomes that meet the income and other eligibility requirements set forth in the PIM. These subscriptions stay with the

[23] Energy Trust of Oregon, Strategies for Increasing Solar Deployment in Oregon's Low- to Moderate-Income Communities. https://lmisolaroregon.files.wordpress.com/2018/06/oregon-lmi-solar-strategies.pdf.

housing unit. Tenants that move out of the unit, but wish to retain CSP participation, can work with the LIF to find placement in a new project or on the waiting list. To qualify as an eligible low-income subscription, the housing provider must:

- Identify to the LIF the low-income customers, by name and housing units, on whose behalf they are participating (the "low-income beneficiaries");
- Share at least 75 percent of any financial savings that result from the Subscription with the low-income beneficiaries;[24]
- Educate the low-income beneficiaries about community solar, the Project, how they benefit, and how to sign up with the Low-Income Facilitator for another Project if they move.

Staff recognizes that this treatment of affordable housing providers adds complexity to that PA Team's administrative responsibilities. And, that this recommendation leaves key implementation details to be determined, such as how housing providers can demonstrate that they have shared 75 percent of financial savings with tenants and how the PA Team will enforce it. This specialized support for a CSP element that many states find difficult is a key role of the Low-Income Facilitator. Therefore, Staff will continue to work with the PA Team to expand on these high-level requirements through the PIM development or other UM 1930 processes. After pre-certification launches, Staff and the PA Team will continue to monitor the impact of these requirements as they align with the principles described in this report, and recommend modification as required.

Analysis—Transition between start-up and ongoing costs

Background on transition between start-up and ongoing costs

OAR 860-088-0160(1)-(2) sets forth the requirements for CSP administrative costs, distinguishing between start-up costs incurred during the development or modification of the CSP and ongoing costs. OAR 860-088-0160(1) requires start-up costs to be reviewed and approved by Commission order, and 860-088-0160(2) specifies that the appropriate share of ongoing costs for each project will be allocated in the Program Implementation Manual or otherwise determined by Commission. If the PA over-collects administrative fees, the excess funds are applied to future costs. If the PA under-collects funds required to perform its duties, the Commission may suspend further pre-certification of projects until the funding shortfall is resolved.

On March 5, 2019, the State of Oregon executed a contract for PA and LIF services with Energy Solutions.[25] The contract covers a three-year term and includes not-to-exceed costs for start-up expenses and annual ongoing expenses over the contract period. The ongoing not-to-exceed costs include a total annual dollar amount and a maximum amount that can be collected from CSP participants as an administrative fee. Further, the contract statement of work includes a requirement that the PA work with OPUC Staff to develop a shared framework for identifying and executing a transition from start-up to ongoing costs.

[24] This recommendation draws on experience from other states' solar programs. For example, the California Solar on Multifamily Affordable Housing (SOMAH) program has a requirement that 51% of incentives have to be passed on to the tenants while the 49% is allocated to the housing provider in order to support the housing provider's investment in these programs on behalf of tenants. See California CPUC decision D.17-12-022.
[25] Energy Solutions has subcontracted the LIF services to Community Energy Project.

The PA Team continues to refine its understanding of administrative tasks and associated costs through PIM finalization, completion of the CSP Software Platform, and additional launch tasks. However, it recognizes that Project Managers require certainty of ongoing administrative fees to prepare projects for pre-certification. At the time of this proposal, the PA Team finds that administrative tasks are understood well enough to classify start-up and ongoing expenses and establish a methodology to translate those budgets into an initial administrative fee structure. Therefore, Staff's proposal addresses the following issues simultaneously:

- The point at which the PA/LIF administrative costs transition from start-up to ongoing;
- The initial ongoing administrative fee structure that will recover these administrative costs.

Transition point

The legislature and CSP rules provide the Commission flexibility to establish a transition point for administrative costs that will balance project availability and ratepayer value. While the transition points discussed in this proposal will apply to both PA/LIF and any Commission approved utility administrative expenses, Staff's current proposal focuses on establishing a methodology to establish PA Team fees. Staff will engage in a separate process to identify utility ongoing costs once the CSP software platform and data exchange protocols are in place.

Staff has identified the following options for the transition point between start-up and ongoing costs:

- Task-based: The Commission designates specific administrative tasks as start-up activities. Only costs associated with these tasks are recoverable from ratepayers as start-up costs. Any other administrative costs are considered ongoing and borne by the program (project participants and/or Project Managers). Depending on the granularity of the task-based designations, start-up tasks may continue to occur after some ongoing tasks have begun. For example, the PA may continue finalizing the billing components of the software platform after pre-certification launches.
- Temporal: The Commission establishes a time-based start-up period during which all administrative expenses classify as start-up costs. Following that date, all administrative costs are borne by Project Managers and program participants.
- Capacity-Based: The Commission designates a capacity at which the program is self-supported. Once this level of program capacity is operational, subscribed, and billing participants, all administrative costs are borne by Project Managers and program participants.

To provide context to this discussion, Staff has identified three types of PA/LIF administrative activities, which are illustrated in Figure 4.

- Program development activities: Activities associated with building systems, developing policies, and establishing processes. These are one-off or limited duration activities and cannot be attributed to a specific project or participant.
- Program implementation activities: Activities that occur to implement the ongoing program's systems, policies, and processes. These activities can be one-off and driven by a specific project or participant, or can be regularly occurring over the life of the program and not attributable to a specific project or participant. For the purposes of establishing a transition point, Staff notes that there are certain interim activities that will begin once the systems and processes are in place, prior to any projects coming online and billing participants. These expenses could continue for up to 24 months before projects begin billing participants per the rules proposed in the PIM.

Figure 4 Summary of PA and LIF Activities

Program Development Activities

One-time or limited duration

- Program development activities:
  - PIM and other policy development
  - Project management
  - Reporting
  - Budgeting and invoicing
- Developing consumer resources (customer website, educational materials)
- Creating Project Manager resources (training, materials, pre-cert, and cert process development)
- Developing and testing the CSP software platform and other data transfer processes
- Low-income program design, network building, enrollment system development
- Establishing consumer support resources (contact center, dispute and consumer protection processes)
- Accounting and fund transfer process set-up

Program Implementation Activities

One-off: driven by a specific project or participant

- Project Manager Registration
- Pre-certification and Certification
- Participant eligibility verification
- Low-income participant placement
- Coordination and communications with Project Manager, OPUC and LIF regarding project

Interim

Regular: occur regardless of project or participant activity)

- Contact center (responding to consumer and Project Manager Inquiries)
- Queue and capacity tier management
- Maintaining consumer resources
- Maintaining Project Manager resources
- Low-income recruitment and verifying interested subscribers
- Project Manager and participant billing
- Program management activities:
  - PIM and other policy maintenance
  - Reporting
  - Budgeting and accounting
- Maintaining CSP software platform and other data transfer processes
- Customer service (resolving escalated complaints from participants)
- Ongoing Participant management and verification
- Ongoing Project Manager oversight and support
- Ongoing education, outreach, and marketing

The ongoing administrative costs borne by CSP participants are an important driver of project economics. Therefore, Staff analyzed how the three transition options balance the risks to project availability and ratepayers as shown in Table 2.

Table 2 Transition point trade-offs		
Options	Project availability	Ratepayer value
Task-based	• There's likely an interim period where there are no projects billing, but administrative costs being incurred • Risk of deterring early project development i.e., the first project to come online would bear all program administrative costs)	• Minimizes the administrative tasks that can be borne by ratepayers • Provides certainty for ratepayer costs • Risk of limiting the value ratepayers get in exchange for the start-up costs, in terms of project development
Temporal	Some risk of deterring or burdening early participants if adoption is slow, but allows for projects to utilize the full certification timeframe	• Risk of greater burden on all ratepayers if the program takes off quickly • Ratepayer risk limited by the timeframe • Timeframe provides some certainty for ratepayer costs
Capacity-based	Does not deter early project development	Highest risk of ratepayer burden if the program takes of slowly

Further, Staff notes that in a task-based transition, there will be a period of time between the conclusion of Program Development Activities and the time in which the PA will be able to collect fees from participants of operating projects. The current processes in the draft PIM allow this period to extend up to 24 months. These costs must be borne by the PA, Project Managers pre-certification application fees, or ratepayers.

