ITEM NO. 2

PUBLIC UTILITY COMMISSION OF OREGON
STAFF REPORT
PUBLIC MEETING DATE: April 24, 2018

REGULAR X **CONSENT** ____ **EFFECTIVE DATE** **N/A**

DATE: **April 10, 2018**

TO: Public Utility Commission

FROM: Caroline Moore CM

THROUGH: Jason Eisdorfer and JP Batmale JPB for JE JPB

SUBJECT: OREGON PUBLIC UTILITY STAFF: (Docket No. UM 1930) Interim Alternative Bill Credit Rate Proposals for Community Solar.

STAFF RECOMMENDATION:

Consider adoption of one of three interim alternative bill credit rate proposals.

DISCUSSION:

Issue

Whether the Commission should consider adoption of one of Staff's proposed interim alternative bill credit rates:

- Simple Retail Rate
- Adjusted Retail Rate
- Adjusted Resource Value of Solar (RVOS)

Applicable Law

Section 22 of Senate Bill (SB) 1547, effective March 8, 2016, directs the Public Utility Commission of Oregon (Commission) to establish a program that provides electric customers with the opportunity to share the costs and benefits of solar generation (hereinafter referred to as "Community Solar Program", "Program" or "CSP). Community Solar Program participants bear a portion of the cost to construct and operate a solar facility and receive a bill credit from their electric company for their portion of the solar facility's output.

SB 1547, sec. 22(6)(a) specifies that electric companies shall credit CSP participants for their proportional shares of CSP project generation "in a manner that reflects the resource value of solar" and directs the Commission to determine the resource value of solar energy (RVOS). However, sec. 22(6)(b) provides that the Commission may adopt a rate for an electric company to use in crediting a participants electric bill that does not reflect the resource value of solar "if the Commission has good cause to adopt the different rate." The legislation also provides the Commission authority to suspend the program for good cause.[1]

On June 29, 2017, the Commission adopted formal rules for Oregon's Community Solar Program through Order No. 17-232. That order adopted Division 88 of Chapter 860 of the Administrative Rules, which includes the following directive to establish the bill credit rate based on the RVOS:

> *Unless otherwise determined by Commission order, the bill credit rate for a project will be based on the resource value of solar applicable to that project at the time of pre-certification and will apply for a term no less than the term of any power purchase agreement entered into pursuant to OAR 860-088-0140(l)(a).*[2]

In Order No. 18-088, the Commission determined there is good cause to develop an interim alternative bill credit rate, due to issues of timing and value associated with the application of RVOS as the initial CSP bill credit rate.

<u>Analysis</u>

Background

At the January 30, 2018 Public Meeting, the Commission determined that it is necessary to accelerate consideration of an alternative CSP bill credit rate, and requested a Commission workshop to discuss the possibility of an alternative bill credit rate. The Commission additionally directed Staff to report on bill credit rate issues in preparation for the workshop. Staff reported that considerations for establishing an alternative CSP bill credit rate are based on whether the timing and/or value of the RVOS will support an effective program launch. In addition, Staff found that a wide range of approaches to establishing a value for solar generation exist and can be applied to meet different program objectives, such as opportunity, fairness, participation, project development, and project diversity.

Stakeholders responded to Staff's report with written and oral comments at the March 5, 2018 workshop. Stakeholder comments coalesced around a few central points:

- Utility stakeholders noted concern with consideration of an alternative rate that does not reflect RVOS, particularly before the RVOS is finalized. In addition, utility stakeholders urged for minimal cost shift if an interim alternative rate is established.
- Stakeholders from the solar industry, environmental groups, consumer protection groups, local governments and a range of additional interests advised that an alternative bill credit rate is required for a successful program launch. These

[1] Senate Bill 1547, Section 22 (2)(c).
[2] Oregon Administrative Rules 860-088-0170 (1)(a).

