ITEM NO. 2

PUBLIC UTILITY COMMISSION OF OREGON
STAFF REPORT
PUBLIC MEETING DATE: February 14, 2019

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

DATE: February 8, 2018

TO: Public Utility Commission

FROM: Caroline Moore JPB for CM

THROUGH: Jason Eisdorfer and JP Batmale BC for JE JPB

SUBJECT: OREGON PUBLIC UTILITY COMMISSION STAFF:
(Docket No. UM 1930) Community Solar Implementation Update.

STAFF RECOMMENDATION:

Informational filing - no recommendation.

DISCUSSION:

Issue

This report provides an update on several key Community Solar Program (CSP) implementation milestones:

- The competitive selection of the CSP Program Administrator (PA);
- The establishment of the process by which utilities will recover program start-up costs;
- The Commission decision concluding Phase II of the Resource Value of Solar docket; and
- The activity of CSP implementation subgroups, including Staff's response to the Project Details' Subgroup request to clarify whether CSP projects are required to interconnect with utilities as Qualifying Facilities (QFs).

Applicable Law

Section 22 of Senate Bill (SB) 1547, effective March 8, 2016 and codified in Oregon Revised Statute (ORS) 757.386, directs the Public Utility Commission of Oregon

(Commission) to establish a community solar program (hereinafter referred to as "Program", or "CSP").

CSP Program Administrator
Division 88 of Chapter 860 of the Administrative Rules specifies that the Commission will select a CSP Program Administrator (PA) and Low Income Facilitator (LIF) through a competitive bidding process.[1]

Competitive Procurement
Oregon Administrative Rules (OAR) Chapter 125, Division 246 delegate procurement authority to the Department of Administrative Services (DAS) for procurements exceeding $150,000. ORS 279B.060 and OAR 125-247-0260 set forth the methods for competitive sealed proposals. A combination of these methods is deployed in the process to procure CSP Program Administrator services.

CSP Cost Recovery
ORS 757.386(7) specifies different treatment for the start-up and ongoing costs of the CSP.

1. Start-up costs: Utilities may recover prudently-incurred program start-up costs as well as costs of energy purchased from CSP projects (Projects) from all ratepayers.
2. Ongoing costs: Owners and subscribers (i.e., program participants) bear the cost to construct and operate Projects, plus ongoing program administration costs.

OAR 860-088-0160(1) clarifies that start-up PA and LIF costs are recoverable in rates of all ratepayers. Further, the rules specify that utilities' prudently-incurred start-up costs recoverable from ratepayers include, but are not limited to, costs associated with customer account information transfer and on-bill crediting and payment, but exclude any costs associated with the electric company developing a project.[2]

OAR 860-088-0160(2) clarifies that ongoing PA and LIF costs are collected from CSP participants.[3]

CSP Project Integration
ORS 757.386(2) directs the Commission to:

(A) Adopt rules prescribing what qualifies a community solar project to participate in the program;

[1] OAR 860-088-0020(1) and OAR 860-088-0030(1).
[2] OAR 860-088-0160(1)(b).
[3] The program rules do not specify recovery for utilities' ongoing costs.

(B) Certify qualified community solar projects for participation in the program;
(C) Prescribe the form and manner by which project managers may apply for certification under the program; and
(D) Require, by rule or order, electric companies to enter into a 20-year power purchase agreement with a certified community solar project.

ORS 860-088-0140 clarifies that, upon certification, a CSP 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.

OAR 860-088-0040(1)(d) requires CSP projects to follow the state's Division 82 Small Generator Interconnection (SGI) Rules and in adopting these rules. When adopting these rules, the Commission further indicated that "the success of a prospective project depends on completing the interconnection process and that this step could cause costly delay for project managers. We ask Staff and stakeholders to consider during development of the program implementation manual the potential role of the program administrator ensuring nondiscriminatory access and evaluating whether the interconnection process is fair and functional for projects seeking to enter the community solar program."

Analysis

Background
At the November 20, 2018 Public Meeting, Staff provided an information only status report on UM 1930 Community Solar Program Implementation. Staff committed to update the Commission on the status of CSP implemtnation in January 2019, including the status of PA selection and cost recovery efforts. Staff is providing this update in February 2019 due to the timing of important CSP implementation milestones.

PA Contract Update
A contract for PA services is in the process of being finalized and will be circulated by DAS for signatures. Staff anticipates that the contract will be executed within 30 days of this status report. Staff plans to notify the UM 1930 service list when the contract is

executed and update the Commission at a Public Meeting with available details about the timing and structure of CSP implementation efforts to be performed with the PA. If the scope of contract implementation does not change, Staff should be able to introduce the PA and initiate the Program Implementation Manual (PIM) development process by the second quarter of 2019.

Per state rules, DAS will remain the single point of contact throughout the remainder of the contracting phase.

Cost Recovery Update
On December 18, 2018, the Commission issued Order Nos. 18-477 and 18-478, approving Portland General Electric (PGE) and PacifiCorp's (PAC) respective applications for deferred accounting of PA/LIF and utility non-capital start-up costs.[4] PAC and PGE will file tariffs to collect start-up costs from ratepayers when the contract for PA services is executed and the PA/LIF's costs and utility requirements are known. Staff will work with the utilities on tariff preparation.

Staff will continue to update the Commission on the status of cost recovery efforts, including a status update no later than April 2019.

RVOS Phase II Completion
On January 22, 2019, the Commission issued Order Nos. 19-021, 19-022, and 19-023 completing Phase II of the RVOS proceeding, adopting RVOS calculation methodologies for PAC, IPC, and PGE respectively, and directing the three utilities to file revised RVOS values by March 18, 2019 along with additional revised values for specific elements by July 18, 2019. The order does not address application or implementation of RVOS for the CSP bill credit rate.

Finalizing the initial RVOS methodologies and values within the next six months has ramifications for future CSP implementation and adoption. Per previous direction from the Commission, Staff will work with the PA and stakeholders to develop transition plans from the interim alternative bill credit rate to a bill credit rate based on RVOS through development of the PIM and/or other implementation work streams identified with the PA.[5] Staff will update the Commission on the status of RVOS transition planning efforts once underway.

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[4] The Commission approved Idaho Power Company's (IPC) application for deferral of start-up expenses for the community solar program with Order No. 16-410 issued on October 25, 2016. IPC has proposed to defer all start-up costs and begin recovery in rates after the start-up period is ended. This does not require a tariff to be filed at this time.

[5] Commission Order No. 18-177 adopts the interim alternate bill credit rate for the first 25 percent of the capacity tier, identifies the first 25 percent of the capacity tier as a "check-in" point for transition to an RVOS-based bill credit rate, and directs Staff to work with stakeholders to review transition options for

Update from the Subgroups
Throughout 2018, Staff and stakeholders worked collaboratively to continue moving implementation forward by discussing and documenting major issues for the incoming PA/LIF. Staff provided an update from the subgroups in its July 31, 2018 status report. This status report provides an update on the subgroup activities following the July report.