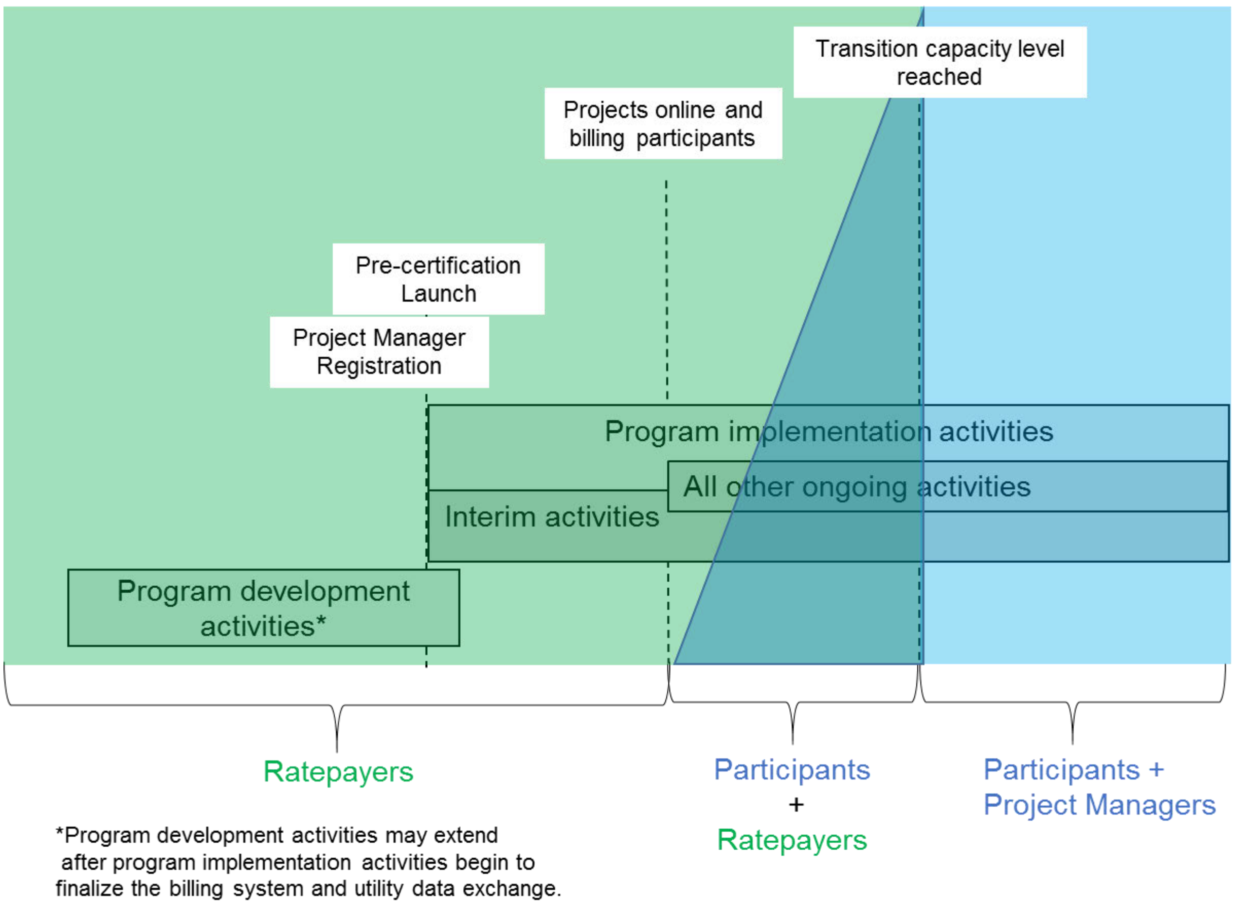
Recommendation: Staff finds that a task-based transition point is an important tool to minimize ratepayer impacts, and is most in line with the spirit of the law. However, Staff recognizes the risks of deterring early projects and the likelihood that there will be a period of time when there are no billing participants and, then, not enough participants to reasonably bear the ongoing costs. Therefore Staff proposes a hybrid approach to mitigate risks addressed in Table 2.

- Adopt a task-based transition point whereby Program Development Activities are considered start-up, and Program Implementation Activities are considered ongoing costs.
- To mitigate the risks to early adopters, establish a capacity-based point at which the size of the program can feasibly sustain the ongoing administrative fees. This level of capacity is herein referred to as "transition capacity level".
    - Set the administrative fees at the level that would recover all ongoing costs when the program reaches the transition capacity level.
    - Begin billing participants at the determined participation fee from the time the first project energizes, regardless of program size.
    - All other unfunded ongoing costs are considered start-up costs until the program reaches the transition capacity level (the difference between what's collected from participants and total ongoing costs). This means that the Commission will consider one-off interim tasks start-up costs until the program reaches the transition capacity level. Then, these costs can be recovered from Project Managers as pre-certification application fees or incorporated in participant fees.
- To mitigate risk to ratepayers if the transition capacity level is not quickly reached, establish a time-based off-ramp at 24 months following pre-certification

launch. If the transition capacity tier is not reached, the Commission will pause pre-certification and determine the appropriate next steps. Because this aligns with the end of the contract terms for PA services, this can be addressed in conjunction with analysis being performed for contract renewal.

Staff notes that a small number of tasks will occur without a clear distinction between start-up and ongoing, such as managing and reporting the program budget. Staff proposes that these tasks transition to ongoing when pre-certification opens, but receive the same capacity-based and temporal mitigation strategies described above.

Figure 5 Transition from start-up to ongoing



Ongoing administrative fee methodology

Staff proposes the following methodology to translate the transition proposal into a fee structure for ongoing administrative costs.

- Project Manager application fees cover one-off activities: Set the per-project pre-certification application fee ($/kW) to cover one-off ongoing activities driven by the pre-certification and certification process.
  - Consider one-off interim activities as start-up activities until the transition capacity level or 24 month off-ramp.
  - Regardless of timing, all projects are required to pay a $5/kW non-refundable deposit that will be deducted from the full amount of the application fee.
- Participant fees cover regular ongoing activities: Set the project participant administrative fee ($/kW/month) to cover the cost of regular ongoing activities at the transition capacity level.
  - The PA will begin collecting subscribers/owners' $/kW/month fee when each project begins billing subscribers/owners, regardless of the level of program capacity that is operating and billing.
  - Consider any unfunded administrative costs as start-up costs until the capacity of participants billed reaches the transition capacity level.

Following the transition from start-up to ongoing activities, the PA Team will report annually on actual administrative spending and adjust its forecast for the following year's administrative spending. The PA Team will subtract any excess funds collected in a year from the following year's budget, and adjust the following year's administrative fees accordingly (both participant fees, project application fees, and the project non-refundable deposit). Similar to the Energy Trust of Oregon process, the PA will present its annual budget for Commission review and recommendations.

Staff proposes that participant fees cannot exceed $2.46/kW/month per the contract for PA services, nor can the fee increase from the initial $/kW/month applicable at the time project pre-certification launches. This means that a participant can see its fee adjusted down, but will not see a fee higher than that assigned to the project at the time of pre-certification. Project certification fees ($/kW) can be adjusted up or down based on greater understanding of project financials and the actual costs associated with project certification as the program evolves over-time.

Staff proposes that the Commission adopt the annually adjusted PA fees by order. Once adopted, the PA Team will post the updated schedule on the CSP website and notify all registered Project Managers of the fee adjustment. Project Managers will be responsible for notifying participants of the change.

Fee assumptions for bill credit analysis

Based on the contract for PA Services, the PA Team forecasted the approximate administrative fees at different transition capacity levels (See Table 3). The PA Team adjusted the project certification fee to account for the fixed costs that are spread over the volume of applications at different capacity levels.[26] These values were used to model project economics in the bill credit analysis. To provide certainty for Project Managers and prospective participants, Staff proposes that the Commission adopt the initial administrative fees set forth in the bill credit

[26] The PA continues to refine its ongoing budget as program implementation details are finalized. The PA Team will provide detailed documentation and a final proposal for an initial fee schedule with the Staff report on October 4, 2019.

recommendation provided further in this report. However, Staff proposes that the PA Team reserve the right to adjust this scheduled prior to pre-certification launch if cost-efficiencies can be identified.

Table 3: Proposed Tentative Initial Administrative Fee Schedule				
Approx. MW subscribed and billing across utilities	% Capacity Tier (for context)	General Participant Admin Fee ($/kW/mo)	LI participant fee	Project Certification Fee ($/kW)
40.3	25%	$2.46	$0	$100*
80.5	50%	$1.50	$0	$75
120.8	75%	$1.00	$0	$50
161.0	100%	$0.85	$0	$40

*Adjusted to recover administrative fees not recovered under the $2.46/kw/month general participant administrative fee cap set forth in the contract for PA services.

Analysis—Bill credit rate

Background on bill credit rate

OAR 860-088-0170(a) required that, "unless otherwise determined by Commission order, the bill credit rate for a project will be based on the resource value of solar applicable to that project at the time of pre-certification and will apply for a term no less than the term of any power purchase agreement entered into pursuant to OAR860-088-0140(l)(a)." When adopting this rule, the Commission recognized that the resource value of solar was still under development in other proceedings and explained that:

> We agree with Staff that it is premature to adopt an interim rate. As discussed in this order, many steps remain in implementing this program. During the implementation process to follow, we direct Staff to work with the program administrator to monitor the progress of docket UM 1716 and to recommend appropriate action if it becomes apparent that delay in establishing a bill credit rate is delaying program launch.[27]

When establishing the size of the program, the Commission further noted that,

> Our intention in setting this initial limit is 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 farther expansion.[28]

Following the adoption of the CSP rules, parties continued to monitor the progress of the resource value of solar (RVOS) proceedings.[29] Through these efforts, the Commission adopted the Simple Retail Rate (based on the residential retail rate) as an interim bill credit rate for first 25 percent of each electric company's initial program capacity tier.[30,31] This decision was driven by to two concerns: 1) that RVOS rates were

[27] Order No. 18-177, p.
[28] Order No. 17-232, pp 7- 8.
[29] Docket Nos. UM 1716, UM 1910, UM 1911, and UM 1912.
[30] *See* Order No. 18-177, May, 23, 2018.
[31] Per OAR 860-088-0060, program capacity tier means the amount of total program capacity eligible for projects participating in an electric company's service territory, and is equal to 2.5 percent of the electric company's 2016 system peak.

unlikely to be finalized in time to facilitate a timely launch of the Community Solar program; and 2) the RVOS value would not result in subscription options being made available to customers.[32] Further the Commission noted that:

> Inherent tension exists in developing a program that encourages development and investment in Community Solar in a manner that creates fairness and equity for customers that do not have access to available net-metering solar opportunities or are low-income, with that of advancing fairness and equity by limiting cost-shifting to non-participants.