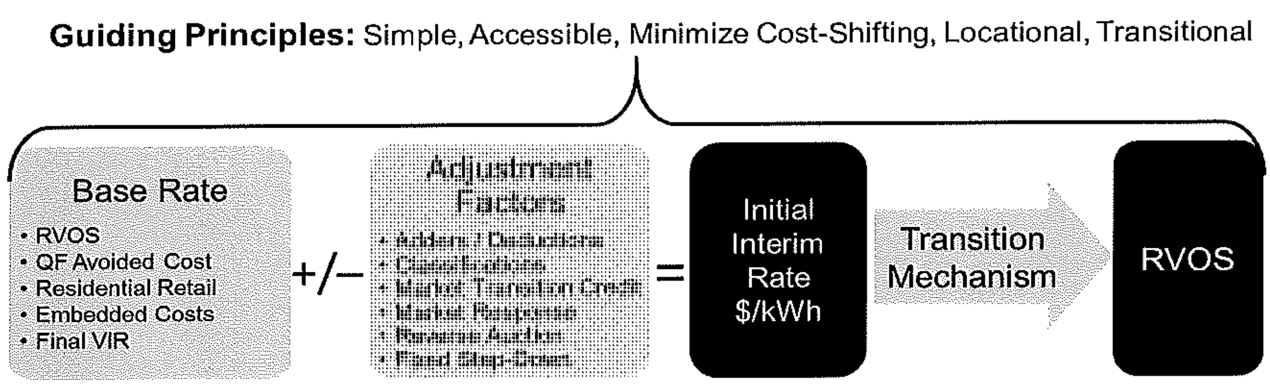
stakeholders expressed concern that waiting for RVOS will cause untenable delays and suggested that third-party project development will not occur at rates reflecting the initial utility RVOS estimates provided in Docket Nos. UM 1910-12. Several stakeholders additionally suggested that project development is not possible without a rate high enough to provide participant bill savings.

- Several stakeholders suggested that the residential retail rate provides a quick and familiar solution, but could not confirm whether the value would be sufficient to support project development in Oregon.
- The Energy Trust of Oregon stated that establishment of an alternative rate may be iterative and require a certain level of experimentation.

Following the workshop, the Commission issued Order No.18-088, finding good cause to consider the adoption of an interim alternative CSP bill credit rate (interim alternative rate) based on issues of timing and value.[3] The order directs Staff to provide the Commission with no less than three interim alternative rate proposals through a report filed no later than April 10, 2018.[4]

In this report submitted in compliance with Order No. 18-088, Staff analyzes a range of rate options and presents three interim alternative rate proposals for Commission consideration.

Evaluation Framework
Order No. 18-088 outlines several objectives and considerations for developing an interim alternative rate. Staff identified three rate components and evaluated each component's alignment with the Commission's guidance. No available rate aligns seamlessly with all principles; therefore, Staff proposes three rates designed to strike an optimal balance across the Commission's objectives and considerations.



The figure above illustrates Staff's process to develop three proposed interim alternative rates. The process begins with a Base Rate that is modified with Adjustment Factors to establish an Initial Interim Rate. A Transition Mechanism is applied to each of the three

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[3] Order No. 18-088, p.2.
[4] *Ibid*, p.4.

Initial Interim Rates, allowing the rate to revert to the RVOS in the long run. Every component is informed by Staff's Guiding Principles.

Guiding Principles
Staff's framework for evaluating rate options is based on five Guiding Principles. A description of each principle and how Staff applied it in its evaluation are provided below.

1. **Simple:** The Commission cites timing as grounds to consider an interim alternative rate, and finds that, "[i]n order to facilitate a potential Community Solar program launch in 2018, stakeholders have consistently expressed to us it is important to have bill credit rates established and known as early in the year as possible; ideally, the rates would be established no later than the end of April 2018."[5]

   In addition, the Commission states that the interim alternative rate, "presents an imperfect temporary solution, and it may be rough and less sophisticated than the permanent bill credit rate methodology due to the fact that we have identified delay as an outcome we wish to avoid."[6]

   Finally, the Commission acknowledges that, "[t]hough Staff should not feel bound by the precedent of other jurisdictions in the development of its options, Staff may wish highlight or base proposals on the rates set by other states."[7]

   To assess simplicity, Staff evaluated how readily each rate would be available. To the extent that it promotes simplicity, Staff also considered whether other jurisdictions have adopted that rate for similar programs.

2. **Accessible:** The Commission also cites the values presented in utilities' initial RVOS filings in Docket Nos. UM 1910-12 as grounds to consider an interim alternative rate. The Commission finds, "that our responsibility is to strive to stand up a functioning Community Solar program, which results in active project development and the availability of subscriptions for customers."[8]

   To evaluate accessibility, Staff considered the likelihood that potential rates will result in active project development. Order No.18-088 does not discuss the likelihood that a rate will result in the development of diverse project types. Therefore, project diversity is not considered in Staff's evaluation framework. This report does note the expected impact of certain rate components on project diversity when relevant.