The Project Details and Low Income subgroups continued to meet following the July 2018 update.[6,7] The Project Details subgroup activities are summarized in the table below and a full update is provided in Attachment A of this report.[8] As of the time of this memo, the Low Income subgroup is still finalizing reports related to equity principles and metrics, considerations for housing providers, potential incentive needs, and additional resources developed for the PA/LIF. Staff recognizes how critical the low-income opportunity is to the CSP's success and encourages the subgroup to take the time needed to thoroughly document its efforts. Staff will provide the subgroup report as a consent agenda item on the February 26, 2019 public meeting.

Staff appreciates the hard work and dedication demonstrated by the subgroups. Participants continue to invest significant time to identifying, researching, and discussing difficult implementation issues—including systemic issues that extend beyond their impacts on the CSP. Staff is particularly grateful to the subgroup leaders, who continuously dedicated additional time to facilitating, documenting and, organizing the content of these discussions.

At present, the subgroups are focused on finalizing resources that will be provided to the PA/LIF to support development of the PIM manual and other implementation activities.

Additional subgroup meetings are not scheduled at this time.

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consideration at a later date and keep the Commission informed of important transition questions and issues as they emerge.
[6] The Project Details subgroup focuses on CSP project requirements and certification processes. *See* Attachment A for additional details.
[7] The Low Income subgroup focuses on issues unique to supporting low-income participation and meeting low-income requirements.
[8] Staff notes that the subgroup report provided in Attachment A represents the statements and perspectives of subgroup participants and subgroup leaders, but does not reflect Staff's statements, positions, or perspectives on the content or characterization of subgroup discussions.

Subgroup	Key Developments Since July 2018 Update
Project Details	• Raised concerns about interconnection costs and asked Staff to clarify whether CSP projects will be required to interconnect with the utility as QF's under PURPA. **Additional discussion of this important question is provided in the next section of this status report.** • Reached subgroup consensus on several certification and registration requirements for Project Managers; identified opportunities to balance accessibility and diligence in these processes; identified many additional questions and considerations for Project Manager Registration and project certification. • Identified important questions about when and how Project Managers can engage utility customers; discussed the appropriate level of transparency available to consumers comparing available CSP projects on a central, public "clearinghouse." • Raised questions, concerns, and considerations regarding project sizing and siting rules and protections. • Raised the concept of a "soft launch" to speed program launch; identified important questions about CSP project queue management and transitioning beyond the initial capacity tier. • Identified opportunities to mitigate utilities' competitive advantages over third-party Project Managers.
Low Income	Formed subcommittees to focus on the following: • Developing Low Income Principles and equity metrics for key elements of the program implementation; • Outlining potential scenarios under which housing providers could hold subscriptions on behalf of low-income customers; and • Identifying potential low-income incentive structures, including a review of other state program models.

Staff response to subgroup questions regarding QF designation

After considerable discussion, the Project Details Subgroup asked Staff to clarify whether CSP projects must be QFs to receive certification. Staff understands that the underlying motivation for this question is concern from prospective Project Managers that have received or anticipate receiving interconnection studies that indicate prohibitively high cost network upgrades will be a condition of interconnection for their projects. Oregon QFs are required to interconnect with the utility system as a Network Resource (as compared to an Energy Resource) where payment of any resulting network upgrade costs are studied to include firm deliverability to load under severe circumstances and are the responsibility of the QF. Project Managers are seeking to find an alternative way to interconnect with public utilities without the need to bear as much or any cost for network upgrades. Staff understands that Project Managers also seek to interconnect as non-QFs because of concerns related to QF interconnection processes and requirements. These other concerns include management of the interconnection queue, interconnection study timing and methodologies, and the lack of transparent information about areas of the utilities' systems where projects can interconnect without significant network upgrade costs. Stakeholders explain that information regarding the utilities' systems is not readily available and that guessing where interconnection is most viable is difficult.

Staff analyzed both the legal and practical considerations of requiring CSP projects to interconnect with the utility as a QF. In consultation with the Department of Justice, Staff concluded that requiring that the Projects be QFs would allow the Commission to determine the price and terms for all sales of unsubscribed generation from all CSP Projects. (See Attachment B for detailed explanation). Without a requirement to interconnect as a QF, the Commission may not have the authority to set terms for the sale of unsubscribed power to the utility. Further, Staff finds value in requiring network resource status, regardless of QF status, to ensure firm deliverability of CSP project output to load without placing the cost of deliverability on non-participants. Consequently, Staff plans to propose QF status as a requirement for project certification in the PIM.

Staff provided this clarification to the Project Details subgroup on February 5, 2019. Staff invited subgroup members to provide informal comment on this analysis within the subgroup or share more formal comments within the UM 1930 docket.

While CSP projects have the clarity to proceed with the utility interconnection process, the underlying concerns about potentially high or unsubstantiated network upgrade costs remain. It is clear to Staff that it is important to begin working with utilities and stakeholders to identify near-term opportunities to mitigate interconnection barriers for CSP projects, while coordinating with broader efforts to identify solutions to the underlying issues associated with small generator interconnection processes and costs e.g., PURPA Implementation Review, Integrated Resource Planning, and Distribution System Planning.[9] Staff plans to begin working with utilities and stakeholders to explore near-term solutions for CSP projects that include:

- Encourage the utilities to provide more information about the areas of the system that can interconnect CSP projects with the lowest network upgrades.

[9] On January 31, 2019, the Commission help a Special Public Meeting to receive stakeholder input on PURPA Implementation in Oregon. At the Commission's direction, Staff will open an investigation into key issues identified in the Special Public Meeting. More information is available at: http://oregonpuc.granicus.com/GeneratedAgendaViewer.php?view_id=1&clip_id=367

- Consider contracting an independent engineering review of utility interconnection study process and methodologies to identify any available improvements for estimating network upgrades and costs.
- Consider an independent engineering review process through which CSP Project Managers can verify and dispute the results of utility interconnection studies.
- Explore a temporary rulemaking to mitigate network upgrade costs for CSPs, such as aligning Oregon's small generator interconnection cost allocation policies with the policy for certain FERC jurisdictional projects that reimburses small generators for network upgrade costs.

Staff will continue to update the Commission on the status of its efforts to identify near-term opportunities to mitigate interconnection barriers for CSP projects, including a status update no later than April 2019.

Conclusion

PA Selection
A contract for PA services is finalized and circulating for signatures. Staff plans to notify the UM 1930 service list when the contract is executed and update the Commission at a Public Meeting with available details about the timing and structure of CSP implementation efforts to be performed with the PA.

Cost Recovery
Staff is currently working with PAC and PGE to prepare tariffs to collect start-up costs from ratepayers that will be filed when the PA/LIF's costs and utility requirements are known.

RVOS Phase II Completion
The Commission issued Order Nos. 19-021, 19-022, and 19-023 completing Phase II of the RVOS proceeding, adopting RVOS calculation methodologies for PAC, IPC, and PGE respectively, and directing the three utilities to file revised RVOS values by March 18, 2019 along with additional revised values for specific elements by July 18, 2019. Staff will work with the PA and stakeholders to develop transition plans from the interim alternative bill credit rate to a bill credit rate based on RVOS during PIM development and/or other implementation work streams identified with the PA. Staff will update the Commission on the status of RVOS transition planning efforts once underway.

