Introduction

Staff submits the following comments in order to provide explanation and the rationale behind recommended changes and edits for clarity on aspects of the draft rules where stakeholders have expressed concern. For purposes of the record, below is a summary of the stakeholder events that have occurred during the docket:

1. Stakeholder workshops
   a. August 31 – official docket kickoff, process overview, discussion of topics list
   b. October 13 – Program and project design elements
   c. November 21 – Review and discussion of proposed program scenarios
   d. December 12 – Program certification, administrative roles and responsibilities
   e. February 14 – low-income components (stakeholder driven)
2. Meetings/Hearings
   a. January 23 – Stakeholder comments to the Commission
   b. April 13 – Staff question-and-answer session for draft rules
3. Miscellaneous
   a. Numerous stakeholder one-one-one meetings with Staff throughout the docket
   b. "Roadshow" to four Oregon cities with ETO and other stakeholders

PPA Section

Sec. 22(2)(a)(D) of the law specifies that the Commission must, by rule or order, require electric companies to enter into a 20-year power purchase agreement (PPA) with a certified community solar projects. Most of the generation of the projects will be used to offset the energy consumed by the project subscribers and owners. However, the project manager can sell unsubscribed generation to the utility under a PPA. Proposed rule 860-088-0120 outlines requirements for PPAs between projects and utilities. The proposed rules use the Public Utility Regulatory Policy Act (PURPA) and ORS 758.505 as the construct for these contracts. PURPA and its associated state rules, requirements, and orders from the Commission are well understood by the solar project development community. In Oregon, PURPA allows power to be sold from qualifying facilities on an "as available" basis, among other sale options. This "as available" basis is tied to the current market price, so that at the time of the given sale, pricing will be consistent with the price that would be paid to the project on the open market.

Proposed rules use the "as available" basis as the rate which projects will be paid because the power they will provide under this contract will not be firm and will fluctuate depending on the percentage of the project that has been subscribed. In order to incent project managers to subscribe or sell as many participants as possible, and therefore adhere to the intention of the community solar program, the PPA rate offered under proposed rule 860-088-0120 can only be acquired after 50 percent of the nameplate capacity of a project is subscribed or owned. Once that occurs, then a project may sell up to 10 percent of the nameplate capacity to the utility at the "as available" rate. Any power not subscribed that exceeds the 10 percent cap is donated, at the RVOS rate, to the utility for the purposes of funding low-income participation in community solar projects.

In the previous version of the draft rules, projects needed 90 percent of the total capacity subscribed before a project could receive final certification. Stakeholder feedback indicated that this requirement was too onerous and that the 10 percent limit on capacity that can be sold on the "as available" rate would suffice as a motivation for project managers to prioritize participant acquisition. Staff was receptive to these comments and subsequently lowered the required amount to 50 percent. However, Staff believes a subscription requirement of some amount is necessary before projects can receive final certification in order to maintain program integrity and ensure projects that intend to serve participants are successfully certified. Staff believes the 50 percent value will achieve a balance between lenient enforcement and hopeful adherence to desired program outcomes.

Proposed Certification Requirements

As is implied elsewhere from the content of these Comments and in the rules themselves, Staff envisions a staged process to complete guidelines for certification and determine other program mechanics that will commence immediately following the conclusion of this rulemaking. Accordingly, many of the detailed aspects of the pre and final certification processes will be addressed in those later stages. The rules developed and proposed by Staff are not intended to resolve all aspects of the pre or final certification process; there are several key principles that underlie the rules and will underlie the to-be-completed guideline development effort. Specifically:

- Economic certainty should be assured at the time of pre-certification. This means that upon receiving pre-certification, project managers should understand and have all key costs and credits associated with certification "locked in" for the purposes of signing contracts with program participants. The path forward to an energized, financed project should be clearly understood.
- The certification process should not allow for the "parking" of projects. Rules and guidelines will require that project managers make progress toward completion, and projects that are not hitting important milestones must leave the process.