[5] *Ibid*, p. 2.
[6] *Ibid*, p.5.
[7] *Ibid*, p.4.
[8] *Ibid*.

3. **Minimize cost-shifting:** The Commission qualifies the need to stand up a successful program with the need to minimize cost shifting, stating that accessibility, "should be achieved at the lowest cost possible to non-participants in order that cost shifting is minimized."[9]

   Staff evaluated whether potential rates were designed to provide the lowest cost possible in order to minimize cost-shifting.

4. **Locational:** The Commission advises Staff to "strive to take into account that the rate may be scaled to provide higher levels of financial support to projects at the distribution level, and lower levels to projects farther from load that provide fewer system benefits."

   Staff evaluated considers whether rate options account for proximity to load or interconnection to a distribution feeder.

5. **Transitional:** The Commission intends for the interim alternative rate to be temporary such that the program transitions to an RVOS-based rate for the long term.[10]

   Staff evaluated whether rates included a mechanism to transition to RVOS.

Base Rates
The Base Rate is the foundation or starting point for determining the interim alternative rate. Staff identified five Base Rates, based on solar valuation models used in other Oregon solar programs and by other states' community solar programs. The table below summarizes Staff's assessment of each Base Rate using the evaluation framework.

[9] *Ibid*, p.4.
[10] *Ibid*, p.3.

Base rate	**Simple** *Is it readily available and/or used elsewhere?*	**Accessible** *Is it likely to result in active project development?*[11]	**Minimizes Cost-Shifting** *Is it designed to provide the lowest cost possible?*	**Locational** *Does it recognize the difference in project types?*	**Transitional** *Does it transition to RVOS?*
Initial RVOS *A single rate per utility based on values provided in Phase 2 of UM 1716*	Y	Y/N	Y	N	Y/N
QF Avoided Cost *Current real levelized non-renewable standard QF avoided cost rate, set per utility*	Y	Y/N	Y	N	N
Residential Retail Rate *Standard volumetric residential retail rate, set per utility*	Y	Y/N	N	N	N
Embedded cost *Estimated break-even point for participants based on a generic project LCOE, set statewide*	N	Y/N	N[12]	N	N
Final VIR *Lowest VIR for small/medium projects in the last tranche before the program ended, ~$0.16/kWh, set statewide*	Y	Y/N	N	N	N

Y = Supported by the base rate alone
N = Not supported by the base rate alone
Y/N = Possibly supported by the base rate alone or unknown

[11] Staff does not have sufficient data to predict how successful any of the Base Rates will be in spurring project development in Oregon.
[12] Analysis provided by Energy Trust of Oregon suggests that the embedded cost may range from an estimated $0.06/kWh to $0.29/kWh. The average cost of different system types, based on project size, location and use of tracking, range from $0.09/kWh to $0.22/kWh. Staff does not find that the majority of embedded cost values modeled minimize cost-shift. See Attachment A for a summary of Energy Trust's cost analysis.

Staff finds that no Base Rate satisfies all of the principles; however, two rates appear to provide the most balance.

- **Residential Retail Rate:** A very simple option, utilized in multiple jurisdictions,[13] which represents a midpoint in value between accessibility and minimizing cost-shifting relative to the other Base Rates considered.

- **Initial RVOS**: The Base Rate with the greatest opportunity to minimize cost-shifting that is best positioned to transition to RVOS. While a final RVOS is not available, initial rate options are readily available through the UM 1716 and UM 1910-12 records. A value of solar-based rate is also used in other jurisdictions.[14]

Adjustment Factors
Adjustment Factors modify the value and application of the Base Rate to better align with the Guiding Principles. Together, the Base Rate and Adjustment Factors will comprise the Initial Interim Rate. A single modifier can be applied to a Base Rate or modifiers can be combined to better balance associated trade-offs. Staff identified and evaluated several Adjustment Factors, based on its survey of other Oregon solar programs and community solar models across the country.[15]

- **Adders/Deductions:** Projects receive cumulative adders and/or deductions to the Base Rate based on characteristics that align with or diverge from the Guiding Principles. Examples include whether or not:
    - The project is located on the distribution feeder (Locational).
    - All participants are located in same county as the project (Locational).
    - The project exceeds the minimum residential and small commercial participation level, which increases participation costs (Accessible).
    - The project exceeds the minimum low-income participation requirements, which increases participation costs (Accessible).
    - The project is owned by a non-profit, which increases project costs by removing access to the Federal Investment Tax Credit (Accessible).