Update from the Subgroups
The Project Details and Low Income subgroups continued to meet in the second half of 2018. The Project Details subgroup report is provided as an attachment to this memo. The Low Income subgroup report will be provided as a consent agenda item for the

February 26. 2019 public meeting. The subgroups are focused on finalizing resources that will be provided to the PA/LIF to support development of the PIM and other implementation activities.

Staff response to Subgroup questions regarding QF designation
In consultation with the Department of Justice, Staff provided clarification to the Project Details subgroups that CSP projects must interconnect with the utilities as QFs. Staff plans to begin working with utilities and stakeholders to identify near-term opportunities to mitigate costs and other barriers for CSP projects, while coordinating with broader efforts to identify solutions to the underlying issues associated with small generator interconnection.

Staff will continue to update the Commission on the status of its efforts to identify near-term opportunities to mitigate interconnection barriers for CSP projects, including a status update no later than April 2019.

PROPOSED COMMISSION MOTION:

Informational filing - no recommendation.

Project Details Subgroup – 1-11-2019

Re: Record of 2018 Discussion Topics, including Recommendations and Important Considerations

Overview

The Project Details Subgroup met 8 times during the second half of 2018, totaling 9.5 hours in meetings. The group made significant progress addressing numerous critical topics relating to project development and certification, and administrative requirements associated with program participation. Meetings were organized and led by the Oregon Solar Energy Industries Association (OSEIA) and included active engagement by the Commission Staff, utilities (Pacific Power, PGE, and ID Power), solar industry (representatives and members from both OSEIA and the Coalition for Community Solar Access (CCSA)), and other stakeholder groups and individuals with an interest in Oregon's community solar program.

Importantly, the voluntary time dedicated by all those involved in the Project Details Subgroup is greatly appreciated and resulted in recommendations and considerations that should serve as a foundation to many of the components anticipated in the Implementation Manual. The effort was (and is) intended to expedite the Program Administrator's ability to complete the program design as soon as possible.

This cover letter summarizes the topics that were covered and the structure and format of input that was provided by the Subgroup. However, the actual input provided by the Subgroup can be found in the Attachments, or more preferably, in a Google Sheet which served as a living document for the group (found here - https://docs.google.com/spreadsheets/d/1RqLmnejdbrAMD8Td7nMCH82CYSV7CReshZ5v2X98VzE/edit#gid=679307985). Before discussing that framework, several notable project development issues are called out in this letter.

Notable Issues for Project Development

Although the Project Details Subgroup worked methodologically through the list of primarily Implementation Manual items outlined in the table further below, there are several important issues already impacting project development which deserve being highlighted. These include:

- **30% Investment Tax Credit (ITC) stepdown at the end of 2019.** The Federal ITC drops from 30% in 2019 to 26% in 2020. Small utility-scale solar development works on long timelines (see Appendix A of PUC Staff Report from Feb. 26, 2018[1]). The 30% ITC is becoming increasingly out of reach for some would-be community solar developers, particularly those that haven't yet been willing to risk investing in the market due to uncertainty with program costs and requirements.
- **Pacific Power capacity constraints.** The first two Project Details Subgroup meetings in 2018 focused almost entirely on concerns with grid capacity availability and interconnection costs in Pacific Power territory. Specifically, developers flagged that interconnection costs for "network resource" projects are extremely high and economically infeasible for most or all otherwise viable locations within Oregon's Pacific Power service territory due to the interconnection queue capacity exceeding local and/or regional load. This represents a block to community solar development for Pacific Power customers and deserves a concerted investigation into the

[1] https://edocs.puc.state.or.us/efdocs/HAU/um1930hau165819.pdf

problem and potential solutions. Relatedly, Staff was tasked with determining what is allowed (from a legal and policy perspective), with regards to: 1) whether community solar projects need to be Qualifying Facilities (QFs); and if not, 2) whether they have the option to be either a Network Resource or Energy Resource. The implications of this are that "energy resource" projects may be able to avoid some of the costly transmission upgrade costs. Finding a resolution here could also impact the ability to leverage the 30% ITC.

- **Willamette Valley permitting challenges.** Solar development in PGE territory is facing a different issue relating to the permitting of solar facilities. At least one county has essentially halted solar permits from being issued and another is currently on hold as it considers new review criteria. Even more significantly, the Department of Land and Conservation Development has proposed rules that would effectively ban solar development on "Class I and II soils" which account for a massive swath of land in the Valley. The Land Conservation and Development Commission will be considering this proposal on January 24, which could have major implications for community solar development in PGE territory.

The Topics

The full record of consensus items, areas of consideration, and specific input by stakeholders are all captured on this Google Sheet, titled Project Details Topics and Discussion Record_2018 (found here: https://docs.google.com/spreadsheets/d/1RqLmnejdbrAMD8Td7nMCH82CYSV7CReshZ5v2X98VzE/edit#gid=679307985). Attached is a PDF version of the "Topic Table", which is the first and most important tab of the Google Sheet. Note that the attached version omits a far right-hand column used for outstanding questions relating to the topics (those questions are included in the Google Sheet version).

The "Topic Table" is organized by Topic, under which there are Subtopics with associated questions directed at the Subgroup. The Topics and related Subtopics are summarized in this table.

Topic	Subtopic
Project Manager Registration	• Registration process • Standard of Conduct
"Pre"-pre-certification	• "Pre"-pre-certification customer engagement • Transparency of market activity prior to pre-certification
Pre-Certification	• Project eligibility based on market classification • Application requirements • Changes to project during 18-month period (post pre-cert.)
Project Siting	• Co-Location • Co-Location exemptions • Project splitting • AC vs. DC
Participant Eligibility	• Customer definition • Affiliate definition
Program Queue	• Queue process for initial/interim capacity allocation • Limits on Project Manager participation • Transition between interim capacity to remaining "initial capacity tier" • Transition between "initial capacity tier" and successor tier
Utility Participation	• Level playing field • Cost recovery transparency

Recommendations and Records

This cover letter does not attempt to summarize all the outcomes captured in the Google Sheet. Instead, readers are directed to the Google Sheet (and/or Attachments) to get a full understanding of each topic, subtopic, and the related questions and responses that were produced by the Subgroup.

While Subgroup participants were provided an ongoing opportunity to provide individual perspectives and responses to the topics and associated questions, it was not until that Topic and/or Subtopic was sufficiently discussed during one or more of the meetings that an official response was recorded. Those records were captured in the Topic Table as either "SUBGROUP GENERAL CONSENSUS ITEMS" (highlighted green) or simply "SUBGROUP RECORDS" (highlighted yellow). "CONSENSUS ITEMS" are responses (i.e., recommendations) in which the entire Subgroup supports, with no objections. "SUBGROUP RECORDS" are responses which provide valuable input and considerations, but which do not provide clear recommendations. Notably, the "SUBGROUP RECORDS" are typically not areas of major disagreement, but instead lack a strong enough opinion or understanding to produce an official position/recommendation.

Alternatively, there are several Topics/Subtopics (see Program Queue and Utility Participation) which had little to no discussion from the Subgroup due to time constraints and, therefore, only individual input is provided and recorded on the Topic Table.