The Commission did not make a determination about the bill credit rate for the remaining 75 percent of the program capacity tier, but indicated that this interim rate will need to incorporate a transition to an RVOS based value. The Commission directed, "Staff, working with stakeholders should review transition options for consideration at a later date, and should keep us informed of important transition questions and issues as they emerge."[33]

Since the Commission's decision to implement an interim bill credit rate, Staff has monitored the development of RVOS and worked with the PA Team and industry experts, including the Energy Trust of Oregon, to expand its understanding of CSP project design and financials. A key learning from this work is that certainty over the bill credit rate is among the most important factors for a Project Manager to secure financing and take the risks associated with moving a project forward for pre-certification. Further, Staff and the PA Team learned that CSP project development carries additional costs that comparable solar projects with a single owner and/or single off-taker do not share. Finally, the RVOS dockets remain open and the utilities are still working to finalize values for application of the RVOS methodology. [34] This work is not specific to a CSP project.

Given these factors, Staff has developed a framework to evaluate:

- The specific value of the Simple Retail Rate (hereinto referred to as the "interim rate") for the first 25 percent of the program capacity tier (hereinto referred to as the "interim tier").
- The manner in which the CSP should transition to a rate based on RVOS after the interim tier.

Interim rate proposal

Staff finds that the interim rate has two pieces:

- Base rate: The value of the residential retail rate; and
- Adjustment: Whether that rate will remain fixed for the life of the agreement between the project and the utility to provide bill credits to participants, or float with the retail rate over that period of time.

<u>Base rate proposal</u>
Staff proposes the utilities calculate the base rate annually using the following methodology:

- The sum value of the rates for residential basic service, which includes transmission charges, distribution charges, the 1st 1,000 kWh energy charges, and system usage charges.

[32] Order No. 18-177, p. 1.
[33] *Ibid*, p. 4.
[34] *See* Order Nos. 19-021, 19-022, and 19-023.

- For simplicity and consistency, Staff does not recommend that the base rate include the various adjustments that the utility may apply outside of the charges listed above, such as Low Income Assistance, surcharges for pilot programs, or funds collected for the Public Purchase Charge, because these elements can vary over time, between utilities, and even between customers of the same utility i.e. franchise fees.
- The PA will assign the interim rate to projects using the base rate applicable at the time that the project applied for pre-certification. This rate will be applicable for a term no less than the term of any PPA between the project and the utility.

To provide certainty for prospective Project Managers, Staff proposes that the Commission adopt the base residential retail rates in Table 4 for any project pre-certified in 2019 and 2020. Starting on January 1, 2021, until the Commission determines that it will no longer accept pre-certification applications at the interim rate, utilities will file an update to the base rate by January 1st of every year. The updated rate will be adopted by the Commission and posted to UM 1930 and the CSP website. Staff recommends that the PIM provide a description of this process and a directions to locate the most recently updated base rate.

Table 4: Proposed Base Rates for 2019 and 2020						
Included charges	IPC		PAC		PGE	
	$/kWh	Tariff	$/kWh	Tariff	$/kWh	Tariff
Transmission charge ($/kWh)	-		$0.00473	Schedule 4	$0.00243	Schedule 7
Distribution charge ($/kWh)	-		$0.03598	Schedule 4	$0.04662	Schedule 7
Energy charge ($/kWh) - first 1,000 kWh	$0.0848	Schedule 1	$0.02927	Schedule 200	$0.06329	Schedule 7
			$0.02619	Schedule 201		
System usage charge	-		$0.00072	Schedule 4 (system usage charge for sch 200)	-	
			$0.00076	Schedule 4 (system usage charge for sch 201)		
Total Residential Retail Base Rate	**$0.0848**		**$0.0977**		**$0.11234**	

<u>Adjustment options</u>
Staff identified the following two options for the adjustment:

- Flat: Participants in the project receive the nominal value of the base rate at the time of pre-certification for the duration of the project.
- Floating: Participants receive the contemporary retail rate over the life of the PPA between the project and the utility, which will change when the residential retail rate changes.
    - Staff proposes that the floating rate is estimated as a fixed escalator, rather than an actual real time adjustment over the life of the project. This benefits the modeling in this report and upholds the project managers' and participants' need for certainty.
    - A look at recent trends in residential rates across the three utilities indicates that 2% annual increase is the appropriate proxy for residential rate increases. Staff suggests that the same proxy rate escalator be applied consistently across utilities for administrative and consumer consistency.

Table 5 Annual increase in residential retail rates for Investor Owned Utilities *as reported in 2017 OPUC State Book p. 5*		
Year	Residential Revenue per kWh (Oregon Average)	% annual increase
2013	10.75	2%
2014	11.40	6%
2015	11.55	1%
2016	11.43	-1%
2017	11.44	0%
5-year straight average annual rate increase		2%

The adjustment is one of many factors considered in Staff's bill credit analysis and proposal. These outcomes are summarized in Table 6.

Transition to RVOS

As stated previously, and noted by the Commission when adopting the CSP rules, the capacity of the program determines the administrative fees borne by participants. In turn, these fees directly inform project availability and low-income accessibility. The ability to reach the transition capacity tier, and quickly, then impacts overall ratepayer value. Therefore, Staff's bill credit rate analysis considers the feasibility of the two interim rate options if the program is at the current 25 percent interim capacity tier, as well as, 50, 75, or 100 of the program capacity tier. To measure the feasibility of transitioning to RVOS, the model also estimates program outcomes if participants are credited at the utilities' latest filed RVOS values.

Modeling outcomes

To measure the risks associated with different combinations of bill credit rate and program size, Staff worked with the PA Team to evaluate the balance between project feasibility and ratepayer impacts. To do this, the PA Team and Staff modeled the expected developer IRR and ratepayer impact of the bill credit over 20 years.

Staff recognizes that this is an entirely new solar model for Oregon and significant uncertainty exists around project design elements such as interconnection, financing, and subscriber acquisition costs. In addition, the PA and LIF are unique to Oregon and are expected to provide costs, benefits, and efficiencies not seen in other markets. Staff and the PA Team sought to model an average project based on industry experience and a review of five developers' pro forma (national and CBOs), but modeling outcomes are primarily intended to capture risk, considered imperfect, and subject to variation across actual CSP projects. Modeling assumptions are provided in Attachment B.

Table 6 Bill Credit Rate Modeling Outcomes						
Program Size	Bill Credit Rate	Project Manager 20y IRR	PGE Ratepayer Impact (% of Rev. Req.)	PAC Ratepayer Impact (% of Rev. Req.)	IPC Ratepayer Impact (% of Rev. Req.)	Gross 20y Ratepayer Impact ($M)
25% (40.3 MW)	RVOS	N/A	0.006%	0.007%	0.006%	$5.15
	Retail – fixed	4.11%	0.053%	0.043%	0.053%	$39.18
	Retail – floating	6.54%	0.075%	0.063%	0.081%	$56.16
50% (80.5 MW)	RVOS	(12.78%)	0.009%	0.009%	0.007%	$6.91
	Retail – fixed	5.40%	0.102%	0.083%	0.102%	$75.44
	Retail – floating	7.76%	0.147%	0.122%	0.158%	$109.66
75% (120.8 MW)	RVOS	(9.55%)	0.008%	0.009%	0.006%	$6.73
	Retail – fixed	6.03%	0.148%	0.119%	0.147%	$109.03
	Retail – floating	8.36%	0.215%	0.177%	0.231%	$160.10
100% (161.0 MW)	RVOS	(8.82%)	0.009%	0.009%	0.005%	$6.96
	Retail - fixed	6.22%	0.195%	0.156%	0.193%	$143.29
	Retail - floating	8.54%	0.284%	0.234%	0.305%	$211.33

Modeling suggests that a program size of 40 MW poses substantial risk to project availability at any of the rates considered. In addition, adopting the fixed retail rate or transitioning to RVOS without additional subsidy pose substantial risk to project availability at any of the program sizes considered.

At the floating retail rate, project availability appears to cross the 8 percent IRR threshold before the program reaches 120 MW and is close to feasibility when administrative fees are spread across 80 MW.

At the same time, the model suggests that the rate and program size combinations that minimize project availability risk are associated with $109 - $211 million of ratepayer subsidy compared to the cost purchase the CSP projects' generation at avoided cost rates over the same period of time. These costs are material and should be carefully weighed against the risks of project availability, considerations for equitable access, and value of providing certainty at higher capacity levels for community-driven projects.

> **Recommendation:** Staff recommends that the Commission adopt the floating retail rate as the interim rate, and establish the transition capacity level at 80 MW of subscribed capacity online and billing.[35] In addition, to ensure that there is enough Project Manager certainty and subscribed capacity to reach 80 MW of capacity online and billing within 24 months, Staff proposes that the Commission extend the interim rate to 75 percent of each utility's interim capacity tier. Without the headroom (i.e., if the interim rate were only applied to 50 percent of each utility's capacity tier) ratepayers will support the program administrative costs until each utility reaches its full capacity tier and all projects are 100 percent subscribed. Allowing up to 75 percent of each utility's capacity tier to receive the interim rate allows more flexibility for the 80 MW transition capacity level to be reached across utilities. In addition, the added certainty may help accelerate the speed at which Project

[35] As stated previously, 80 MW transition capacity level translates to $1.50/kW/month participant fee and a $75/kW application fee. Ratepayers will support unfunded ongoing costs until the program reaches the transition capacity tier or 24 months have passed since pre-certification launch.

Managers bring project forward for pre-certification and construction, further minimizing the administrative costs borne by ratepayers.

Staff's proposal is designed to walk a difficult line between standing up a stable program as quickly as possible, and prevent more ratepayer costs or risks than are necessary. This proposal creates a similar opportunity to that enjoyed by net metering participants to date, both in program size and bill credit value; it also increases certainty for all types of Project Manager without limiting the Commission's flexibility to monitor the market response before committing an incentive rate to the entire capacity tier. Staff finds that this flexibility is important given the remaining uncertainty around CSP project costs, the role of the PA team in reducing project costs, and the risk of extended ratepayer impacts if the program cannot reach stasis without ratepayer support.