- **Market Transition Credit (MTC):** The MTC is a universal adder intended to promote accessibility for all projects. A fixed step-down in the adder responds to the market as it stabilizes. In New York, the MTC is a utility-specific adder based on the difference between the Base Rate and the residential retail rate. Other methods for establishing the MTC could include:

[13] For example, California, Colorado, Massachusetts, Minnesota, and Rhode Island have based their community solar bill credit rate on iterations of the retail rate. See Staff's February 26, 2018 report and comments filed by OSEIA-CCSA, pp. 13 - 16, for discussion of other jurisdictions.
[14] For example, New York and Minnesota have adopted community solar rates based on an iteration of the value of solar. See Staff's February 26, 2018 report and comments filed by OSEIA-CCSA, pp. 13 - 16, for discussion of other jurisdictions.
[15] See Staff's February 26, 2018 report for a survey of solar programs in Oregon and other states.

  - An adder based on the estimated incentive required for project development.
  - An adder that raises the Base Rate up to the maximum acceptable rate impact.
  - An adder that supports the unique economic proposition for low income customers.

- **Classifications:** Generic project characteristics determine how rates are assigned. Classification examples include:
  - Project size i.e., provide a simpler rate for less sophisticated projects or a higher rate for projects with lower economies of scale, to improve the economic proposition.
  - Geographic zone i.e., assign higher rates to projects with lower solar potential to improve the economic proposition.[16] Facilitating project development in lower solar potential areas has a secondary effect of limiting the total rate impact by reducing the total megawatt-hours ratepayers bear at the interim alternative rate.

- **Market Response:** Adjust the rate up or down based on whether applications exceed or fall short of a pre-determined tranche and timeframe.

- **Reverse Auction:** Project Managers bid for pre-certification capacity at a bill credit rate specified by the bidder. The Base Rate or an adjusted base rate can be used as a ceiling on bids. Classifications may be applied to help ensure project type and Project Manager diversity due to the increased level of sophistication required to bid.

- **Fixed step-down:** Adjust the rate down on a fixed schedule that is expected to align with the market development. Step-down examples include:
  - Adjust the rate down at pre-determined MW tranches.
  - Adjust the rate down when rate impact thresholds are reached.
  - Set a calendar schedule to adjust the rate down.[17]

The table below summarizes Staff's evaluation of each component. As with Base Rates, each Adjustment Factor has trade-offs. In the context of these trade-offs, Staff finds that many Adjustment Factors are appropriate to be considered in its proposed interim alternative rates.

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[16] This is how Oregon's Solar Incentive Program assigned volumetric incentive rates (VIR) to small and medium projects. See Staff's February 26, 2018 report for a description of the VIR.
[17] Washington State's solar incentives incrementally step down per calendar year. See Staff's February 26, 2018 report for a description of the Washington solar incentives.