Google Sheet - Additional Tabs

The Google Sheet includes additional tabs that are intended to either:

- Provide a quick reference to useful information (also attached) related to several topic areas
  - PM (Project Manager) Registration – this framework is a CONSENSUS ITEM
  - BETC Location Requirements – supports considerations regarding "Co-Location" rules
  - OR (Oregon) Law Definitions – supports considerations regarding "Co-Location Exemptions"
  - ETO Trade Alley Overview – could provide considerations for the Standard of Conduct
- Provide an archive of saved versions of the Topic Table at various points during Fall 2018 (i.e.,11/27/2018; 11/12/2018; 10/16/2018). Includes individual input from stakeholders ahead of meetings where responses were ultimately consolidated

For any questions relating to this cover letter or the attachments or Google Sheet, please contact: Charlie Coggeshall at charliecoggeshall@gmail.com / 415-595-6119.

NOTE - Colored boxes denote discussions that have occured at the broader stakeholder level, however individual Stakeholders are welcome to submit additional input directly on this sheet as well (just include credit).
Yellow: Denotes topic that has been disucssed by the Subgroup, and although considerations surfaced no affirmative consensus recommendation was produced.
Green: Denotes topic that achieved consensus by Subgroup.

Topic	Subtopic	Rule requirement?	Issue to solve in Manual?	Subgroup discussion record, and stakeholder input/comments (please include name or organization with any comments)
Project Manager Registration	**Registration process**	*"Project Manager must register with the Program Administrator"* *"project manager" is defined in legislation as "entity identified as having responsibility for managing the operation of a community solar project, and, if applicable, for maintaining contact with the electric company that procures electricity from the" project.*	Is there a standard practice to follow in Oregon?	SUBGROUP GENERAL CONSENSUS ITEM (10/10/2018): The subgroup was comfortable with recommending the framework outlined for the Project Manager registration and ongoing committments provided in the tab within this sheet titled: "PM Registration."
			Does the project manager need to own the project? Would there be only one registered project manager for each project? What about when the management of the project itself (i.e., O&M) is different than the entity managing subscribers?	SUBGROUP RECORD (10/10/2018): The subgroup was comfortable with the notion that a Project Manager did not need to be the legal "owner" of the project (e.g., utilities talked about tentative plans to now own projects (use PPAs instead), and in 3rd party development equity/financing partnerships can alter the "legal" ownership over time). However, the Project Manager is the entity responsible for submitting the pre-certification and certification applications and would also be the primary point of contact for the PUC and Program Administrator. The Project Manager would be able to subcontract elements within the project (EPC; O&M; marketing; customer acquisition; etc.), however accountability would remain with the Project Manager (i.e., subcontractors would be an extension of the Project Manager). Note - The PUC Staff plans to further investigate considerations around the concept of project ownership.
	Standard of Conduct	*"Project Manager must comply with the standard of conduct established by Commission Order"*	Need guidance	SUBGROUP RECORD (10/10/2018): The subgroup did not produce concrete recommendations regarding the development of a standard of conduct, beyond highlighting the potential value in seeking out templates or models, such as SEIA's' Solar Business Code.
"Pre"- pre-certification	**"Pre"-precertification customer engagement**	*"Once the Commission pre-certifies a project, the Project Manager may execute contracts with participants for ownership or subscription interests."*	Not entirely clear if there's regulation of customer acquisition/contact prior to pre-certification.	SUBGROUP GENERAL CONSENSUS ITEM (10/10/2018): The subgroup agreed that interactions between prospective customers and prospective project managers (not yet registered) is not something that can or should be regulated, though Staff flagged that there will be public communication prior to program launch with a disclaimer that the program is not yet registering Project Managers. Once a Project Manager is officially registered, there may be defined limits with regards to the characterization of program or project representations/claims that could be made (likely built into the Standard of Conduct) for both before and after pre-certification. The regulations are relatively clear (860-088-0040-4) that official ownership/subscription contracts cannont be signed prior to pre-certification.
	Transparency of market activity prior to pre-certification	None	Is there transparency into market activity prior to pre-certification?	SUBGROUP GENERAL CONSENSUS ITEM (10/10/2018): With regards to market activity transparency for the public, the subgroup was supportive of not only posting pre-certified projects (protecting sensitive/competitive information - per the regulations (860-088-0020-2-h), but also posting pre-certification 'applications' (e.g., number and capacity of projects being reviewed for each service territory). Updates should occur frequently, if not in real time. The names and basic contact details of registered Project Managers should also be posted. Publicly posted utility interconnection queues should also provide a public data point for at least eligible community solar projects.
				SUBGROUP GENERAL CONSENSUS ITEM (10/10/2018): With regards to market activity transparency for the Program Administrator, the subgroup was generally OK with requiring Project Managers to provide, within their registration, a high-level outline of their plans and ambitions in the market. See the PM Registration tab for a description.
			Should there be a PA hosted "clearing house" website? "If so, what should it include?	SUBGROUP RECORD (10/24/2018): The subgroup was receptive to industry position that posting basic information regarding project managers and projects in the program was reasonable (e.g., links to associated contact points, project size, and maybe subscription levels if not administratively burdensome.), but would not want to share pricing information. Pricing should be confidential between the Project Manager and customer. An attempt at provide a public comparison could fail to capture each project's full value proposition and create market biases. Instead, this site could be used as a starting point for someone trying to identify and contact the different projects and Project Managers in the market. That said, stakeholders also called out that consumers may prefer having more information in one place.