In addition, Staff's proposal sets the transition capacity level such that the modeling outcomes are very close, but not quite above the IRR proxy for project availability. Spreading administrative costs over 80 MW represents a balance between project availability and ratepayer impact, given the need to provide additional headroom and the remaining uncertainties with project economics under this program model. As mentioned previously, Staff and the PA Team will continue to evaluate opportunities to drive efficiencies in ongoing costs as program design is finalized.

Finally, when RVOS values are finalized, Staff proposes to work with the PA Team to transition the interim rate such that it is based on RVOS. Specifically, the total interim rate value will remain the same, but it will be comprised of RVOS and a CSP incentive value. This will allow additional transparency into the incentive rate provided to CSP participants and simplify the process for the Commission to modify the CSP incentive value after 75 percent of a utility's capacity tier is allocated, based on actual market response and other data collected.

Other learnings and recommendations

Through its research and analysis, Staff and the PA Team identified new learnings, which facilitated additional recommendations to maximize the program outcomes without increasing ratepayer impact.

<u>Simplify Crediting Rules:</u> Staff and the PA Team attempted to model the month-to-month impact of the different CSP rates to ensure that there are no months where low-income participants' bills will be higher due to CSP participation. Staff and the PA Team found that the monthly kWh and volumetric caps are unnecessarily burdensome to low-income participants, while not affecting ratepayer impacts. These complex bill mechanics will be difficult for customers to understand, challenging to display clearly on bill, and increase the complexity and frequency of data calculations and exchanges between the PA, utilities, and Project Managers. To reduce technology and customer service costs, ease customer acquisition barriers, and protect low-income accessibility, Staff recommends that the Commission remove these requirements from the rules and provide the following bill mechanics:

- A participant's monthly total bill credit is calculated by multiplying the bill credit rate by the participant's share of total project generation in the month. This will be a dollar value referred to as the "total bill credit".
- If the value of the total bill credit exceeds the participant's total utility bill amount (in dollars), less any other on-bill repayment expenses, the excess bill credit amount (in dollars) is carried forward as a positive balance on the participant's account. This amount is referred to as the carry-over bill credit value.
- At the end of the annual billing cycle, any remaining carry-over bill credit value (in dollars) attributable to CSP participation must be donated to the low-income programs of the electric company serving the participant.

Small project carve out: In researching project economics and reviewing pro formas for different Project Manager types, Staff and the PA Team found that community driven projects (CBOs and government entities) still need to take advantage of economies of scale to pencil out. To preserve intent of this carve-out, Staff proposes that the Commission include both 360 kW and under projects, and projects with a non-profit or public entity as the Project Manager. Further, Staff proposes that the 25 percent carve-out apply for the entire amount of capacity allocated at the interim rate (i.e., 75 percent of each utility's capacity tier). This increases the maximum size of the carve-out from up to 10 MW of small and community-driven projects to up to 30 MW.

Table 7 Small and community-driven project carve out (MW)		
Utility	25 percent capacity tier (MW)	75 percent capacity tier (MW)
IPC	0.20	0.61
PAC	4.04	12.11
PGE	5.82	17.47
Total	10.06	30.19

Staff also proposes to use the definition of non-profit organization adopted by the Commission for the utilities' voluntary renewable energy grant programs:

> For the purposes of voluntary renewable programs, the term non-profit shall include any mutual benefit corporation, public benefit corporation, religious corporation, municipal corporation, or Indian Tribe as defined by Oregon Law. [36]

Staff proposes to work with the PA Team to monitor the usefulness of this carve-out and bring forward recommendations to amend or otherwise modify this carve-out based on actual project development data after pre-certification launches.

Support Project Manager acquisition costs: Staff finds that soft costs to acquire and maintain participants is among the areas where the most uncertainty and risk remain. Through start-up activities, ratepayers are investing in a Project Clearinghouse Website that allows prospective participants to review and compare CSP project options in a single, uniform venue. In an effort to drive down CSP project costs under the 80 MW transition capacity tier and maximize ratepayer value for this investment, Staff recommends that the utilities provide at least one communication per year that informs all customers of the CSP opportunity, and directs customer to the Project Clearinghouse and PA Team contact information to learn more about their options. The cost of these activities will be considered start-up costs until the capacity transition level is reached. At that point, Staff and the PA Team will work with utilities and stakeholders to determine if further support is required.

[36] *See* Commission Order No. 17-455, Docket No. UM 1020, November 8, 2017.

Staff proposes to work with the PA Team, utilities, and stakeholders to identify the specific consumer outreach actions that will best leverage greater program outcomes for a reasonable ratepayer costs.

Conclusion

On June 29, 2017, the Commission adopted administrative rules for the CSP. The Commission recognized that certain program decisions would be best resolved later in the implementation process to account for continued learnings and insight from the PA and LIF when selected. Staff, working with the PA, LIF, and the PA's partners continued to gather learnings on key policy decisions required for Project Managers to prepare projects for pre-certification through industry research and discussion with stakeholders. Given the PA Team's plan to launch pre-certification by the end of 2019, Staff finds it necessary for the Commission to resolve these outstanding questions at this time.

1. Bill credit
    a. Implementation of the Simple Retail Rate
    b. Transition after the interim capacity tier
2. Low-income participation requirements
    a. Minimum eligible low–income participants per-project (%)
    b. Requirements for low-income participation fees
    c. Definition of eligible low-income participant
3. Transition between start-up and ongoing costs
    a. Transition point
    b. Administrative fee methodology[37]

Staff identified the following decision making principles to guide its recommendations for key policy issues.

Overarching purpose – equitable opportunity: Staff proposes that the overarching objective of the CSP is to establish parity for consumers that have not been able to access solar customer generation opportunities and incentives.

Additional requirements: As a complement to the overarching purpose, Staffs finds that the CSP must balance the following minimum requirements.

- Low-income accessibility: Staff proposes a minimum expectation that low-income CSP participation makes low-income participants better off. This means the net impact of participation cannot result in an increase of low-income participant bills both month-over-month and over the life of a CSP subscription.
- Project availability: In addition, Staff identified minimum conditions for CSP project development to ensure that consumers will have access to opportunities to participate. These include:

[37] See Docket No. UM 1930, Staff's amended schedule, August 23, 2019.

  - Project Manager value: An 8 percent developer IRR on the average project represents a proxy for project development.
  - Project Manager certainty: Project Managers, at minimum, need to have a reasonable understanding of the administrative fees a project will incur as well as the bill credit rate that the PA will assign to the project (based on queue position and over time.)
  - Community-driven project certainty: Community-driven projects may need additional certainty about the availability of capacity beyond the initial tier and the bill credit rate assigned to that capacity.
- <u>Ratepayer value:</u> Ratepayers need the lowest cumulative ratepayer impact at which the other program requirements are achieved.

Staff's based its proposals on these decision-making principles. The Staff proposal based on these principles is summarized in Table 8. These recommendations are provided in the order provided in this report.

Table 8 Summary of Staff Proposal	
Policy Issue	**Staff's proposal**
The minimum low-income participation per project	10 percent per project
The minimum financial benefit for eligible low-income participation	20 percent subscription discount with preference for projects that can exceed 50 percent subscription discount
The manner in which bill credits must be linked to the electricity usage of individual low-income residential customers.	• A qualifying residential utility account holder that meets the income and other requirements set forth in the PIM. • A residential utility account holder with a utility allowance or other requirements of rent-assisted housing. • An affordable housing provider that directly pays for the residential electricity costs of tenants with household incomes that meet the income requirements set forth in the PIM and additional requirements for direct tenant benefits.
Transition to ongoing costs	• Limit start-up costs to specific program development activities. • Set ongoing administrative fees as if 80 MW are subscribed and billing. Collect participant fees from the day the project begins billing. Collect pre-certification application fees when the transition capacity tier is reached. • Backfill unfunded administrative costs with ratepayer funds until 80 MW is subscribed and billing. • Provide an off-ramp to pause pre-certification to determine the appropriate next steps if the program has not reached the 80 MW subscribed and billing 24 months following pre-certification launch.
Interim bill credit rate	Floating retail (residential retail + 2% annual escalator)
Interim rate capacity	Extend the interim rate to 75 percent of each utility's capacity tier
Simplify crediting rules	Remove monthly kWh and volumetric credit caps. Net participants usage and CSP generation annually and donate excess to utility low-income programs.
Small project carve out	Allow non-profit and government entities serving as Project Managers to qualify for the 25 percent of interim capacity small project carve out. Extend the 25 percent carve out to apply to 75 percent of each utility's capacity tier.
Mitigating acquisition costs	Require utilities to perform a minimum level of consumer outreach to inform consumers about the CSP program and direct consumers to the Project Clearinghouse and PA Team contact information.