Adjustment Factors	PROS	CONS
Adders/ Deductions	• Adders can help spur project development (Accessible) • Deductions can control cost-shift (Minimize Cost-shift) • Tailoring adders to only apply to specific projects can help control cost-shift (Minimize Cost-shift) • Can be responsive to different project types (Locational)	• Will require up front analysis to select adders and establish values (Simple) • Deductions can deter project development (Accessible) • Establishing a rate for each project may increase administrative costs (Minimize Cost-shift) • Adders are not designed to provide the lowest rate possible (Minimize Cost-shift)
Market Transition Credit	• Designed to spur project development (Accessible) • Increases certainty for Project Managers (Accessible) • Step-downs help control cost-shift (Minimize Cost-shift)	• Will require up front analysis to establish (Simple) • Will increase cost-shift over the Base Rate (Minimize Cost-shift) • Not responsive to different project types without other Adjustment Factors (Locational)
Classifications	• Can be simpler than project-specific adders/deductions (Simple) • Tailoring rates to specific project-types can help control cost-shift (Minimize Cost-shift) • Responsive to different project types (Locational)	• Will require up front analysis to establish (Simple) • Less control over individual projects' cost shift than adders/deductions (Minimize Cost-shift) • Less responsive to different project types than adders/deductions (Locational)
Market Response	• Does not require initial analysis to establish the value (Simple) • Focused on finding the lowest rate that spurs project development (Accessible, Minimize Cost-shift)	• Will require up front analysis to establish adjustment tranches or timeframe (Simple) • Less certainty for potential Project Managers (Accessible) • May increase administrative costs (Minimize Cost-shift) • Not responsive to different project types without other Adjustment Factors (Locational)
Reverse Auction	• Does not require initial analysis to establish value (Simple) • Focused on finding the lowest rate that spurs project development (Accessible, Minimize Cost-shift)	• Less certainty for potential Project Managers (Accessible) • Likely to increase administrative costs (Minimize Cost-shift) • May result in additional cost shifting if a cap on bid price is not established. • Not responsive to different project types (Locational)
Fixed Step-down	• Can increase certainty for Project Managers (Accessible) • Step-downs help control cost shift (Minimize Cost-shift)	• Pre-set step-downs may not correspond to market needs when in place e.g., step-downs based on time (Accessible) • Not responsive to different project types (Locational)

Transition Mechanism

A final modifier is required to align the Initial Interim Rate with the need to ultimately transition to RVOS. The Transition Mechanism controls the gross level of cost-shifting, while allowing the program to launch quickly and reach stability under the Initial Interim Rate. Staff considered several Transition Mechanisms based on the Guiding Principles:

- **Capacity Tier:** Begin using RVOS when the Capacity Tier set forth in OAR 860-088-0080 is reached to promote accessibility (per utility).
- **Initial Capacity Threshold:** Transition to RVOS when the market has developed to a pre-determined MW threshold prior the Capacity Tier, to balance accessibility and cost-shifting (per utility).
- **Availability of RVOS:** Transition after the Commission adopts a final RVOS to minimize cost-shifting.
- **Sunset**: Select a date by which the market should be stable enough to transition to promote simplicity.
- **Rate Impact Cap:** Begin using RVOS when the average annual rate impact reaches a maximum cost-shifting threshold to minimize cost-shifting.

Staff finds that an Initial Capacity Threshold provides the most balanced Transition Mechanism. The MW cap allows the program to demonstrate a level of stability before transitioning to RVOS, while controlling the amount of cost-shifting created within the Capacity Tier.

Establishing a Transition Mechanism may incentivize a "gold rush" prior to transition, meaning that Adjustment Factors, such as classification or adders/deductions, should be considered to help different project types access the Initial Interim Rate. In addition, the Transition Mechanism may trigger an evaluation of whether the program is ready to transition to RVOS, rather than an immediate transition to RVOS.

Interim Alternative Rate Proposals
Staff assembled three interim alternative rate proposals, which present different approaches to balancing Commission objectives.

1. **Simple Retail Rate:** Emphasizes simplicity by foregoing Adjustment Factors. The rate relies on the residential retail rate's value relative to the other Base Rates and the Transition Mechanism to balance accessibility and minimizing cost-shifting.
2. **Adjusted Retail Rate:** Builds upon the Simple Retail Rate, applying several Adjustment Factors to increase alignment with the Guiding Principles.
3. **Adjusted RVOS:** Focuses on correcting the issues of timing and value associated with the application of RVOS to the CSP. A readily available RVOS-based Base Rate helps correct issues of timing and Adjustment Factors help align that value with the Guiding Principles.

Staff notes that it is challenging to consider a CSP bill credit rate in isolation of the rate participants will pay to subscribe or own a project. Staff's analysis focuses on the best available information and the Guiding Principles.

