BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UM 1452

In the Matter of PUBLIC UTLITY COMMISSION OF OREGON Investigation into Pilot Programs to Demonstrate the use and effectiveness of Volumetric Incentive Rates for Solar Photovoltaic Energy Systems.	ORDER

DISPOSITION: PILOT PROGRAM ESTABLISHED

I. INTRODUCTION

ORS 757.365 (2009), as amended by House Bill 3690 (2010), mandates the development of pilot programs for each electric company to demonstrate the use and effectiveness of volumetric incentive rates (VIRs) and payments for electricity delivered by solar photovoltaic energy (SPV) systems. ORS 757.370 creates a solar capacity standard under which the electric companies must acquire a share of 20 megawatts (MWs) of nameplate capacity from large SPV systems by the year 2020.

To implement these statutes, we opened two dockets. In this investigation, we decide policy issues related to the development and implementation of the pilot programs required under ORS 757.365. In a companion docket, AR 538, we adopt rules necessary to implement the pilot programs. In that rulemaking proceeding, we also address the solar capacity standard required under ORS 757.370.

The following parties intervened and participated in this proceeding: the Industrial Customers of Northwest Utilities (ICNU); Portland General Electric Company (PGE); the Citizens' Utility Board of Oregon (CUB); PacifiCorp, dba Pacific Power (Pacific Power); Idaho Power Company (Idaho Power); the Environmental Law Alliance Worldwide (ELAW); the Energy Trust of Oregon, Inc. (Energy Trust); Oregonians for Renewable Energy Policy (OREP); Solar Energy Solutions; Renewable Northwest Project (RNP); Southeast Uplift Neighborhood Coalition; Oregon and Southern Idaho District Council of Laborers; SunEdison LLC; Ecumenical Ministries of Oregon and Oregon Interfaith Power and Light (EMO and OIPL); Sustainable Solutions Unlimited, Multnomah County Commissioner Jeff Cogen; Oregon AFL-CIO; Daniel Weldon; Raymond Neff; and the Staff of the Public Utility Commission of Oregon (Staff).

Pursuant to the schedule adopted by the Administrative Law Judge (ALJ) in this proceeding, on December 4, 2009, Staff filed a straw proposal for a feed-in tariff to implement the pilot programs. The adopted schedule further provided for parties to file opening comments on Staff's straw proposal on December 18, 2009.

On December 17, 2009, Staff filed a motion to postpone "indefinitely" the filing of initial comments, to allow parties the opportunity to discuss a jurisdictional issue that had arisen regarding possible exclusive Federal Energy Regulatory Commission (FERC) jurisdiction over the sale of electrical energy from the subject SPV systems to the electric utilities pursuant to the pilot program. Staff's motion was granted by ALJ ruling dated December 18, 2009.

On December 21, 2009, Staff filed comments addressing the jurisdictional issue and proposing two alternate solutions for implementing the pilot programs within the bounds of this Commission's authority. Opening comments were filed by: Staff; EMO and OIPL; Energy Trust; PGE; Pacific Power and Idaho Power (jointly); CUB; ELAW; OREP, at al[1]; ICNU; and RNP and "Partners."[2] Prior to the filing of closing comments, a workshop was held with all Commissioners participating on January 20, 2010. After the workshop, the ALJ issued a ruling inviting parties to address in their closing comments questions framed by the Commissioners.

Closing comments were filed by: Staff; PGE; ICNU; ELAW; CUB, Pacific Power and Idaho Power (jointly), OREP, et al; Energy Trust; EMO-OIPL; and RNP and Partners.

On March 22, 2010, RNP and CUB filed a joint motion for an order that would allow the parties to file supplemental comments regarding recent solar installed-cost data and also direct the Staff to submit a revised rate table that incorporates changes in the installation costs. The motion was granted by ALJ ruling dated March 29, 2010.

Supplemental comments were received from RNP and CUB, filing jointly; RNP, CUB, and Oregon Solar Energy Industries Association (OSEIA); OREP, et al; ELAW, SolarWorld Industries America, the Oregon Solar Energy Industries Association, and IBEW Local 48; ICNU; Energy Trust; and Staff.

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[1] Joining OREP in its comments were: Albina Community Bank; Environment Oregon; Solar Energy Solutions, Inc.; National Solar, Inc.; Sustainable Solutions Unlimited, LLC; MoveOn Portland Council; ELAW; EMO and OIPL; Douglas A. Rich, Financial Consulting and Capital Sourcing; Columbia Riverkeeper; and intervenor Raymond Neff.

[2] RNP's "partners" are: CUB, the Oregon Solar Energy Industries Association, SolarCity, Tanner Creek Energy, EnXco, SunEdison, REC Solar, Obsidian Renewables, SunPower, Sunlight Solar, Sunergy Systems, Real Energy Solutions, & International Brotherhood of Electrical Workers Local 48 (IBEW Local 48).