Attachment A - Sensitivities for policy recommendation assumptions

Sensitivity: 50% minimum subscription discount for low-income w/ 30% bill credit adder for low-income participants (10% low-income participation)						
Tier Size	Bill Credit Rate	Project Manager 20y IRR	PGE Ratepayer Impact (% of Rev. Req.)	PAC Ratepayer Impact (% of Rev. Req.)	IPC Ratepayer Impact (% of Rev. Req.)	Gross 20y Ratepayer Impact ($M)
25%	Retail - fixed	4.37%	0.053%	0.043%	0.053%	$39.34
	Retail – 2%	6.66%	0.075%	0.063%	0.081%	$56.36
50%	Retail - fixed	5.63%	0.102%	0.083%	0.103%	$75.78
	Retail – 2%	7.87%	0.148%	0.122%	0.159%	$110.07
75%	Retail - fixed	6.26%	0.149%	0.120%	0.148%	$109.53
	Retail – 2%	8.47%	0.216%	0.178%	0.232%	$160.71
100%	Retail - fixed	6.44%	0.195%	0.157%	0.194%	$143.95
	Retail – 2%	8.65%	0.285%	0.235%	0.306%	$212.15

Sensitivity: 50% minimum subscription discount for low-income, no adder (10% low-income participation)						
Tier Size	Bill Credit Rate	Project Manager 20y IRR	PGE Ratepayer Impact (% of Rev. Req.)	PAC Ratepayer Impact (% of Rev. Req.)	IPC Ratepayer Impact (% of Rev. Req.)	Gross 20y Ratepayer Impact ($M)
25%	Retail - fixed	3.73%	0.053%	0.043%	0.053%	$39.18
	Retail – 2%	6.06%	0.075%	0.063%	0.081%	$56.16
50%	Retail - fixed	5.04%	0.102%	0.083%	0.102%	$75.44
	Retail – 2%	7.30%	0.147%	0.122%	0.158%	$109.66
75%	Retail - fixed	5.68%	0.148%	0.119%	0.147%	$109.03
	Retail – 2%	7.92%	0.215%	0.177%	0.231%	$160.10
100%	Retail - fixed	5.87%	0.195%	0.156%	0.193%	$143.29
	Retail – 2%	8.10%	0.284%	0.234%	0.305%	$211.33

Sensitivity: 50% minimum subscription discount for low-income for 5% capacity						
Tier Size	Bill Credit Rate	Project Manager 20y IRR	PGE Ratepayer Impact (% of Rev. Req.)	PAC Ratepayer Impact (% of Rev. Req.)	IPC Ratepayer Impact (% of Rev. Req.)	Gross 20y Ratepayer Impact ($M)
25%	Retail - fixed	4.01%	0.053%	0.043%	0.053%	$39.18
	Retail – 2%	6.32%	0.075%	0.063%	0.081%	$56.16
50%	Retail - fixed	5.37%	0.102%	0.083%	0.102%	$75.44
	Retail – 2%	7.62%	0.147%	0.122%	0.158%	$109.66
75%	Retail - fixed	6.04%	0.148%	0.119%	0.147%	$109.03
	Retail – 2%	8.27%	0.215%	0.177%	0.231%	$160.10
100%	Retail - fixed	6.24%	0.195%	0.156%	0.193%	$143.29
	Retail – 2%	8.46%	0.284%	0.234%	0.305%	$211.33

Sensitivity: 20% minimum subscription discount for low-income, but 5% low-income per project						
Tier Size	Bill Credit Rate	Project Manager 20y IRR	PGE Ratepayer Impact (% of Rev. Req.)	PAC Ratepayer Impact (% of Rev. Req.)	IPC Ratepayer Impact (% of Rev. Req.)	Gross 20y Ratepayer Impact ($M)
25%	Retail - fixed	4.20%	0.053%	0.043%	0.053%	$39.18
	Retail – 2%	6.56%	0.075%	0.063%	0.081%	$56.16
50%	Retail - fixed	5.55%	0.102%	0.083%	0.102%	$75.44
	Retail – 2%	7.85%	0.147%	0.122%	0.158%	$109.66
75%	Retail - fixed	6.21%	0.148%	0.119%	0.147%	$109.03
	Retail – 2%	8.48%	0.215%	0.177%	0.231%	$160.10
100%	Retail - fixed	6.41%	0.195%	0.156%	0.193%	$143.29
	Retail – 2%	8.67%	0.284%	0.234%	0.305%	$211.33

Sensitivity: Project Managers pay application fee without initial ratepayer support						
Tier Size	Bill Credit Rate	Project Manager 20y IRR	PGE Ratepayer Impact (% of Rev. Req.)	PAC Ratepayer Impact (% of Rev. Req.)	IPC Ratepayer Impact (% of Rev. Req.)	Gross 20y Ratepayer Impact ($M)
25%	Retail - fixed	2.87%	0.048%	0.039%	0.048%	$35.41
	Retail – 2%	5.30%	0.071%	0.058%	0.076%	$52.39
50%	Retail - fixed	4.40%	0.095%	0.076%	0.094%	$69.76
	Retail – 2%	6.77%	0.140%	0.115%	0.150%	$103.97
75%	Retail - fixed	5.34%	0.141%	0.112%	0.139%	$103.37
	Retail – 2%	7.68%	0.208%	0.170%	0.223%	$154.44
100%	Retail - fixed	5.66%	0.187%	0.149%	0.185%	$137.26
	Retail – 2%	7.99%	0.277%	0.226%	0.296%	$205.30

Attachment B – Modeling assumptions

The majority of inputs are informed by other solar models in Oregon, such as QFs, other states' CSP models that do not have a PA tasked with finding administrative efficiencies and driving down project costs. Within that context, key modeling assumptions include:

- Average project design
  - PGE service area project
  - 3 MWdc single axis tracking
  - 16% capacity factor
  - 95% subscribed after 2 years
  - Average LI participation level = 10%
  - LI participation fee = participation costs are 20% lower than residential participant bill credit rate
  - General participant fee set to secure financing = participation fee + admin fee is 5 percent below the bill credit rate. Staff and the PA team understand that financing a CSP project can be difficult without a baked-in financial benefit for participants. However, the amount of discount required to move forward with project development is driven by a range of project design, Project Manager, and participant factors. For example, national solar development companies assume a ten percent savings, however, community-driven projects assume a lower or no-savings subscription. Identifying an average project's participant savings is more difficult given the willingness of PGE and PAC customers to pay more to support renewables through the nation's top two performing voluntary green power products. Staff assumed that the average project provides a five percent general participant savings to capture this range between 0 and 10 percent.
- Average subscriber characteristics
  - All subscribers are residential
  - All subscribers are subscribed to 5 kW, which is 80% of usage based on a consumer that uses an average of 750 kWh per month
  - Home heating, but not home cooling usage patterns – usage declines slightly per year
  - Average residential rate increase of 2% per year – based on a straight average of the three utilities' rate increases over the past 5 years
- RVOS Values: The bill credit analysis assumes the RVOS values in Table 9, where are derived from each company's July 18, 2019 compliance filing.
- Ratepayer impacts were estimated using the same methodology described Staff's April 10, 2018 Staff report to UM 1930 p. 13 and the adjustments described in Staff's May 23, 2019 Staff report to UM 1930, with the following additions:
  - Includes estimated start-up an ongoing administrative costs prior to the 24 month off-ramp to reach the transition capacity level.
  - Adjusted revenue requirement assumptions to 2019($) at 2.8 percent based on Oregon Office of Economic Analysis Western Region CPI found at https://www.oregon.gov/das/OEA/Documents/forecast0919.pdf p. 42.

Table 9 Most Recently Filed RVOS Values			
RVOS Element	July 18, 2019 RVOS Values (Real Lev $2019/MWh)		
	PAC	PGE	IPC
Energy	20.18	26.78	28.77
Generation capacity	24.23	7.19	10.55
T&D capacity	2.89	7.91	6.03
Line losses	1.40	1.58	2.33
Integration	(0.63)	(0.83)	(0.57)
Administration*	N/A	N/A	(5.80)
Market Price Response	0.60	1.81	(0.02)
Hedging	1.01	1.34	1.44
Environmental compliance**	N/A	N/A	N/A
RPS compliance	(0.04)	3.76	N/A
Grid services TBD	-	-	-
Total 20 yr levelized RVOS ($/MWh)	49.64	49.54	42.73
RVOS ($/kWh)	**0.04964**	**0.04954**	**0.04853**

**Administrative costs are not included because CSP administrative costs are paid for through the recovery of CSP start-up and ongoing costs.*
***Environmental compliance values are information only per Commission order.*

Attachment C – Program Administration Team's Low-income Policy Analysis and Recommendations

Program Administration Team's Low-Income Policy Proposal

Introduction

The following paper outlines the Program Administrator's recommendations for low-income design principles, project requirements, participant requirements, policies and justifications. These recommendations were developed based on the program administrator's experience, stakeholder interviews, and review of national low-income best practices. Stakeholders, including utilities, project developers, and community-based organizations are encouraged to review and provide comments to each of the listed or proposed polices. The following topics are covered in this position paper:

1. Low-Income Program Design
2. Program Design Justification
3. Low-Income Subscription Eligibility
4. Low-Income Financial Incentives
5. Low-Income Capacity Per Project
6. Program Recommendations Summary

Low-Income Program Design

Program Design Goal:

Empower low-income ratepayers to take part in, and benefit from, the Community Solar Program.

Program Design Principles:

To reach the program goal that low-income ("LI") ratepayers take part in and benefit from the Oregon Community Solar Program ("CSP"), the program's design needs to include several key components, including accessibility by reducing barriers, participant protection, ensuring benefit, and encouraging diverse participation.

1. Accessibility: Community solar reduces the barriers around traditional rooftop installation and is an opportunity for solar to be accessible to low-income communities. However, there are still many opportunities for systemic lack of inclusivity to new audiences that must be addressed in the design phase. We aim to address these opportunities through:
    - **Reduced Financial Barriers to Participation:** Those with lower incomes do not have access to the same financial means as those with higher incomes. For example, upfront costs and penalties to leave the program would be significant barriers.

- **Financial Benefits**: Provide some fiscal resiliency to low income communities that are not controlled by external parties (such as housing providers and utilities). These financial benefits would allow LI subscribers to participate in the program to the fullest extent possible and in the same manner as other market participants.
- **Program Certainty and Program Uptake**: State agencies and nonprofits serving vulnerable populations are risk averse and are conservative when referring their participants to any programs. Therefore, community-based organizations ("CBOs") will be extremely reluctant to make referrals and participants are highly unlikely to engage with a program with uncertain risks or benefits. The CSP is a new program that is unvetted and unknown to trusted entities so eliminating as much program risk and uncertainty as possible will eliminate barriers to participation.