- Though queues are proposed to be confidential, they will be transparently developed so that project managers are aware of the level of volume of projects currently in the queue, what steps will be necessary to obtain a place in the queue, and how long the manager has to complete each milestone once in the queue.
- There will be reasonable amounts of time available to applicants to remedy deficient applications without being denied approval.
- Fees will be imposed in part to cover third-party administrative costs.

Pre-certification

The pre-certification process reserves program capacity for project managers. As outlined in proposed rule 860-088-0060, once a project is pre-certified the nameplate capacity is counted towards the program capacity tier for the specific electric company in which the proposed project is located. The nameplate capacity is then removed from the capacity tier for that electric company, effectively reserving the capacity. No pre-certification will move forward for a specific without sufficient capacity available. Projects may only retain the pre-certification status for eighteen months, after which projects can lose their place in the queue.

The pre-certification process is intended to create a high bar for project managers, and will require the submission of material sufficient to determine the viability of the program and whether it adheres to the final rules and any additional Commission requirements. Project managers must register and be approved for participation in the program prior to pre-certification of a project. Staff currently envisions project manager registration as minimally involved process. Pre-certification represents a major milestone in the Community Solar project development process, and should result in approvals sufficient to provide justification for financing of the project. Upon pre-certification, all economic variables that are subject to control by utilities or the Commission for a project will be set, including bill credit rates, third party administration charges, and utility PPA values. This will provide project managers with the certainty necessary to start effectively marketing the project to subscribers and owners. After this stage there will be sufficient certainty so that projects may be financed. Most importantly, pre-certification will result in projects that minimize the risk for potential customers and are more likely to deliver satisfactory service.

The proposed pre-certification section, 860-088-0150, does not outline all of the requirements for pre-certification and does not enumerate all of the materials or documentation that must be provided by an interested project manager in order to achieve pre-certification. The rules do provide a list of some of the information needed, including project location, project permitting, a project overview, a plan for the end of the project useful life, interconnection documentation, and plans for meeting the low-income participation requirement as well as plans for acquiring customer subscriptions. At pre-certification, project managers must also submit proposed forms and contracts for customers. These general categories are the foundation in which Staff and the program administrator can design requirements and subsequently modify them as needed.

The specific requirements of the pre-certification process and the content of the pre-certification application will be further developed and refined through the creation of the program implementation manual and through Commission order. As indicated in workshops and communications with stakeholders, Staff envisions a staged process for program development that begins with adopted rules and is followed by the issuance of an RFP for a third party administrator, the selection of a third party administrator, the development of detailed implementation manuals for external and internal use, a Commission process to approve the implementation manuals, and Commission rulings on other detailed implementation questions, as stipulated in rules. These steps are necessary to stand up a durable and sustainable program and instill confidence in participants.

Final Certification

Final certification is intended to be achievable based on clearly understood and expected milestones. Under the proposed rules, the third-party administrator will submit to Commission Staff final certification information and the Commission will issue or deny final certification based on a narrow set of qualifications that, according to the proposed rules, will include a showing that the low-income participation is achieved and that 50 percent of the nameplate capacity of the project is subscribed. Additional final certification requirements may be added by order in the implementation manual development process. Final certification is intended to provide project managers and participants with rights and obligations as projects are incorporated into Oregon's integrated utility regulatory system.

Geographic and Customer Subscription Limits

To better understand Staff's recommended rules regarding geographic limitations on projects and customer restrictions, context on existing state and federal policy is important. Staff believes a summary of the following topics will instruct stakeholders on Staff's positions that have elicited the majority of stakeholder feedback so far:

1. Direct Access
2. Public Utilities Regulatory Policies Act (PURPA)
3. Retail net metering

Direct Access

Senate Bill (SB) 1149, passed in 1999, requires PGE and PacifiCorp to establish direct access programs in their respective service territories. Through direct access, large non-residential customers have the ability to purchase electricity from a provider other than their current utility. The supply mix and environmental impact of the energy provided by the electricity service supplier (ESS), whom the customer contracts with to provide alternative energy, is determined by the customer's agreement with the ESS. A critical aspect of a customer's decision to "leave" the system and enter into a contract with an ESS is the impacts of the customer's transition to an alternative energy supplier, which manifests in the form of transition charges or credits that must be paid to PGE or PacifiCorp. A transition credit or charge is 100 percent of the net value of the Oregon share of all economic utility investments and all uneconomic utility investments of the electric company.