II. BACKGROUND

In this proceeding, we must establish a pilot program for SPV systems for each electric company. The purpose of the pilot program is to demonstrate the use and effectiveness of volumetric incentive rates (VIR) and payments for electricity or for the non-energy attributes of electricity, or both, delivered from SPV systems that are permanently installed by retail electric consumers. This Commission is authorized to establish incentive rates for the pilot programs to enable the development of the most efficient SPV systems. These rates include all costs associated with the SPV system, and are distinct from the utility's avoided costs for, or the market rate of, the electricity generated. The cumulative nameplate capacity of the qualifying systems enrolled in the program may not exceed 25 megawatts (MW). The pilot program closes at the earlier of either 25 MW having been permanently installed, or on March 31, 2015.

Under ORS 757.365, we must design the pilot programs to attain the goal of 75 percent of the capacity to be allocated to "residential qualifying systems and small commercial qualifying systems." The legislature defined a "residential qualifying system" as a qualifying system with a nameplate capacity of 10 kilowatts (kW) or less, and a "small commercial qualifying system" as a qualifying system with a nameplate capacity greater than 10 kW and less than or equal to 100 kW. Qualifying systems may not have nameplate capacity greater than 500 kW.

III. THE FERC PREEMPTION ISSUE

Before we turn to the necessary components of the pilot program, we must address whether there are jurisdictional limitations to our ability to establish VIRs for SPV systems. The issue arises from the concern that the electricity transactions outlined in ORS 757.365 could be classified as wholesale sales in interstate commerce, which are subject to the exclusive jurisdiction of the FERC. As noted in an opinion from the Oregon Department of Justice, Staff's concern, echoed by many parties, is that a literal interpretation of the legislation might result in the Commission setting wholesale rates, a violation of federal law.[3] We note that this concern is not unique to Oregon; the issue has arisen in other states where the feed-in tariff model is in play.

The parties proposed various mechanisms designed to allow the Commission the ability to develop a pilot program that achieves the goals of ORS 757.365 while avoiding the FERC's exclusive jurisdiction over wholesale rates. The utilities, however, remain wary of the various mechanisms proposed. PGE strongly requests the Commission include a hold-harmless provision for the utilities under any proposal adopted. PGE asks the Commission to include a tariff provision that allows the electric company to recoup money from participants should the sales be deemed jurisdictional by the FERC and the payments found to be in excess of what is allowed by law. Similarly, Pacific Power and Idaho Power request the Commission include a hold harmless provision if it adopts a competitive bidding proposal discussed below.

[3] Staff's Comments at 1(Dec 21, 2009).

A. Proposed Solutions

1. Net Metering

Staff recommends the Commission frame pilot program transactions as "net metering" for projects of 100 kW or less. "Net metering" means measuring the difference between the electricity supplied by an electric company and the electricity generated by a consumer-generator and fed back to the electric utility over the applicable billing period.[4] Under this approach, consumers who installed SPV systems would be credited for electricity generated up to the amount of electricity consumed at the premises. The monthly credit could be set equal to the VIR established by the Commission. In essence, the consumer would receive a state-mandated subsidy for every kWh the consumer generates to off-set load. According to Staff, the legislature left the Commission with sufficient flexibility to frame the pilot program transactions as net metering, so long as the transactions do not result in a net sale to the utility over a reasonable period of time.

Staff acknowledges that the net metering proposal departs from the traditional feed-in-tariff mechanism by providing an incentive rate for participants for the energy they generate and use themselves, as opposed to the energy they transmit and send to the grid. Nonetheless, Staff claims there are sufficient similarities to ensure that a net metering approach will test the use and effectiveness of VIRs. For example, Staff notes that, similar to a traditional feed-in tariff, participants will know the VIR at the time of contracting with the electric company and will be entitled to that rate for all eligible energy produced for a lengthy period of time.

Staff also acknowledges the risk that consumers will consume more energy to increase the size of the VIR subsidy. Under a net metering approach, a consumer will be paid the VIR for all the energy generated, up to the amount of the energy used. A participant that generates energy in excess of the load may either donate that excess energy to charity, or sell it to the utility at market-based rates.[5] Where the consumer's use over a billing period would otherwise be less than the amount of the energy sold during that same period, the consumer may increase the energy use at the site to offset the excess generation and be paid accordingly.

Staff responds by questioning the scope of the potential problem. Staff notes that other parties have asserted that it is unlikely that most consumers will produce more energy from an SPV system than they consume. Regardless, Staff believes this problem can largely be addressed by ensuring that SPV systems are sized appropriately based on average consumption levels. Staff also notes that its proposal to limit net metering to small-scale and medium-scale systems is intended to minimize the risk of perverse incentives. Staff believes that consumers with large scale systems are the most likely to have an incentive to waste energy under a net metering option.

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[4] *See* ORS 757.300(1)(c).

[5] In order to sell the energy, the participant will have to obtain market rate authority from the FERC.