2. Participant Protection: The founding principle of the program's low-income program design is the idea of "do no harm". Vulnerable communities are frequently targeted with schemes that are deceptive and high risk. These activities result in increased energy bills, termination fees, misleading marketing, or complicated contracts. To avoid these types of negative impacts to communities, the program's participant protection activities include:

- Safe, standardized contracts that are in simple language that can be easily understood and translated into other written or spoken languages;
- Policies to ensure bills do not increase due to community solar subscriptions, especially in winter;
- Program administrator review of marketing tactics;
- LIF income verification to ensure a respectful, secure experience at signup.

3. Ensuring Benefit: Solar energy access has not been available to low-income audiences in Oregon. In order to engage and advertise to a new market, the program offering must meet a need. In the LI market, bill savings would meet a critical need, and would be highly marketable because of the following:

- The benefit provided to participants through this program will greatly impact the amount of outreach needed to engage LI participants.
- The benefit will directly impact how CBOs that serve LI communities will interact with the Program. The LIF knows this from 40 years of experience in serving LI communities. This knowledge was confirmed in the LI Stakeholder Meeting and the Diversity, Equity and Inclusion Stakeholder Meeting on April 29, 2019. In the DEI meeting CBOs (Self Enhancement Inc, NAACP, Urban League, Department of Human Services) informed the PA team that without any financial benefit, they would have little to no reason to refer a program to their clients as such a program would not meet any needs.
- Low-Income communities experience far more barriers than higher income Oregonians. From lack of internet access to displacement due to the statewide housing crisis, many LI

individuals navigate around these barriers and prioritize what helps with survival.[1] CBOs that serve frontline communities also prioritize what will best help their clients meet their needs.

- A recent NREL study found that "up-front cost can be a significant barrier for LMI customer participation. In a survey of approximately 500 potential LMI community solar customers, the Pacific Consulting Group (2017) found the top three considerations for participating in community solar were up front cost, percentage of bill covered, and initial contract duration."[2]

4. Encouraging Diverse Participation. This Program's LI mandate will allow for solar access to low-income communities and people of color for the first time. Programs are made equitable by removing barriers to participation and by creating programs that meet the relevant needs of those markets.
    a. For the last three years, the Community Solar Implementation Low-Income Subgroup (established by order 18-042) requested that the Program take multiple equity considerations into account while recruiting LI participants, including race, fixed income (such as those with disabilities and seniors), and rural participation. Requiring equity goals was also a key goal drafted by this Subgroup.[3]

Program Design Justification:

The key principles in the low-income program design are: accessibility by reducing barriers, participant protection, ensuring benefit, and encouraging diverse participation. If we follow the design principles detailed above, we will develop a program where low-income participants can participate and benefit without risk of harm.

Based on experience in other community solar markets such as Colorado, New York, and Maryland, the program design and principles assume that if the program does not provide substantial benefits and reduce accessibility barriers, enrollment of LI participants in the program will be difficult. This leaves the program with the risk of failing to meet the 10% low-income mandate. Through discussions with several CBO agencies (Self Enhancement Inc, NAACP, Urban League, Department of Human Services), programs are most successful with at least 20% bill savings for LI participants, with incentives to developers to help reach that target.

[1]Monica Anderson and Madhumitha Kumar,Pew Research Center, *Digital divide persists even as lower-income Americans make gains in tech adoption*, https://www.pewresearch.org/fact-tank/2019/05/07/digital-divide-persists-even-as-lower-income-americans-make-gains-in-tech-adoption/

[2] Jenny Heeter, Lori Bird, Eric O'Shaughnessy, and Sam Koebrich, *Design and Implementation of Community Solar Programs for Low and Moderate-Income Customers,* National Renewable Energy Laboratory, P. 21-22, https://www.nrel.gov/docs/fy19osti/71652.pdf?utm_source=NREL+Solar+Market+Research+and+Analysis&utm_campaign=76b463570b-EMAIL_CAMPAIGN_2019_03_28_04_02&utm_medium=email&utm_term=0_7e950366d3-76b463570b-289293163

[3] Goals and Equity Metrics of Low-Income Subgroup, Saved to Sharepoint.

NREL cites that a lack of bill savings was consistently listed as a disadvantage to successful approaches.[4] Most community solar programs that are being offered provide bill credits or savings for low income communities. NREL outlines that "Many utilities provide energy subsidies to low-income customers through ratepayer surcharges. These public utilities commission-mandated actions are known as utility-funded energy subsidies and are different from government assistance programs. Just as these 'discounts' are given to low-income citizens, they could also be used for community solar subscriptions. An informal survey by SEPA (2017a) found that nationally several utilities had bill reduction programs ranging from 10% to 50% of customers' bill."[5]

Low-Income Subscription Eligibility

Proposal:

"To qualify towards the Program's low-income requirement, a Subscription must be held by:

1. A residential utility customer with a household income of 80 percent or less than the of the Oregon State Median Family (or Household) Income, as defined by the U.S. Census American Community Survey, or;
2. An affordable housing provider that directly pays for the residential electricity costs of tenants with household incomes of 80 percent or less than the Oregon State Median Family Income, as defined by the U.S. Census American Community Survey. In addition to all other Subscriber eligibility requirements, affordable housing providers participating on behalf of low-income customers living in their building must:
   - Identify to the LIF the low-income customers, by name and housing units, on whose behalf they are participating (the "low-income beneficiaries");
   - Share at least 75 percent of any financial savings that result from the Subscription with the low-income beneficiaries;
   - Educate the low-income beneficiaries about community solar, the Project, how they benefit, and how to sign up with the Low-income Facilitator for another Project if they move.

Justification:

Low-Income is defined as 80% State Median Income (SMI).

A median household income refers to the income level earned by a given household where half of the households in the area earn more and half earn less. Using median instead of the average or mean household income gives a more accurate picture of an area's actual economic status. The SMI also has an income range based on the number of people in a household. In Oregon the median household SMI is $60,212 (2017)[6], however this is across all household sizes. The Federal Department of Health and Human Services adjusts the state SMI to account for different household

[4] NREL, 7
[5] NREL, 7
[6] US Census, American Community Survey (ACS) yearly survey.

sizes and sets levels below state household SMI as thresholds for a variety of federal and state programs. While in Oregon the median household SMI is roughly $60,000 (equaling roughly 2.5 people), the SMI for a family of 4 is estimated to be around $74,000.

At 80% of SMI, according to the table below, the qualifying income for a one-person family would be $30,793 a family of four is around $59, 217.

Table 1. Oregon State Median Income for FFY 2018[7]

Estimated state median income for a 4-person family: $74,022	80 Percent of Estimated State Median Income*					
	1-Person	2-Person	3-Person	4-Person	5-Person	6-Person
	Family	Family	Family	Family	Family	Family
	$30,793	$40,268	$49,743	$59,217	$68,692	$78,167

*In accordance with 45 CFR 96.85, 80 percent of each state's estimated median income for a 4-person family is multiplied by the following percentages to adjust for family size: 52 percent for one person, 68 percent for two persons, 84 percent for three persons, 100 percent for four persons, 116 percent for five persons, and 132 percent for six persons. For each additional family member above six persons, add 3 percent to the percentage for a six-person family (132%) and multiply the new percentage by 60 percent of the state's estimated median income for a 4-person family.

According to census data from the American Community Survey and accounting for a typical household size in Oregon, this would represent approximately 34% of Oregon households.[8]

In Oregon, State Median Income is used by LIHEAP (Low-Income Home Energy Assistance Program). While few agencies use SMI directly, hundreds of CBOs serve populations that fall within 80% SMI such those who use FPL (Federal Poverty Line). For example: SNAP (130% FPL), Section 8 (50% MFI), Head Start (100% FPL), and WIC (185% FPL) would all fall within the 80% SMI threshold. While LIHEAP uses 60% SMI, raising it to 80% SMI will be more realistic for the PGE territory.

The U.S. Dept of Housing and Urban Development sets their low-income threshold at 80% of the median income for a resident's county.[9]

Regulatory agencies outside of Oregon have accepted this income metric for qualifying participants in several programs including new and existing community solar programs. For example, Washington D.C.'s Solar for All program uses this threshold to target their low-income communities. Solar for All will provide the benefits of solar electricity to 100,000 low-income households (at or below 80% Area Median Income) and reduce their energy bills by 50% (based on the 2016

[7] https://liheapch.acf.hhs.gov/Tribes/Tables/povertytables/FY2018/orsmi_tribal.htm
[8] https://www.census.gov/cps/data/cpstablecreator.html
[9] US Dept of Housing and Urban Development, https://www.hud.gov/topics/rental_assistance/phprog

residential rate class average) by 2032.[10] In addition to D.C., California's solar programs such as Single Family Affordable Solar Homes (SASH) program also uses the same metric.[11]

Finally, during stakeholder meetings, the LIF reviewed a few standard methods currently used in Oregon to determine income qualification. After these meetings and conducting further research, the PA team recommended using 80% SMI for the following reasons:

1. SMI is set and updated annually by the U.S. Department of Health and Human Services to account for income changes.
2. SMI will provide easier, unified outreach across the state as the threshold will be the same regardless of county or utility service territory.
3. Using SMI helps give rural communities a slight advantage, as they are resource poor, but a higher threshold doesn't leave Multnomah County out. Median Family Income (MFI), another metric, tends to give wealthier counties advantages so for this reason, SMI was recommended by Community Action Partnership of Oregon (CAPO) and Oregon Housing and Community Services (OHCS).
4. Setting the percentage at 80% casts a slightly wider net of low-income Oregonians, increasing the likelihood of program success. An estimated 34% of Oregonian households fall below the 80% SMI.
5. It creates a diverse cross-section of lower-income Oregonians, to stabilize the subscription pool regarding turnover.
6. It's inclusive of the parameters often used by agencies that work with low-income communities.