Rate Proposal	Simple Retail Rate	Adjusted Retail Rate	Adjusted RVOS
Base Rate	Residential Retail	Residential Retail	Initial RVOS
Adders/ Deductions	--	• Small/medium projects: 5% deduction.[18] • Large projects: Deduction to the midpoint between residential retail and QF avoided cost.[19]	• MTC adder: $0.04[20] • Distribution feeder adder: $0.01[21]
Classifications	--	• Small/medium projects = ≤ 360 kW[22] • Large projects = > 360 kW	
Market Response	--	Small/medium projects only: • Open pre-certification for 5% of the Capacity Tier.[23] • Adjust rate down if pre-certification applications exceed initial tranche in first 12 months. • Adjust rate up if pre-certification applications fall short of initial tranche in first 12 months. • Continue in ≤5% Capacity Tier increments until transition to RVOS (based on remaining capacity).	Adjust MTC up if no third-party pre-certification applications are received in 12 months of initial launch and/or the MTC step-down.
Reverse Auction	--	Large projects only: • Open pre-certification for 15% of the Capacity Tier. • Bids are capped at the large project Adjusted Retail Rate. • Bids with the lowest bill credit rate are awarded capacity until the tranche is full. • Adjust cap up if tranche is not met within auction window. • Continue in ≤15% Capacity Tier increments until transition to RVOS (based on remaining capacity).[24]	
Fixed Step-Down	--	--	MTC steps down by 50% ($0.02/kWh) at 25% of total Capacity Tier (~40 MW)[25]
Transition Mechanism	At 50% of Capacity Tier, evaluate whether to transition to RVOS or continue with interim rate.	At 50% of Capacity Tier, evaluate whether to transition to RVOS or continue with interim rate.	At 50% of Capacity Tier, evaluate whether to transition to RVOS or continue with interim rate.

[18] Reflects the value of the start-up costs covered by all ratepayers and that the energy from these projects is not directly offsetting the participants' load as in net metering.
[19] Based on Staff's finding that large community solar projects are a hybrid of a residential distributed solar project and a QF solar farm. The real, levelized standard QF rate is used in this analysis.
[20] Access to the Federal Investment Tax Credit appears to create an approximate $0.04/kWh difference in the levelized cost of energy based on the modeling tools used by ETO. Staff used this value as a proxy for the level of incentivization a solar project requires.
[21] Based on PGE's initial UM 1912 testimony, which valued T&D at $0.008/kWh and line losses at $0.00148/kWh.
[22] OAR 860-088-0150 threshold to register in WREGIS, which signals developer sophistication.

	Simple Retail Rate		Adjusted Retail Rate			Adjusted RVOS [26]		
Estimated Bill Credit Rate ($/kWh)				*Sm/Med.*	*Large*		*Pre-step down*	*Post step down*
	PGE	$0.1103	PGE	$0.1048	≤$0.0761	PGE	$0.0899 - $0.0999	$0.0699 - $0.0799
	PAC	$0.1005	PAC	$0.0954	≤$0.0716	PAC	$0.0728 - $0.0828	$0.0528 - $0.0628
	IPC	$0.0880	IPC	$0.0836	≤$0.0707	IPC	$0.0416 - $0.0516	$0.0216 - $0.0316

Trade-offs

Order No. 18-088 directs Staff to weigh the pros and cons, costs and benefits, and trade-offs of proposed rates. The following table provides Staff's assessment of the trade-offs associated with each proposed interim alternative rate, including the ability to balance Commission guidance and the estimated incremental impact to ratepayers.

	Simple Retail Rate	Adjusted Retail Rate	Adjusted RVOS
PROS *How does the proposed rate better align the Base Rate with the guiding principles?*	• Most readily available, very simple. • Most likely to spur active project development relative to other proposed rates. • Transitions to RVOS. • Meets four of five Guiding Principles.	• Adjustment factors are based on simple analysis and readily available values. • Most likely to balance active project development while providing the lowest cost possible relative to other proposed rates. • Classifications are responsive to project size, which can reflect distribution-level benefits. • Transitions to RVOS. • Meets five out of five Guiding Principles.	• Adjustment factors are based on simple analysis and readily available values. • MTC increases likelihood of active project development and certainty. • RVOS and fixed step-down control cost shift. • Adders are responsive to distribution-level benefits. • Transitions to RVOS. • Meets five out of five Guiding Principles.
CONS *Which trade-offs are associated with the proposed rate?*	• Least control of cost-shift of proposed rates (only through Transition Mechanism). • Not responsive to distribution-level benefits.	• Requires establishment of deductions, classifications, reverse auction process, tranches, and a new rate if initial rate is too low or high. • Possibility of higher administrative costs. • Less certainty for Project Managers.	• Requires establishment of the MTC, the distribution adders, step-downs, and a new rate if the initial and/or step-down rate is too low or high. • Least likely to spur active project development relative to other proposed rates. • Possibility of higher administrative costs.
Est. Rate Impacts [27]	PGE $58,816,624 (0.12%) PAC $42,588,656 (0.13%) IPC $1,379,565 (4.33%)	PGE $38,325,680 (0.08%) PAC $30,945,807 (0.09%) IPC $930,421 (2.92%)	PGE $35,865,347 (0.08%) PAC $30,801,605 (0.09%) IPC ($470,089) (-1.47%)[28]