	Project eligiblity based on market classification	*"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*	Unclear if projects need to be registered as QFs, and/or whether they need to be designated as ER or NR.	SUBGROUP RECORD (7/26 & 10/24, 2018): Lengthy discussion on this topic without resolution. Concerns relate to cost recovery of transmission upgrade requirements, particularly in PAC territory. The PUC Staff is working with their legal team to make a determination (or recommendation to PUC) on how this should be addressed. OSEIA/CCSA recommends allowing for flexibility in the program - i.e., default would be that projects are QFs but it's not mandatory. PGE seemed to think the industry proposal was reasonable. PAC is investigating independently.
		None	Should there be special treatment for any of the application requirements for smaller (i.e., 360 kW or less) and/or low-income projects?	SUBGROUP RECORD (10/24/2018): Several stakeholders voiced concern for smaller (sub-360 kW) and/or more unique projects (e.g., low-income) and that they could potentially be held to a different standard that takes into account project costs and their Project Manager/organization's resources and capabilities. Areas called out where this might be achieved included interconnection requirements and co-location requirements: see related discussion records below. Ultimately, any aid for these smaller projects should not enable gaming of other rules and/or compromising consumer protection requirements. It was determined that special treatment for low-income projects should be explored separately, e.g., in the Low-Income Subgroup and/or with the Low-Income Facilitator.
		"Permitting requirements and status of compliance"	Need guidance	SUBGROUP GENERAL CONSENSUS ITEM (10/24/2018): The subgroup recommends requiring non-ministerial/discretionary -type permits for pre-certification to ensure the project will not get held up or terminated after pre-certification. This would also provide transparency for Project Managers evaluating the pre-certification requirements. There was some receptiveness to simply "demonstrating" a clear path to obtaining those permits (e.g., conditional use permits), though the administrative burden on the PA and uncertainty for Project Managers makes this less desirable. This could be re-considered as needed.
Pre-Certification	**Application Requirements**	*"All documentation relevant to the interconnection process as provided in OAR chapter 860, division 82"*	Need guidance on actual Interconnection prerequisites for applying into program.	SUBGROUP GENERAL CONSENSUS ITEM (11/7/2018): The Subgroup agrees that System Impact Study should be the minimum interconnection status for Tier 4 projects, and that a Interconnection Agreement should be required for Tier 2 projects (as designated by the respective utility process).
				SUBGROUP GENERAL CONSENSUS ITEM (2017): Subgroup recommended that existing projects (already in the interconnection queue prior to program launch) should be eligible to apply into program (assuming they have SIS or higher).
				SUBGROUP RECORD (11/7/2018): Though the Subgroup originally recommended against creating additional interconnection requirements for the community solar program, OSEIA/CCSA voiced concern for PAC territory interconnection costs and the potential need to accomodate community solar projects. PAC was comfortable with saying there should not be additional requirements and was open to potential options for making it less burdensome, but the Subgroup did not identify any immediate recommendations.
		"Participant acquisition approach"	Need guidance.	SUBGROUP RECORD (11/14/2018): The Subgroup was generally OK with allowing this to inform general strategy/approach that the Project Manager intends to take with regards to marketing, partnerships, and anticipated product types. This summary can in turn take the place of submissions of marketing materials and contracts. The information requested here should be brief and clear, with an aim to not confuse applicants and trigger arbitary or ambiguous responses. Confidentiality should always be protected.
		"Proposed marketing materials"	Need guidance. This could be administratively burdensome for Project Managers and the Program Administrator and create an arbitrary criteria in the application process.	SUBGROUP GENERAL CONSENSUS ITEM (11/14/2018): After much discussion, the Subgroup was supportive of a suggestion submitted by the Energy Trust of Oregon, which was: 1) Project Managers provide information about their planned marketing channels and any paid (or anticipated) third parties that will be conducting marketing/customer acquisition on behalf of the project; 2) If there are concerns, the PA can reserve the right to request copies of marketing materials. The Subgroup agreed that it is unnecessary to have a wholesale requirement that all marketing materials be required for submission by every applicant at pre-certification, or any subsequent updated materials post- pre-certification. Instead, clear guidelines for what's expected of those materials (e.g., a Commission-approved disclaimer (ORS 860-088-0090(3)), along with guidelines for Project Manager engagement of customers (e.g., captured in Standard of Conduct) and consumer protections more generally (e.g., captured in Implementation Manual) are sufficient so long as the Program Adminsitrator reserves the right to review materials upon request. Confidentiality should always be protected.

Pre-Certification (continued)	**Application Requirements (continued)**	*"Proposed forms and standard contracts for ownership interests and subscriptions"*	Need guidance. Project Managers will not be comfortable sharing confidential terms and conditions.	SUBGROUP RECORD (11/28/2018): The Subgroup was generally OK with following a similar approach as that used for the marketing materials explained above. In essence, rather than require the submission of every potential contract from each applicant and/or updated contracts after pre-certification, instead provide clear guidelines to those Project Managers on expectations for the contracts while also giving the Program Administrator discretion to review materials upon request. Consumer protection guidelines and expectations can be reinforced via in the Project Manager Standard of Conduct, Implementation Manual, as well as via the Commission-approved checklist (i.e., standard disclosure). The Subgroup agreed that the primary emphasis for protection here was for residential customers, and that the objective is not to control the value proposition or overly prescribe the details of a contract but more to ensure the terms and conditions are clear and transparent. Confidentiality of any contracts shared with the Program Administrator should always be protected. The Subgroup also agreed that creating a contract "template" that could be offered as an example and/or option for Project Managers to adopt would be beneficial, though the group agreed its use should not be mandatory. The Subgroup also touched on questions relating to penalties/enforcement of contract guidelines, and how the PUC may (or should?) have more authority over penalizing Project Managers rather than invalidating actual contracts.
		"Plan for meeting applicable low-income capacity requirements"	Need guidance	SUBGROUP RECORD (11/28/2018): The Subgroup briefly discussed this component and generally agreed that requirements here should not be overly prescriptive, and that the program should allow the market to innovate. Specifically, there was reference to the possibilty of the Low Income Facilitator creating plug n' play option(s) for Project Managers to utilize in meeting the low-income participation requirements which may be great for some Project Managers while others may be interesed in pursuing their own means. This raised comments/questions regarding cost recovery of said option(s) and whether costs associated with a standard - program offered - construct should be be recovered by all projects/participants or only those leveraging the option. The Subgroup agreed that driving toward cost efficiencies should be an objective and therefore market competition should be enabled. This issue also raised questions regarding whether the utilities have low-income resources that could/should be shared across the program if it could reduce costs for meeting these targets.
		"Payment of any applicable application fees"	Need guidance on what the application fee is and how it's calculated.	SUBGROUP RECORD (11/28/2018): The Subgroup did not discuss this topic in detail, but it was briefly broached and there is some existing record of input from stakeholders. The Subgroup did not object to the concept that application fees should be calculated based on an assumption that the entire initial capacity tier was applying/applied into the program, with an emphasis on not penalizing first movers in the program. A related concern has been raised here regarding the Program Administrator's ability to recover cost in the early launch time period of the program prior to when projects are actually operating and potential ongoing program cost fees could be deducted from credit rates.
			Deposits?	SUBGROUP RECORD (11/28/2018): The Subgroup agreed it may be reasonable to require a refundable deposit to be required of projects that are pre-certified, which would then be returned at the time of project certification (with maybe some exception made for force majeure, or other legal classification). The aim here is to provide greater assurance that projects move forward after being pre-certified. Reference was made to Oregon's BETC program as a potential example for this deposit cost and construct. An example value offered was $20 per kW as a deposit, refundable upon project operation. That said, there may need to be consideration or option for Project Managers with legitimate projects and plans but which struggle to produce the deposit funding level.
	Changes to project during 18 month period (post-precert)	*"The Project Manager must seek Commission approval of any modification to a pre-certified project relating to project elements set forth in the Program Implementation Manual."*	What if project fails to come online due to land issue, bankruptacy, etc.?	OSEIA/CCSA: Part of solution here could be to raise pre-certification qualifications - e.g., require actual non-ministerial permits as opposed to just "significant progress" toward obtaining those permits. There could also be milestone/check points that track the progress of the project's being developed/installed. If a project is not hitting it's milestones it risks being kicked out of program so that program capacity can be made available to more viable projects. Lizzie Rubado, Energy Trust: Agree that milestones shoudl be a part of the program (and are standard practice) and the program should be informed of any signifigant modifications to projects.
			Can the Project Manager role change hands after pre-certification? What about the subcontractors under that PM?	