The non-residential customer's decision to procure energy from an entity other than the electric company impacts the cost-of-service to the remaining customers of the electric company, whose rates include the resources (such as generation, transmission, and distribution) that were built to serve all customers, including those that procuring energy from an outside entity. If the utility's extensive and long-term planning included a large customer's respective demand for power and the requisite resources to supply that power, those very resources may not be used in the planned manner if the customer leaves the system, resulting in an underutilized or potentially stranded asset that remaining customers must bear the cost and risk of continued operation.

Direct access also provides large customers with the opportunity to choose a supplier that will meet specific customer-driven resource development desires. Specifically, direct access providers have the ability to designate, build, and build retail energy contracts around new sources of energy, including renewable energy. Direct access provides the opportunity for large customers to participate in new solar developments of any size, in any location, under any contract term that the customer and the ESS can mutually agree too, provided that the Commission-approved transition charges are paid.

PURPA

PURPA, enacted by Congress in 1978, requires utilities to purchase electricity from "qualifying facilities" (QFs). In Oregon, PURPA has materially changed the role of renewable energy like solar photovoltaics (PV) for the investor owned utilities (IOU) and has shifted the percentage of renewables that comprise IOU's resource portfolio mix. Recent trends in utility resource planning in Oregon including thermal retirements, the continued fall in capital costs of solar PV, and sustained QF contracts executions suggest that solar PV QFs will play a significant role in renewable deployment in Oregon.

Net Metering

Customers in IOU territories have the opportunity to install solar PV systems on their property, allowing them to generate and consume their own power and offset power provided by the customer's utility. Fundamental to Oregon's net metering construct is the "retail" nature of the customer's arrangement with the utility. A non-retail transaction would invoke federal preemption because the customer would be selling power to the utility. In traditional net metering, the "netting" of power is a function of the facility directly interconnecting with the customer's meter, enabling it to truly offset the power consumed by a customer.

These three industry programs inform Staff's positions on the project location and customer restrictions described below.

Project Location

The following parts of the draft rules result in a potential participant being limited to projects in their respective contiguous service territory:

1. "Eligible customer" means a retail customer receiving electricity supply service from an electric company **in the same contiguous service territory where the project is located.**
2. To be eligible to participate in the community solar program as a subscriber or owner of a project, an entity must:
    a. Be a retail electricity customer of an electric company and take retail electricity service from that electric company **in the same contiguous service territory where the project for which a subscription or ownership interest is sought is located.**

Stakeholders have indicated the "contiguous" language would limit the availability of community solar project development options for some customers, particularly PacifiCorp customers. Stakeholders argue that those customers in so-called "load pockets" would be impacted the most. Based on stakeholder comments and further Staff analysis, Staff recommends the Commission eliminate "contiguous" from the aforementioned aspects of the proposed draft rules. Doing so would result in the rules restricting participation to a project located in a participant's respective utility's service territory.

Staff has reviewed pertinent national and state law and policy, contemplated numerous policy formulations, discussed location attributes with stakeholders and consulted other states' location requirements for their respective community solar programs and discussed. Staff does not take the decision to apply a geographic restriction lightly. Below are the main reasons Staff relies on to justify geographic restriction:

1. Net Metering Construct

   Staff has used a virtual net-metering construct for the Community Solar Program for a few reasons. First, SB 1547 makes discernable allowances for a program that is based on net metering (i.e., subscription and ownership shares limited to annual average usage). Second, a net-metering construct allows the Commission to establish the value for Project generation, something that the Commission would be preempted from doing if the Project participants simply sold the output to utilities. If participants sold power to the utility, which in turn would resell that power, than the participant transaction would likely be considered a wholesale transaction, which would be impermissible. Netting avoids the optics of a sale. Finally, Staff strongly believes that a virtual net metering program is the best use of the program considering the status of solar development in Oregon.