To quantify this threshold, the LIF would verify whether the subscriber earns up to or below 80% of the State of Oregon's median income.

Exceptions

Master-metering exception

Regarding the exception proposed for affordable housing providers who directly pay the utility bills of their tenants under a master-metering situation, the intent is to provide a pathway for low-income customers living in this type of affordable housing to access the program. We do not have an exact count of the number of affordable housing properties that fall into this category, but we have been told in conversations with providers (including Pacific Crest Affordable Housing and Viridian Management), as well as with multifamily experts at Energy Trust and BEF, that the arrangement is uncommon. We have submitted a data request to OHCS to see if we can obtain this analysis to share with the Commission.

75% Pass Through Requirement for Master Meter Accounts

[10] Low-Income Solar Policy Guide, https://www.lowincomesolar.org/best-practices/district-of-columbia/

[11] Single-Family Affordable Solar Homes (SASH) 2.0 PROGRAM HANDBOOK, https://www.gosolarcalifornia.ca.gov/documents/SASH_Handbook.pdf

> "Affordable housing providers must share at least 75 percent of any financial savings that result from the Subscription with the low-income beneficiaries"
>
> The percentage level was selected to cover any administrative costs that a housing provider may incur by participating in the program and as an incentive for housing providers to subscribe to a project. It's seen that a percentage of benefits allocated to the housing provider is helpful to motivate enrollment and further investment in the property. The California SOMAH program has a requirement that 51% of incentives must be passed on to the tenants while the 49% is allocated to the landlord in order to provide motivation to invest in indirect tenant benefit such as other energy efficiency efforts.[12]

Engaging and educating tenants would be the responsibility of the housing provider, and they would receive information from the Project Manager and/or LIF. Basic educational information about community solar will already be available through the Program and the LIF. The exact form and mode of education can be up to the housing provider and tailored to fit the community. For example, an informational seminar might be the best fit for one property, whereas mailing/distributing informational materials and posting information on bulletin boards throughout the building might be more effective elsewhere. We do not perceive this to be a resource-intensive undertaking and would estimate the cost to Project Managers to be negligible, and within the scope of customer service and education expected for Subscribers.

Section 8 Housing Exception

The PA team recognizes that there are times in which the type of housing a LI Subscriber resides may deny them direct bill savings due to factors beyond our control such as utility allowance calculations. While our research says that this would not be a factor in the majority of LI housing, an LI Subscriber would not be disqualified from the program due to housing type or utility allowance calculations. Tenants that live in these type of housing situations, such as Section 8 housing, are not denied the possibility of participation because the bill credit may not be directly linked to a residential customer. If a tenant suddenly moves into Section 8 housing they do not have to lose their subscription. Due to subscription mobility, the tenant would be able to take a subscription with them, where they would receive the same bill savings/discount.

Agency participation

Many companies, nonprofits, and organizations serve low-income communities as tenants, customers, and clients. Aside from the master meter exception, an agency may not be able to count directly as a low-income participant. In the case of master meters, the majority of the benefit must go directly to the tenants. Low-income housing has been brought up consistently as an example, along with other businesses that may want qualifying-wage employees to become solar subscribers and CBOs serving low-income clients.

Agencies serving low-income populations may take part in two ways:

[12] California CPUC decision D.17-12-022, Pg 41-42,http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M201/K940/201940057.pdf

1. **As a Project Manager or Participant**: Agencies and businesses will be able to take part in up to 40% of a Community Solar Project and will be able to utilize their share however they like. The LIF will provide customized support in reaching low-income subscribers.
2. **As a Referring Entity**: Any agency serving low-income populations can refer their customers, employees, clients, tenants, etc. to be part of Community Solar Projects across the state.

Low-Income Financial Incentives

Proposal:

Low-income subscription costs must be discounted at 50%.

Justification for Financial Incentives

Evan Bixby with Pine Gate Renewables presented a pro forma to the PA team on June 7, 2019. He has several years of experience working in nonprofit community solar in New York for a nonprofit called Southern Tier Solar Works. He said that initial savings of 10% was not a compelling amount for the LI market, and until bill savings reached 20% (and they were able to work with their version of an equal pay program) the program was not successful. He reiterated the point in more detail in a one-on-one phone meeting asking about his experience with LI solar programs in NY.

In a monthly conference call with Vote Solar, the Maryland representative who works with the CS program expressed the same issue – that the program struggled until savings reached approximately 20% savings.

Achieving LI Savings Requirement

When proposing a minimum savings requirement for low-income subscriptions, a key design objective was to make progress towards reducing the energy burden on the low-income population in Oregon, in alignment with Executive Order 17-201[13] and the state's ten-year plan.

It is well documented that the average energy burden of low-income households and of communities of color far exceeds the average energy burden on median-income households.[14] The census data shows that on a national average, low-income households have an energy burden three times higher than non-low-income households. [15]In Oregon, the average affordability gap for energy burdened households earning < 200% Federal Poverty Line is $631 and is over $1,000 in many rural counties

[13] Governor Kate Brown Executive Orders, EO 17-20 "Accelerating efficiency in Oregon's built environment to reduce greenhouse gas emissions and address climate change" Nov 2017. https://www.oregon.gov/gov/Documents/executive_orders/eo_17-20.pdf
[14] Ariel Drehobl and Lauren Ross, American Council for an Energy Efficient Economy (ACEEE), "Lifting the High Energy Burden in America's Largest Cities: How Energy Efficiency Can Improve Low-Income and Underserved Communities" April 2016. http://aceee.org/research-report/u1602
[15]
3 New Tools for Advancing Energy Affordability in Low Income Communities,

(including Wallowa, Morrow and Jefferson counties, which overlap with the service territory of the Oregon CSP).[16]

The PA team received input from Oregon CBOs that low-income participants need to receive meaningful savings from participation in the Program.[17] In discussions about what constituted meaningful savings, CBOs suggested the following:

1. At least a 20 percent reduction in their electric bill
2. An average savings of at least $20 per month
3. Energy burden is at or below the average energy burden for non-LI customers
4. Annual savings that is on-par with the average payment from low-income energy assistance programs ($357.58)[18]

These recommendations from CBOs align with the findings from national studies performed by NREL, LBNL, GTM Research, Vote Solar and others. It has been well documented in the literature that LMI households require tangible financial savings and typically cannot afford upfront investments. In a recent report, GTM Research found that "Low- and moderate-income subscribers put top priority on tangible economic savings from community solar, often need higher relative discounts on their energy bill—sometimes at least 20%-50%—to see the same dollar savings." They found the same to be true for affordable housing operators. "Operators are often looking for energy bill discounts of 20% or more," according to GTM Research interviews.[19]

Their research further found that "even 10% to 20% percent savings is not sufficient because of the higher energy burden of low-income households." The report goes on to explain: "conversations with market participants validate the fact that higher energy burdens mean that community solar subscriptions need to offer anywhere between at least 20% and upwards of 50%-year 1 bill savings in order to secure commitments from LMI subscribers. The lower end of that range is more viable for master-metered affordable housing property owners, where bill savings are not always directly passed through to the tenants. One notable exception to that range is in Colorado, where much of the initial community solar capacity installed that serves LMI subscribers offers greater than 50% bill savings."

Other states have incorporated this understanding into their community solar low-income program designs. The Colorado Energy Office targeted a 30%–50% reduction in LMI bills through its community solar pilot programs, and a 50% bill savings target is required by low-income solar

[16] The data referenced is for households at or below 200% federal poverty level (FPL), which does not align with the program's definition of low-income (less than 80% SMI).
[17] Community Energy Project held stakeholder meetings with CBOs on 4/25/2019,2/26/2019, and 4/29/2019. The Oregon Low- to Moderate-Income Solar Working Group also discussed requirements for low-income participation in community solar at its 7/31/2018 meeting and throughout all the other meetings more broadly.
[18] State Yearly Program Snapshot Report for LIHEAP and OEAP in 2016 for all Oregon counties. $357.58 was the average annual payment amount for the 81,872 households served.
[19] Wood Mackenzie and GTM Research, "The Vision for U.S. Community Solar: A Roadmap to 2030" July 2018. https://votesolar.org/policy/policy-guides/shared-renewables-policy/csvisionstudy/#reportdownload

programs in California and Washington D.C. These targets were developed with the purpose of lowering LMI energy burden.

In considering how to structure the minimum savings requirement for low-income subscriptions, we considered a variety of savings targets, relative to various income levels, which are summarized in Table 1.

Table 1. Design options for achieving savings for low-income CSP participants

Assumptions for 4-Person Household	40% SMI	60% SMI	80% SMI
Annual electricity expenses before CSP[20]	$ 1,281	$ 1,281	$ 1,281
Annual income	$ 29,609	$ 44,413	$ 59,217
Electricity burden before CSP	4.3%	2.9%	2.2%
Annual electricity use (kWh)	11,645	11,645	11,645
Full retail rate	$0.110	$0.110	$0.110
Annual Savings Targets	**40% SMI**	**60% SMI**	**80% SMI**
20% bill reduction	$ 256.20	$ 256.20	$ 256.20
50% bill reduction	$ 640.50	$ 640.50	$ 640.50
Equivalent to avg LIHEAP/OEAP	$ 357.00	$ 357.00	$ 357.00
$20 per month	$ 240.00	$ 240.00	$ 240.00
Reduce electricity burden to 2%	$ 688.83	$ 392.74	$ 96.65

There are two factors that determine the total savings a subscriber will receive as a result of a CSP subscription: the <u>price of the subscription cost relative to the bill credit</u> and the <u>size of the subscription</u>.