Project Siting	Co-Location	*"Co-location means two or more projects that exhibit characteristics of a single development, such as common ownership structure, an umbrella sale arrangement, revenuesharing arrangements, or common debt or equity financing. Projects are not considered co-located solely because the same person provides tax equity financing for the projects. Co-location of projects is not permitted within a five-mile radius.."*	Is this sufficient? Is more guidance/clarity needed?	SUBGROUP RECORD (11/14/2018): The Subgroup was good with the clarifying assumption that as long as there are no joint development or revenue sharing agreements between two or more projects located within 5 miles of eachother, it was OK if they happen to be using the same EPC, marketer/customer acquisition contractor, or other sub-contractors. The Subgroup agreed additional insights and "tests" for co-location could potentially be sourced from Oregon's past BETC program (see tab: "BETC Location Requirements"). The subgroup was sensitve to not wanting to conflict with the various types of partnerships and LLCs that may be unique to community solar and the potential for overlap of market players. There was some disagreement as to whether a Project Manager alone could trigger a co-location violation if it was managing two or more projects within 5 miles (that didn't otherwise meet the exemption requirements). The Subgroup agreed this may not be a black and white situation if the Project Manager was not involved in the development of the projects (i.e., during the point where economies of scale could be achieved), though could also create administrative and transparency issues if not spelled out specifically.
			Need to clarify whether co-location is allowed if resulting in above 360 kW for projects seeking small project carve-out capacity?	SUBGROUP RECORD (10/24/2018 and 11/7/2018): The Subgroup swayed back and forth on this topic. Initially, some advocates and industry members recommended special treatment for small projects to make them more economically viable, such as waiving some of the co-location requirements or allowing for 3-4 projects to be co-located. However, additional voices from industry and the uility sector were opposed to this concept and called out that if the small projects do not pencil, they likely need some other policy support (e.g., different credit rate or incentive), rather than allowing for co-location and i.e., larger projects. There was also concern for gaming in this regard, as well as in exploiting the municipality exception (e.g., leveraging small project carve-out once the larger project capacity is tapped out). That said, there did appear to be general agreement that it would be reasonable to reduce the distance requirement (e.g., rather than 5 miles minimum distance, a kilometer, etc.).
	Co-Location Exemptions	Co-location is not permitted, UNLESS: "(a) *The aggregate nameplate capacity of the co-located projects is three megawatts or less; or (b) The co-located projects are all sited within a single municipality or*	Need to define "single municipality or urban area"	SUBGROUP RECORD (11/7/2018): The Subgroup was comfortable with the notion that "municipality" and "urban area" should refer to a city or town boundary as defined by that city/town ordinance. Everyone agreed general intent was to encourage projects close to load and help counter the higher property costs of cities. There are definitions that could potentially be leveraged from the PUC and other Oregon state glossaries - see tab titled: "ORLaw Definitions", however most of these seem to incorporate "counties" as potentially viable municipalities which the Subgroup agreed was not the intent. The only outstanding question is whether further definition/clarification is needed regarding city/town limits.
	Project splitting	None	Can a 3 MW project be splintered off from a larger project in order to participate in the program?	SUBGROUP RECORD (11/28/2018): There are two aspects of this question: 1) what are the technical considerations for splitting a project at various stages of development (e.g., as it moves through interconnection queue); and 2) is this something that should or should not be allowed from a policy perspective? On the latter, the majority of the group was comfortable with allowing this to occur as long as the developer/project manager is willing to navigate the technical challenges, though this was not a consensus item due to some dissenssion on the grounds that splitting projects would not follow the intent of the Program Rules and could create unfair economic advantages for larger projects. Further, on policy, the point was made that the program should only be eligible for "new projects" (not currently operating), to which there was no objection by the Subgroup though also no discussion. For clarification, projects already in the interconnection queue and/or under development prior to the program launch are still considered "new". Only projects that are currently physically operating would not be eligible. On the former question regarding technical considerations, the utilities offered the following observations: 1) If a project size is changed then any negotiated PPA (based on initial size) would be nullified and must be re-negotiated (~30 days). 2) The interconnection guidelines referenced in the community solar rules pertain to projects that are 10 MW or less, therefore a project moving through the interconnection queue that is larger than 10 MW would not be eligible to splinter off a 3 MW or smaller project for community solar. 3) A project application that is in the interconnection queue and has not yet obtained a Facilities Study could fairly easily be splintered into more than one project (adding up to the initial project's size) without interrupting the queue position because studies up to that point (e.g., SIS) are focused on the aggregate amount hitting the grid on that circuit. 4) If two projects are QFs and owned by the same entity they are supposed to be at least one mile apart (per FERC rules).
	AC vs. DC	*"Nameplate Capacity"*	Confirm this refers to AC.	SUBGROUP GENERAL CONSENSUS ITEM (11/7/2018): Subgroup agreed this refers to AC.

Participant Eligiblity	**Customer definition**	*"At least 50% of nameplate capacity of each project must be allocated exclusively for ownership or subscription by residential and small commercial customers."*	Need definitions for these customers.	SUBGROUP RECORD (11/14/2018): The Subgroup was OK with using the following utility rate schedules at the time of subscription for determining eligiblity, e.g., for residential use: PGE = Schedule 7 / PAC = Schedule 4; and for small commerical (small non-residential) use: PGE = Schedule 32 / PAC = Schedule 23. That said, some industry members have suggested that rather than using the rate schedules use a subscription size limit, like 30 kW, which has been the common practice in other markets across the country (e.g., MA and IL). This could increase participation opportunities for medium sized commercial companies that may otherwise not be targeted as anchor tenants.
			Can participating customers also be participating in other utility programs (e.g., NEM, VIR, etc.)? What special considerations are needed?	SUBGROUP RECORD (11/14/2018): The Subgroup was OK with permitting customers that are already participating in other programs - such as NEM, for example - to also participate in the community solar program. It was also detemined that annual load - in calculating subscription size eligiblity - should be based on the net amount, accouting for reductions in load from NEM or other systems. That said, additional questions/considerations were raised with regards to the order in which credits from the different programs are applied. This may be a bigger issue for commercial customers, as has been discussed at some level in the Utility Data Exchange Subgroup. This discussion also triggered concerns regarding equal pay customers (e.g., low-income customers) and how they would be treated/credited in the program. The subgroup agreed that overly complicated mechanisms could unnecessarily increase administrative costs for the program.
	Affiliate definition	None	Need to define "affiliate".	SUBGROUP RECORD (11/7/2018): Subgroup agreed that there may be fairly straightforward ways/defintions in determining "affiliations" within corporations, however the lines might be more blurry with regards to public entities (federal, state, and local). The group agreed more research was needed in this area as some public entities - e.g., the City of Portland - is huge, but has many generally unrelated entities that could want to participate in the program. There is sensitivity to undermining the beneficial roles that these large public entities could play as participants in the program.
			Need to confirm that this refers to 4 MW in each service territory, not the program overall.	SUBGROUP GENERAL CONSENSUS ITEM (11/7/2018): The Subgroup agreed that intention was for the 4 MW limit to pertain to each separate service territory, rather than entire program.