   The "void" that a community solar program can fill is narrow when one evaluates the rest of the solar development landscape (traditional resource planning, PURPA, renewable portfolio standard, and traditional net metering). Staff has designed the community solar program to provide customers the opportunity to participate in solar net metering who currently cannot do so due to various circumstances, such as being a renter, limited financial resources, or unsuitable roof. The program will exist primarily to provide an option to customers who have no other option to access solar PV.

   As described earlier, traditional net metering occurs when power generated flows through the same meter that measures consumption of the participating customer, hence the very real and measurable "netting" aspect. It is not practical to require physical netting in the Community Solar Program. However, Staff believes it is appropriate to require that the program participants generate and consume energy within the utility's system. A project that is not meaningfully proximal to a participant begins to resemble resources that exist elsewhere on the utility resource landscape. A community solar program that steps outside its carefully crafted boundaries and begins to cannibalize other utility resource avenues is one that that no longer can reasonably be attributed to solely fulfilling a customer's desire to contribute to a resource whose purpose is to solely offset their own consumption. If the goal has, is and will continue to be netting one's own consumption, Staff believes the locational aspect of net metering must be acknowledged and incorporated.

2. Resource value of solar (RVOS) elements

SB 1547 specifies that participants of community solar projects should be credited for generation at a rate that reflects the RVOS and directs the Commission to determine this value. The value streams, or elements, that comprise the RVOS in the Commission's straw proposal include elements that are intrinsically locational in nature, i.e., transmission and distribution capacity; line losses; and security, reliability, and reserves. These elements are benefits to the utility's system in which the project is ultimately delivering power, and for those specific elements mentioned above, benefit the distribution and/or transmission system of the utility in which the project is located. The benefits flow only to those customers of the specific utility as those same customers bear the proportional cost of purchasing the power from the project.

Staff believes that a project built outside of a utility's service territory will not achieve the full potential of these values; a project that is located distant from the load in which it ultimately is intended to serve and requires wheeling of power over third-party transmission likely will not have optimal values for any of the elements mentioned above. Under those circumstances, the project's applicable RVOS elements, such as energy and capacity, look more like a centralized, large generating asset. Not only does a project that is unable to utilize the full range of elements proposed in the RVOS methodology not comport with the legislature's intent in SB 1547, but it also fails to properly fit into the future utility model where distributed energy resources play a key role in meeting the demands of the system, a model that Staff and stakeholders are more seriously pursuing.

3. PURPA Optics

When evaluating the explanation under the previous section "Net Metering Construct," additional consideration must be given to a current option available to solar developers, which is PURPA. QF developers often minimize costs of projects in order to optimize revenues based on the avoided costs approved by the Commission. Efforts to accomplish optimal revenues include areas with maximum insolation, siting projects on affordable land and sizing projects as large as possible. Solar QF projects that are characterized by these traits often are located on the eastern part of the state. If allowed, Community Solar project developers would no doubt try to develop projects with similar project characteristics. But then, the Community Solar Program would result in projects like those already being built in Oregon. Staff believes this is inconsistent with the intent SB 1547, the utility resource landscape described above and Staff's vision for the community solar program.

This program is much more consumer-focused than PURPA and is intended to serve communities rather than solar developers. A community solar program should not duplicate a federal wholesale program designed to encourage solar developers. Rather, it should be focused on the needs and desires of retail customers.

4. Concerns of project development

Staff remains concerned about the likely path of community solar project development in the state if meaningful geographic restrictions are not implemented in the rules. It is fairly certain that most projects will seek to maximize revenue, which can be aided by building in the eastern part of the state for the reasons described in the previous section.

In addition, projects will likely be concentrated in discrete areas east of the Cascades that provide adequate transmission due to some, if not, most of the projects serving participants in load areas west of the Cascades. In other words, it's possible that, despite the vastness of the eastern part of Oregon, many projects will aggregate to the extent grante by existing statute, related rules and the proposed community solar rules. This outcome seems far from any sort of interpretation of what a community solar project would be doing to serve the needs of a community so far away from the resource.