Though the overarching design goal may be to achieve a certain level of savings for the customer, explicitly requiring that subscriptions save customers a specific percentage (e.g. 25% bill reduction) or a minimum amount of money (e.g. $250 a year) could be challenging for Project Managers to implement and guarantee year-over-year, and for the PA to verify. It would require significant customization of each subscription offer to each customer, which increases sales and transaction costs. It also obligates Project Manager to provide performance guarantees, which is an additional cost and risk for them to bear.

A requirement to discount the subscription cost guarantees a certain level of discount but does not directly translate into a specific level of bill savings. **The actual bill savings a customer will experience will depend on not only the discount, but the difference between the bill credit rate and the customer's retail rate, as well as the size of the subscription.**

For example, a subscription that is discounted by 50%, and sized at 50% of the customer's load, would deliver a bill savings of approximately 25% (or a little less, factoring in non-volumetric

[20] Average annual electricity bill for an Oregon LMI household, defined as HH income ≤120% AMI. American Community Survey 5-year Estimate, Census 2015 self-reported figures. https://lmisolaroregon.files.wordpress.com/2017/03/fact-sheet-lmi-housing-types-and-meaningful-savings.pdf

charges). If that same subscription was sized to offset 80% of the customers load, it would deliver bill savings of approximately 40%. If the bill credit rate is lower than retail rate, the relative benefit to the customer's bill decreases.

We believe that requiring LI subscriptions to be discounted in a way that results in a savings regardless of the bill credit rate, is the best way to ensure that low-income participants will receive meaningful and tangible financial savings. It also gives Project Managers the flexibility to size subscriptions as they desire and plan their product offerings without specific knowledge of individual participants' energy bills. The relationship between subscription discount, subscription size and bill savings for the interim bill credit rate is shown in Table 2.

From conversations with potential Project Managers, the PA team believes that Project Managers will tend to size their low-income subscriptions to be a large as possible, but with margin of **10-20% less than their estimated annual usage,** to avoid having to adjust subscriptions because of a reduction in customer load. This helps them control their customer acquisition management costs. Other potential Project Managers have said that they plan to offer standard sized subscriptions (e.g. 5 kW portions). This helps simplify their sales process and reduces customer acquisitions costs. Thus, we are anticipating that, if given the flexibility to size LI subscriptions as they choose, Project Managers will tend to size subscriptions in the 50-90% offset range.

Table 2. Approximate volumetric bill savings resulting from different levels of subscription discount and subscription sizes, when the bill credit = retail rate

Subscription Discount \ *Subscription Size (as a % of bill offset)*	0%	10%	20%	30%	40%	50%	60%	70%	80%	90%	100%
0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
10%	0%	1%	2%	3%	4%	5%	6%	7%	8%	9%	10%
20%	0%	2%	4%	6%	8%	10%	12%	14%	16%	18%	20%
30%	0%	3%	6%	9%	12%	15%	18%	21%	24%	27%	30%
40%	0%	4%	8%	12%	16%	20%	24%	28%	32%	36%	40%
50%	0%	5%	10%	15%	20%	25%	30%	35%	40%	45%	50%
60%	0%	6%	12%	18%	24%	30%	36%	42%	48%	54%	60%
70%	0%	7%	14%	21%	28%	35%	42%	49%	56%	63%	70%
80%	0%	8%	16%	24%	32%	40%	48%	56%	64%	72%	80%
90%	0%	9%	18%	27%	36%	45%	54%	63%	72%	81%	90%
100%	0%	10%	20%	30%	40%	50%	60%	70%	80%	90%	100%

Other Low-Income Financial Incentive Proposals

Although the policy listed above is the Program's ideal proposal that allows for the most low-income participation and subscriber benefits, the following are other policy proposals that are being considered. Stakeholders should consider providing public comment on any or all of the proposed or considered low-income incentive policies:

1. Low-income subscription costs must be discounted at 20% and the developer incurs a 30% adder creating a net 50% discount for low-income subscribers.
2. Low-income subscription costs must be discounted at 20% and ratepayers incur a 30% adder creating a net 50% discount for low-income subscribers.
3. Low-income subscribers receive 20% bill savings.
4. There is no subscription cost discount requirement enforced for developers but providing a 50% discount is highly incentivized. These incentives could be related to specific project designation and reducing other program barriers.
5. Low-income subscription costs must be discounted at 50% but the low-income dedicated capacity per project is reduced from 10% to 5%.

LI Subscriber Capacity per Project

Proposal:

10% of each Project should be comprised of LI subscribers.

Justification:

The Colorado case study exemplifies how setting up a project threshold becomes a ceiling or cap on low-income participation. The Low-Income Solar Policy Guide sites this experience in Colorado:

"The five percent low-income minimum participation level for community solar projects in Xcel Energy's service territory in Colorado, though successful in meeting the target, functioned as a ceiling to low-income participation. The bid process to secure placement in the program resulted in a highly competitive program, and thus, very thin margins for developers and financiers. The low-income carve-out further eroded these margins, making it extremely unattractive to exceed the mandatory five percent amount; in practice, due to the way the program was structured, no developers exceed this requirement and effectively "wrote off" low-income participants as another program cost."[21]

Relationship between Subscriber Requirement and Bill Credit

Irrespective of rates, not requiring 10% LI capacity for each project would be a significant program risk eroding the legislative requirement of 10% for the program as a whole. Allowing for a lower threshold (e.g. 5%) with no guarantee for higher LI projects is a program risk. As previously mentioned from the Low-Income Solar Guide, existing community solar programs have not shown

[20] Low-Income Solar Policy Guide, https://www.lowincomesolar.org/best-practices/community-solar-colorado/

LI capacity to exceed minimum thresholds established in program rules because there is simply not a market incentive for developers to over-subscribe this type of capacity.

LI Focused Solar Projects

The PA team is not aware of any significant 100% LI projects in the queue that would "buoy" other market rate projects with less than 10% LI capacity. We are aware that reaching 10% LI capacity for each project will be challenging, however, lowering the threshold will only make it more challenging to hit the 10% program-wide mandate as the program matures. We have not seen or heard about any concrete solar projects that would fill the additional 5% requirement if project developers only do the expected minimum required of them.

Summary of PA Recommendations

Based on stakeholder feedback, Program Administrator team experience, and a comprehensive review of state and national program standards, the following are the PA Team's Low-Income Policy recommendations along with their justifications.

Program Design Principles

1. Accessibility: Community solar reduces the barriers around traditional rooftop installation and is an opportunity for solar to be accessible to low-income communities. However, there are still many opportunities for systemic lack of inclusivity to new audiences that must be addressed in the design phase.
2. Participant Protection: The founding principle of the program's low-income program design is the idea of "do no harm". Vulnerable communities are frequently targeted with schemes that are deceptive and high risk. These activities result in increased energy bills, termination fees, misleading marketing, or complicated contracts.
3. Ensuring Benefit: Solar energy access has not been available to low-income audiences in Oregon. In order to engage and advertise to a new market, the program offering must meet a need. In the LI market, bill savings would meet a critical need, and would be highly marketable.
4. Encouraging Diverse Participation. This Program's LI mandate will allow for solar access to low-income communities and people of color for the first time. Programs are made equitable by removing barriers to participation and by creating programs that meet the relevant needs of those markets.

Low-Income Subscription Eligibility

Proposal:

"To qualify towards the Program's low-income requirement, a Subscription must be held by:

3. A residential utility customer with a household income of 80 percent or less than the of the Oregon State Median Family (or Household) Income, as defined by the U.S. Census American Community Survey, or;
4. An affordable housing provider that directly pays for the residential electricity costs of tenants with household incomes of 80 percent or less than the Oregon State Median Family Income, as defined by the U.S. Census American Community Survey. In addition to all other Subscriber eligibility requirements, affordable housing providers participating on behalf of low-income customers living in their building must:
   - Identify to the LIF the low-income customers, by name and housing units, on whose behalf they are participating (the "low-income beneficiaries");
   - Share at least 75 percent of any financial savings that result from the Subscription with the low-income beneficiaries;

- Educate the low-income beneficiaries about community solar, the Project, how they benefit, and how to sign up with the Low-income Facilitator for another Project if they move.

Low-Income Financial Incentives

Proposal:

Low-income subscription costs must be discounted at 50%.

Justification:

Though the overarching design goal may be to achieve a certain level of savings for the customer, explicitly requiring that subscriptions save customers a specific percentage (e.g. 25% bill reduction) or a minimum amount of money (e.g. $250 a year) could be challenging for Project Managers to implement and guarantee year-over-year, and for the PA to verify. It would require significant customization of each subscription offer to each customer, which increases sales and transaction costs. It also obligates Project Manager to provide performance guarantees, which is an additional cost and risk for them to bear.

A requirement to discount the subscription cost guarantees a certain level of discount but does not directly translate into a specific level of bill savings. The actual bill savings a customer will experience will depend on not only the discount, but the difference between the bill credit rate and the customer's retail rate, as well as the size of the subscription.

Low-Income Capacity Per Project

Proposal:

10% of each Project should be comprised of LI subscribers.

Relationship between Subscriber Requirement and Bill Credit

Irrespective of rates, not requiring 10% LI capacity for each project would be a significant program risk eroding the legislative requirement of 10% for the program as a whole. Allowing for a lower threshold (e.g. 5%) with no guarantee for higher LI projects is a program risk. As previously mentioned from the Low-Income Solar Guide, existing community solar programs have not shown LI capacity to exceed minimum thresholds established in program rules because there is simply not a market incentive for developers to over-subscribe this type of capacity.