Program Queue	"Soft" launch for program	None	Should the program launch by a certain date, even if the full infrastructure is not built out?	SUBGROUP RECORD (11/28/2018): The Subgroup was generally supportive of the concept of utilizing a "soft launch", that allowed projects to become pre-certified prior to the full program design and infrastructure being completed. The ongoing delays in bringing on a Program Administrator and the amount of work that awaits it has raised increasing concerns regarding the ability to leverage the 30% ITC (before it steps down in 2020). There's concern that not only will the infrastructure build out take a long time but also the establishment of an Implementation Manual. Some stakeholders suggest that the program should launch even prior to the Implementation Manual being completed, which in turn could aid in informing that design. Others note that if the Implementation Manual is not complete, it will be important to determine what program design factors need to be guaranteed at the time of submitting an application (e.g., primary program economic components: credit rate; admin cost; and low-income cost). At least one stakeholder also noted that the enabling legislation for this program (along with changes to other renewable energy programs) deemed the need for immediate action (SB 1547, Sec. 32), which clearly conflicts with the pace of program rollout to date.
	Queue process for initial/interim capacity allocation	None	Assuming all pre-certification requirements are met, what's the process for making the first cut?	OSEIA/CCSA: Due to tight economics, project development hurdles (permitting in PGE territory and interconnection in PAC territory), and the numerous requirements associated with pre-certification, it's likely that first-come, first-serve is a sufficient approach to releasing the program's interim capacity allocaiton. That said, given the limited about of capacity that will be released and experience from other markets where lotteries and other mechanisms have been used to avoid gaming and to filter huge numbers of application submissions, it's possible Oregon should consider a Plan B. Until the level of uncertainty around program/project economics is diminished it will be difficult to ascertain how high demand will be in the program.
	Limits on Project Manager participation	None	Should there be a limit on the amount of capacity any single Project Manager can have in the program? Or at least a limit for a specified period of time?	OSEIA/CCSA: Some in the industry have recommended there be a limit e.g., 50% of capacity allocation can go to a single Project Manager, at least initially. If more applicants do not take advantage of the remaining capacity limit is removed. That said, industry is also hesitant to carve up the initial capacity tier in more ways.
	Transition between interim capacity to remaining "initial capacity tier"	None	What happens to projects in the queue that don't make the first capacity cut?	OSEIA/CCSA: Industry needs transparency into this issue as it can impact the risk level of applying. Generally, it seems reasonable to maintain queue positions and give projects at the top of the queue first right of refusal to stay in or get out based on the successor credit rate. Though, as mentioned below there should really be transparency at the program launch with regards to what to most likely expect with regards to any potential rate change.
		None	Concern that successor capacity could get hung up by lack of interest in one capacity allocation category (e.g., small projects in PGE territory).	OSEIA/CCSA: Industry feels that the delay in getting the PA on board has defeated part of the purpose of the "interim capacity allocation", which was in part to support development that could begin in 2018, along with a program launch in 2018 - all to meet the 30% ITC. The continued delay undermines the initial goal of the 40 MW allocation. Inudstry suggests a larger allocation if not the entire initial capacity tier be released upon program launch. That said, if there really is going to be a transition between the initial 40 MW and successor capacity there should be a time element, not just capacity allocation, in triggering the release of the succesor capacity. E.g., the market shouldn't have to wait until all 40 MW is allocated if it appears to be stalling in one sub-category of the interim allocation. **Response to Lizzie** - Industry would prefer that successor capacity be triggered based on pre-certification dates, rather than certification. The market should maintain momentum and not be disrupted by long delays waiting on certification. We should also remain cognizant of declining ITC levels and the ability to benefit from federal funds. Details would need to be figured out for cases where projects failed to reach certification - i.e., would capacity be re-released at original credit rates or successor credit rates. Lizzie Rubado, Energy Trust: Has there been discussion whether the capacity within a tier must be certified (commercially operational), pre-certified (under development) or something in-between to trigger a transition to a subsequent tier? This will have a signifigant impact on the timimng of when additional capacity will become available for development.
		None	Concern for transparency into successor credit rate.	OSEIA/CCSA: The successor credit rate needs to be determined ASAP in order to maintain a steady market between the "interim" capacity allocation and remaining "initial capacity tier". The process for determining this rate should begin in parallel to the implementation manual development.
	Transition between "initial capacity tier" and successor tier	None	Process for projects that do not make cut into initial capacity tier.	SUBGROUP RECORD (Dec. 5, 2017): Subgroup discussed this issue including concern of losing queue position.

Utility Participation (as Project Managers)	**Level playing field**		What advantages do utilities have and is there a need to level the playing field? If so, how?	OSEIA/CCSA: Utilities have many potential advantages in: land ownership; access to substation maps/grid information; control of interconnection upgrade/cost requirements; control of interconnection queue/timelines; access to all customer data; existing relationships and communication channels with customers that can be leveraged for marketing and acquisition; and, generally, balance sheets that could support projects and avoid financier/investor requirements and associated costs. Though industry suspects the utilities will always have an advantage, potential ways to help level playing field include: - limit the amount of capacity the utilities can leverage in the program; - not allow utilities to actually develop and own their own projects to avoid the potential land and grid advantages/conflict of interests; - require utilities to share substation maps and similiar insights into the status/activity of their grids; - make resources available to all project managers with regards to marketing/acquisition tools like customer data, bill inserts, etc.; - utilities could be prohibited from marketing via their standard communication channels (e.g., not via bill inserts, etc.), and required to advertise program generally and point to a site where all project managers and projects are listed (including the utility projects).
	Cost recovery transparency	*"An electric company must obtain Commission approval of any applicable tariffs required by these rules, including the rate recovery of any expenditure for project development and administration if the electric company is acting as Project Manager."*	How will costs be transparently accounted for so that projects are not rate-based?	TBD

Project Manager Registration and Ongoing Commitment (endorsed by the Subgroup on 10/10/2018)

Step	Objective	Notes
Initial Registration: Set a relatively low bar for getting registered.	Enable access by a variety of potential managers.	Should not set the bar so high as to deter smaller developers or community groups from pursuing a project.
	Prevent administrative burden and redundancy.	Registration shouldn't have too much overlap with the code of conduct and other consumer protections which are addressed in the stages involved in actually applying for project pre-certification and certification.
	Collect all needed contact information.	E.g., business name and location; point of contact; license to operate in Oregon (if a business?); tax ID; etc.
	Sign, or make some commitment to abide by an established standard of conduct for Project Managers.	Standard of conduct.
	Get some sense of market plans and/or ambitions.	This is not binding, but more for informational purposes (where and how much capacity are projects, types of customers, general business model, potential business partners (or types of partners – customer aggregators, etc.)
	Ensure project managers are familiar with the program implementation manual and have reviewed training materials.	Maybe participation in a training webinar?
Ongoing Commitments: Once registered, meet initial requirements associated with pre-certification and certification, and continue to abide by all ongoing standards set forth in code of conduct.	This is where project managers are held to a higher standard for participating in the market, with the ultimate goal to protect consumers without overly interfering in project diversity and innovation.	