5. Community Perspective

Recognizing the difficulty in any effort to define "community" Staff has refrained from doing so throughout the AR 603 process. However, Staff does feel comfortable in recognizing what clearly is **not** community, which manifests for Staff in parameters of a community solar program that lie far outside any reasonable interpretation of what "community" is. The primary parameter is distance. Clearly, some modicum of distance of generation from consumption is acceptable in a community solar program because the program is aimed at addressing the lack of physical access for customers in the current net metering model. To what extent that distance is permissible though is entirely subjective largely because "community" is such a flexible term. A customer of PGE who lives in northwest Portland likely has limited if any communal connections to a project located nearly 400 miles away in southeastern Oregon.

> Though many distinguishable, defining threads together form the fabric of community, Staff believes that the themes identified above, namely the net metering construct and RVOS, must be incorporated into any assessment of acceptable distance because the costs, benefits and risks derive from the perspective of each participating utility. Because of these qualities, Staff believes that a fair and reasonable interpretation of community can extend to the service territory of a participant.

Customer Restrictions

Staff has spent considerable time assessing the intersection of program purpose, customer access, development trajectories and consumer protection in order to determine the necessary parameters to ensure a well-integrated and successful program that does not cause harm to customers or a utility's system performance. No optimal solution exists and trade-offs must be made. The net metering principles discussed above also heavily inform Staff's opinion on customer restrictions on a project level basis. Whereas Staff contemplated the locational aspect central to a net metering program when evaluating geographic restrictions, Staff considers the type of customers allowed to participate in net metering and what limits were placed on participation as it pursues community solar program design.

All customers are allowed to participate in net metering except direct access customers. Residential customers systems are capped at 25 kW and nonresidential customers have a 2 MW cap. Those caps as well as a discretionary program cap for each utility are necessary to ensure that the net metering program has limits that prevent defection from the cost-of-service in ways that would harm customers who remain with the utility.

These caps were recently updated in 2007, a time when costs for distributed solar were high enough to be prohibitive for most customers. With the precipitous fall of the cost of installing solar, which will continue to some degree, and the likelihood of rising rates for customers as utilities navigate changing markets and regulations, the need for limits on size of participation becomes even more paramount. This need is further enhanced by the desire of customers, businesses and public entities to shift their load to renewable energy sources as well as the growing interest in energy independence and customer choice.

Staff sympathizes with these desires and over time regulators and stakeholders may need to rethink larger questions of regulatory approaches. In the meantime however, Staff must prioritize policies that safeguard the regulated system when considering a voluntary program that will add physical load to a utility's system and the potential for cost shifting. The potential for customers, particularly commercial and large, to shift their load to significant quantities of new solar generation through the community solar program is high. Proportional to that new generation is the potential for embedded costs of the system to fall to customers who cannot or choose not participate in the program. Staff believes the maximum participation limits provided by the original net metering program are appropriate for the community solar program's initial implementation.

The initial rules provide for limits of one project per every customer, including affiliates of customers, with 40 percent of any one project limited to a single, discrete customer. Based on stakeholder input and the precedent of the net metering rules, Staff recommends the Commission adopt rules that allow for any one customer and its respective affiliates the opportunity to subscribe to a limited number of projects that result in a total capacity amount of no more than two megawatts, the same cap as the current net metering program.

Residential and small commercial customers should not be impaired by these updated subscription limitations; these customers' average annual loads fall far below the energy output of a two megawatt allocation of a solar PV system. Commercial and large customers may not have their entire load covered by a full two megawatt subscription. Additionally, Staff does not feel it can discriminate against private organizations by making exceptions for public entities like municipalities. The underlying concern of load migration and subsequent cost shift remains the same. Staff cannot allow the program to enable significant load transition through these customers not only because of the concerns described above, but also because nonresidential customers, including municipalities, have the opportunity to procure part or all of their respective energy requirements through their utility's direct access program. The requirements behind direct access ensure that such large load transitions have minimal impacts on remaining customers. Staff cannot ignore the structure and intent of direct access when designing the community solar program.