[23] Each 5% tranche allows ~12 - 186 PGE projects, 8 - 129 PAC projects, and ≤ 4 IPC projects (25–360 kW).
[24] Each 15% tranche allows ~4 - 38 PGE projects, 3 - 26 PAC projects, and 0 IPC projects (<360 kW).
[25] 25% of the Capacity Tier allows ~7 - 931 PGE projects, 5 - 646 PAC projects, and ≤ 22 IPC projects.
[26] The range represents the $0.01/kWh difference between a distribution and transmission project's rate.
[27] Staff's estimate assumes that the program is fully subscribed up to the Transition Mechanism (~80 MW) for 20 years (the minimum PPA term for CSP projects). Estimated rate impacts are in real 2018 dollars gross over 20 years. Percentages represent the gross rate impact as a percentage of revenue requirement from 2018 - 2037. Adjusted Retail Rate assumes that small/medium projects comprise 20 percent and large projects comprise 30 percent of the Capacity Tier, the initial rates are not adjusted up or down, and all large projects are awarded at the cap. The Adjusted RVOS assumes an average rate between the adder and non-adder rate.
[28] Idaho Power's initial RVOS ($0.00161/kWh) is lower than the Company's standard QF avoided cost rates, such that the adjusted RVOS provides a net benefit to ratepayers over 20 years.

The estimated rate impacts represent the incremental cost to ratepayers for purchasing the output from CSP projects at each of the Interim Initial Rates, over the cost to purchase the output at the real levelized standard QF avoided cost rate. The QF avoided cost rate is the best reflection of both the costs and the value of solar generation currently available i.e., QF avoided cost represents a break-even point, over which the rate will reflect the generation's costs in excess of the generation's value. Staff notes that RVOS would be a better reflection of the breakeven point if Commission adopted RVOS values were available.

<u>Conclusion</u>

Order No. 18-088 establishes good cause to develop an interim alternative bill credit rate for Oregon's Community Solar Program, directs Staff to propose a minimum of three interim alternative rates, and outlines several Commission objectives and considerations for developing an interim alternative rate proposal.

Staff identified three components of the interim alternative bill credit rate and evaluated options for each component based on the Commission's guidance. Staff did not find a rate concept that aligns seamlessly with all Guiding Principles, but proposes three approaches to balancing the Guiding Principles for program success.

Rate Proposal	**1. Simple Retail Rate**	**2. Adjusted Retail Rate**		**3. Adjusted RVOS**	
Base Rate	Residential Retail Rate	Residential Retail Rate		Initial RVOS	
Adders/ deductions		X		X	
Classifications		X			
Market response		X		X	
Reverse auction		X			
Fixed-step down				X	
Transition Mechanism	X	X		X	
Rate ($/kWh)		***Sm/Med.***	***Large***	***Pre-step down***	***Post step down***
PGE	$0.1103	$0.1048	≤$0.0761	$0.0899 - $0.0999	$0.0699 - $0.0799
PAC	$0.1005	$0.0954	≤$0.0716	$0.0728 - $0.0828	$0.0528 - $0.0628
IPC	$0.0880	$0.0836	≤$0.0707	$0.0416 - $0.0516	$0.0216 - $0.0316
Est. Rate Impacts					
PGE	$58,816,624 (0.12%)	$38,325,680 (0.08%)		$35,865,347 (0.08%)	
PAC	$42,588,656 (0.13%)	$30,945,807 (0.09%)		$30,801,605 (0.09%)	
IPC	$1,379,565 (4.33%)	$930,421 (2.92%)		($470,089) (-1.47%)[29]	

The three proposals represent Staff's best recommendation; however, the Commission can apply the various modifiers to any Base Rate to balance the Guiding Principles. If

[29] Idaho Power's initial RVOS ($0.00161/kWh) is lower than the Company's standard QF avoided cost rates, such that the adjusted RVOS provides a net benefit to ratepayers over 20 years.

the Commission elects to adopt a configuration that differs from Staff's proposals, Staff provides the following suggestions:

- Be iterative. Provide opportunities for adjustment and/or evaluation at or prior to reaching the transition to RVOS.
- Consider transition to RVOS prior to the Capacity Tier to balance cost-shifting and accessibility.
- Consider classifications to prevent less sophisticated projects from accessing interim alternative rates prior to step-down or transition to RVOS.