BETC

330-090-0120 (2)(b)(B) https://secure.sos.state.or.us/oard/displayDivisionRules.action?selectedDivision=1101

(B) Applications for facilities using or producing renewable energy resources, or facilities listed as renewable energy resources as defined under ORS 469B.130 will be determined to be a single facility, despite the number of applications, owners or construction phases, if three or more of the following apply:

(i) The facility is located on one or more adjacent parcels of land or parcels;

(ii) The facility has been recognized in a license or permit as a single facility by a federal, state, county, city or local authority including, but not limited to siting council, state or local boards or commissions, or the facility has obtained or applied for siting or land use approval and other applicable permits, licenses or site certificates as a single facility or on a single application;

(iii) When the facility is designed to generate energy, the construction of the facility is performed under the same contract with a general contractor licensed under ORS 701 or multiple contracts entered into within one year of each other with one or more general contractors licensed under ORS 701. If facilities will be completed in phases over time, the applicant must demonstrate that each of the phases of the facility would independently qualify as an eligible facility and that each phase of the facility is not interdependent in purpose or the manner in which it will be owned, financed, constructed, operated, or maintained or the facilities or phases of the facility will be determined to be one facility for the purposes of these rules;

(iv) The facility owners have entered into or expect to enter into agreements to share project expenses, personnel, capital investments including generating equipment or other resources related to the facility;

(v) The generating equipment for the facility and the related facility was purchased by the same person or persons who own or operate the facility or have taken action under any of the above factors;

(vi) A facility is connected to the grid through a single connection or multiple connections when there is a shared net metering, power purchase or other applicable transmission agreement; or

(vii) Other factors or considerations which demonstrate that the facility is not a separate and distinct facility based on its

(C) Applications other than those described in subsections (B) will be considered a single facility if three or more of the following apply:

(i) shared ownership of facilities,

(ii) shared location of facilities,

(iii) project permits are issued to a common entity or at the same time or

(iv) a shared contract to construct the facilities.

Term		Source	Link
Municipality	"Municipality" means any city, municipal corporation or quasi-municipal corporation	Oregon Laws - ORS 756 - PUC-Definitions	https://www.oregonlaws.org/ors/756.010
	"Municipality" means any county or any city in this state. "The municipality" means the municipality for which a particular urban renewal agency is created.	Oregon Laws -general glossary	https://www.oregonlaws.org/glossary/definition/municipality
	"Municipality" means any city, municipal corporation or quasi-municipal corporation.	Oregon Laws -general glossary	https://www.oregonlaws.org/glossary/definition/municipality
	"Municipality" means any county, city, town, village, borough, authority, district or other political subdivision or public corporation of this state. "Municipal" means pertaining to a municipality as defined in this section.	Oregon Laws -general glossary	https://www.oregonlaws.org/glossary/definition/municipality
Municipal Corporation	"Municipal corporation" means a: city; county; special district; school district or education service district; corporation upon which conferred powers of the state for the purpose of local government; public corporation, including a cooperative bodey formed between municipal corporations.	ORS 297-405 (Chapter 297 refers to audits of public funds and financial records)	https://www.oregonlaws.org/ors/297.405
	"Municipal corporation" has the meaning given in ORS 297.405 (Definitions for ORS 297.020, 297.230, 297.405 to 297.740 and 297.990) and also includes any Indian tribe or authorized Indian tribal organization or any combination of two or more of these tribes or organizations acting jointly in connection with a small scale local energy project.	Oregon Laws -general glossary	https://www.oregonlaws.org/glossary/definition/municipal_corporation
Urban area	Not defined		
Urban growth boundary	"Urban growth boundary" means an acknowledged urban growth boundary contained in a city or county comprehensive plan or an acknowledged urban growth boundary that has been adopted by a metropolitan service district council under ORS 268.390 (Planning for activities and areas with metropolitan impact) (3).	ORS 197-295 (Urban Growth Boundaries and Needed Growth within Boundaries)	https://www.oregonlaws.org/ors/197.295
Urban renewal area	"Urban renewal area" means a blighted area included in an urban renewal plan or an area included in an urban renewal plan under ORS 457.160 (Exceptions to plan requirements for disaster areas).	Oregon Laws - ORS 457 definitions	https://www.oregonlaws.org/ors/457.010
Urban renewal plan	"Urban renewal plan" or "plan" means a plan, as it exists or is changed or modified from time to time for one or more urban renewal areas, as provided in ORS 457.085 (Urban renewal plan requirements), 457.095 (Approval of plan by ordinance), 457.105 (Approval of plan by other municipalities), 457.115 (Manner of newspaper notice), 457.120 (When additional notice required), 457.125 (Recording of plan upon approval), 457.135 (Conclusive presumption of plan validity) and 457.220	Oregon Laws - ORS 457 definitions	https://www.oregonlaws.org/ors/457.010
Authority of cities in unincorporated area	The powers of an incorporated city to control subdivision and other partitioning of land and to rename thoroughfares in adjacent unincorporated areas shall continue unimpaired by ORS 215.010 (Definitions) to 215.190 (Violation of ordinances or regulations) and 215.402 (Definitions for ORS 215.402 to 215.438 and 215.700 to 215.780) to 215.438 (Transmission towers) until the county governing body that has jurisdiction over the area adopts regulations for controlling subdivision there. Any part of the area subject to the county regulations shall cease to be subject to the two powers of the city, unless otherwise provided in an urban growth area management agreement jointly adopted by a city and county to establish procedures for regulating land use outside the city limits and within an urban growth boundary acknowledged under ORS 197.251 (Compliance acknowledgment). [Amended by 1963 c.619 §10; 1983 c.570 §4]	ORS 215-170	https://www.oregonlaws.org/ors/215.170

ETO Trady Ally Requirements Overview

Program Training

1. Watch the required online solar electric trade ally videos that explain how to apply for incentives, technical requirements, etc. After you've watched all the required videos, you will be asked to complete a short online quiz.

Program Reading

1. Read the Solar Electric Program Guide
2. Read the Solar Electric Installation Requirements

Other

1. Insurance: Trade ally shall have, and must maintain, **state-required workers' compensation insurance** as well **occurrence-based commercial general liability (including contractual liability and completed operations coverage and, if not covered under trade ally's statutory workers' compensation, employers' liability) with not less than $1,000,000 per occurrence for bodily injury and property damage liability, with an annual aggregate limit of not less than $1,000,000.** Trade ally's commercial general liability policy must cover the type of work Trade Ally performs and must include (i) an "additional insured" provision providing that Energy Trust of Oregon, Inc. and its directors, officers and employees are included as an additional insured, and include (ii) cross liability and waiver of subrogation clauses, and (iii) an acknowledgement that in the event of a loss, trade ally's policy will be primary. **Evidence of insurance for the workers compensation and commercial general liability coverages, as described above, must be submitted to Energy Trust, in the form of a certificate of insurance at the time of this enrollment and promptly upon request during the term. The certificate of commercial general liability coverage must clearly identify "Energy Trust of Oregon, Inc." as an additional insured. Trade ally must maintain adequate automobile liability insurance** and, upon request, must promptly provide evidence of such coverage satisfactory to Energy Trust in its sole discretion.
2. Licenses and Compliance with Laws. Trade ally shall comply with all laws and certifies that it has and shall maintain all appropriate licenses, registrations, and certifications for the work it performs, including, but not limited to, **Construction Contractors Board (CCB) requirements** (CCB license is a requirement for solar trade allies) and Washington Contractors requirements, and shall be solely responsible for its noncompliance with said laws, licenses, registrations and certifications.
3. Agree to terms: Trade allies must enter into an agreement with Energy Trust that includes a variety of Terms and Conditions, and requires compliance with the rules, processes and requirements laid out in the Program-specific program guide and installation requirements.

Find relevant links here: https://insider.energytrust.org/programs/solar/program-training/

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.[1] 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.

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

[1] 16 U.S.C. §824.

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.
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> 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.
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> ***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.[2]

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,[3] the Commission would not be able to establish the purchase price or other terms of the sale.[4]

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.

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

[3] 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.")

[4] 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.