<u>Interim rate</u>

As noted above, SB 1547 specifies program participants should be credited for their share of project generation at the RVOS and that the Commission should determine RVOS. It also provides that the Commission may adopt a rate other than RVOS for good cause. The Commission is currently considering methodologies to determine RVOS in Docket No. UM 1716. Because it is not clear when Docket No. UM 1716 will conclude, stakeholders ask the Commission to establish an interim rate for use in the Community Solar Program. Staff believes that such a proposal is premature. As noted above, Staff envisions a staged process to implement the Community Solar Program. It may be that the Commission will conclude the UM 1716 docket prior to the first request for pre-certification of a Community Solar project. However, if it becomes apparent that an interim rate is necessary to allow projects to begin selling subscriptions and ownership shares, the Commission can open an investigation to establish such a rate.

Program Tier

The proposed draft rules increased the initial program capacity from one percent to 2.5 percent of a utility's 2016 peak load, which results in approximately 160 MW of available capacity. Staff chose to increase this amount to provide financial stability to the program administrator. Due to the higher costs that will arise in the initial years of the program, including those that are unknown at this point in time and are likely to occur in order to accommodate an entirely new and complex program, Staff concluded that spreading those costs over more projects would reduce the risk of cost shift that could occur if the program were smaller and more funds were needed in the program's future.

Because increasing the program size to 160 MW exceeds Staff's initial conception of this program, which totaled about 65 MW, additional analysis and consideration will be needed if and when the Commission contemplates increasing the capacity tier.

Low-Income

Several parties have requested clarification of language in proposed rule 869-088-0170. Staff originally proposed that 10% of the subscriptions for every community solar project would be allocated to the Low Income Manager to enroll eligible participants. By choosing the project level approach, there was assumed to be high certainty of meeting the 10 percent obligation for the program. Several parties preferred that the 10 percent be identified at the program level, versus the project level. In this new proposed rule Staff created a compromise of both. The rules now reserve five percent of each project's total capacity for low-income customers, and five percent for projects that are in part or fully dedicated to serve low income customers, or housing service entities serving low income customers. Staff addressed the risk in having 5 percent at the program level by inserting an additional rule such that the Program capacity tier of 2.5 percent cannot be increased unless the Low Income allowance has been met.

Parties are concerned that the five percent projects and five percent program requirements may overlap. Instead of cumulatively adding up to an overall ten percent low income requirement for the program, they could be read to allow double-counting, resulting in total program capacity devoted to low-income customers that is less than 10 percent. Staff intends these totals to be cumulative and that double counting will not be permitted under Staff's interpretation of the rules.

This section of rules addresses the methodology by which the 10 percent allowance could be determined yet does not address the affordability of subscriptions for low-income participants. Even though subscriptions would be "reserved" for low income, the economics have not been clearly assigned.

Stakeholders have expressed concern about the financial barriers low-income customers will face when considering participation. Though Staff believes a full subsidy of subscription costs for low-income participation is not appropriate, Staff encourages the Commission to consider some sort of intra-program fee that all participants pay in order to bring down the cost of individual low-income customer participation. The details in setting a fee that is consistently applied across all subscriptions to result in a pool of funds that is then used to reduce the cost of participating for low income could be designed through Commission order yet broadly defined in the rules. In addition, the subscription allocation methodology could be reworked such that the collected pool of funds would lead to certain prioritization of low-income subscriptions in subsequent projects. The result would be a departure from the five percent project and five percent program proposal such that each project may have 0-100% low income subscriptions yet overall the program achieve 10 percent with all participants, contributing towards making community solar affordable for low income.

Bill Credit Rate

Parties have requested clarification of the term of the Bill Credit rate, discussed in proposed rule 860-088-0090(4). It is Staff's intention for the Bill Credit rate to be set utilizing the RVOS at the time of pre-certification, and that the RVOS as identified at the time of pre-certification would not change, even if a new customer subscribes to the project at a later date. The RVOS rate established for the project at the time of precertification would be used to calculate Bill Credits for the life of the project.

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