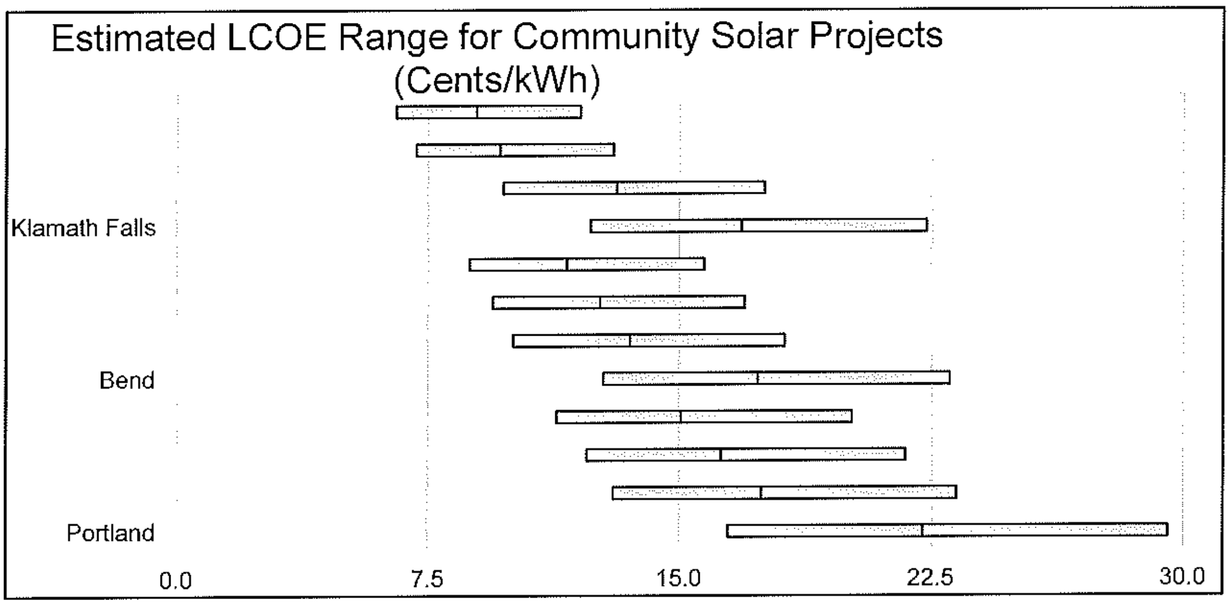
PROPOSED COMMISSION MOTION:

Consider adoption of one of three interim alternative bill credit rate proposals.

UM 1930
April 10, 2018

Attachment A
Embedded Cost Modeling

The estimated cost ranges below were generated by Energy Trust of Oregon using a range market assumptions. The variation in cost between locations is due to geographic differences in solar insolation, while the cost variation across system sizes reflects economies of scale achieved by larger projects. For a given project size and location, Energy Trust used a wide range of cost assumptions for key model inputs, including: equipment, labor, development, customer acquisition, ongoing customer management, financing and O&M. The resulting analysis is a high-level estimate of potential project costs which may or may not reflect actual community solar project costs



Location	System type	Size	Low ($/kWh)	Average ($/kWh)	High ($/kWh)
Portland	Fixed	Extra Small	$0.165	$0.223	$0.296
		Small	$0.131	$0.175	$0.233
		Medium	$0.123	$0.163	$0.218
		Large	$0.114	$0.151	$0.202
Bend	Fixed	Extra Small	$0.128	$0.174	$0.231
		Small	$0.101	$0.136	$0.182
		Medium	$0.095	$0.127	$0.170
		Large	$0.088	$0.117	$0.158
Klamath Falls	Fixed	Extra Small	$0.124	$0.169	$0.224
		Small	$0.098	$0.132	$0.176
	Tracking	Medium	$0.072	$0.097	$0.131
		Large	$0.066	$0.090	$0.121