ICNU agrees that Staff's net metering approach is the best solution to the FERC preemption issue. CUB similarly supports the net metering proposal as a workable mechanism to test a feed-in tariff approach but avoiding federal jurisdiction issues. CUB notes the possible incentive for consumers to increase energy consumption under Staff's proposal, but does not believe the issue to be significant enough to forestall the use of net metering under the pilot project.

RNP similarly supports the use of a net metering approach, not only for small-scale and medium-scale projects, but also for a portion of large-scale projects. RNP contends that it is unlikely that a consumer will be able to produce more energy from a SPV system installed on a typical residential home than the consumer uses in a year. RNP agrees with Staff that the Commission could address this problem by limiting the size the system installed relative to the consumer's usage.

The Energy Trust favors a solution that is not subject to the FERC's authority and that would allow consumers to be paid a VIR for all energy generated by the SPV systems, regardless of electricity consumption. The Energy Trust notes that the net metering approach proposed by Staff could create an incentive for consumers to increase electricity consumption to benefit from VIR payments, but adds that this problem is not significant today because few SPV systems generate close to the site's energy consumption.

ELAW, OREP, and EMO-OIPL consider Staff's net metering approach to be cumbersome, loaded with perverse incentives, and unnecessary. ELAW and OREP criticize Staff's proposal because it is not a feed-in tariff contemplated by ORS 757.365. ELAW contends that HB 3690's relating clause referring to feed-in tariffs and amendments to ORS 757.365 make it clear that the Commission must adopt a true feed-in tariff for all SPV systems under the pilot project.

ELAW and OREP are also concerned about the perverse incentive under a net metering approach for consumers to consume as much electricity as they produce to maximize payments. ELAW suggests that adopting a proposal that includes the possibility of an incentive for consumers to consume *more* energy could subject this Commission and the State of Oregon to national ridicule. ELAW and OREP also refute attempts to minimize this potential problem. According to ELAW, ground-mounted installations and other well-designed systems could generate more electricity than is consumed on the premises. OREP adds that the artificial constraints imposed by net metering will limit the full development potential of SPV on a given site.

The utilities also oppose Staff's net metering proposal. At the outset, PGE is "uncertain" how Staff's proposal would be viewed by the FERC and the courts, and is wary of the risk this uncertainty would place on program participants and utilities in terms of their rate stability and recovery. Pacific Power and Idaho Power find Staff's net metering framework to be challenging, and state that the billing and accounting functions would be complex and difficult to administer. PGE adds that blocked energy charges and time of use pricing complicate the calculation of the net metering payment.

Pacific Power and Idaho Power also express concern about limitations paced on SPV systems to address the perverse incentive created by net metering. The utilities believe that size restrictions could negatively impact the adoption of SPV systems in new construction projects or in beneficial fuel switching applications. They propose, instead, that the Commission take a proactive role to promote the "right sizing" of systems. This would include requiring pilot program applicants to undergo an energy audit by Energy Trust and provide the Commission information about system design and usage forecasts.

2. Competitive Bidding

For projects greater than 100 kW, Staff proposes that the Commission defer to the FERC's jurisdiction by establishing a competitive bidding program. Under this mechanism, the transactions between the consumers and the electric companies would be within the FERC's jurisdiction. Consumers would obtain market-based rate authority from the FERC and sell power to the utilities at a VIR determined by the bidding.[6] Staff believes that a bidding mechanism should be limited to large-scale projects, because small-scale and medium-scale consumers will likely be less sophisticated and less likely to engage in a competitive bidding process.

RNP supports the use of competitive bidding for a portion of the annual capacity allocation for medium-scale and large-scale SPV systems. RNP recommends that the Commission should approve a request for proposal (RFP) process that includes prioritization of wining proposals based on proposed VIRs, geographic diversity, and system size diversity.

ELAW and OREP oppose the use of competitive bidding. ELAW contends that the bidding is not permitted, as ORS 757.365, as amended by HB 3690, requires each electric company to file "tariff schedules" for the pilot programs. ELAW explains that an electric company using the bidding process would not be able to file tariff schedules because it would not know the price at which it will buy electricity generated under the pilot programs. ELAW and OREP also criticize a bidding approach because, like the net metering proposal, it is not a feed-in-tariff contemplated by ORS 757.365.

ELAW also contends a bidding mechanism will hinder the development of the solar industry in Oregon. ELAW explains that periodic bidding is not a sustainable business model, and does not create the certainty needed to build a strong business. ELAW also believes that bidding will likely ensure that larger systems are paid at a higher rate than smaller systems, as consumers with larger systems will have the ability to ensure that the VIR will include a rate of return.

OREP contends that a bidding mechanism will require lengthy price negotiation and limits development opportunities by limiting participation to those who can

[6] In comments filed April 9, 2010, RNP and CUB report that the FERC recently issued a rule exempting generation facilities with net capacity less that 1 MW from the filing requirement for certification, meaning that the FERC market rate authority is no longer needed.

manage such negotiations. OREP favors the traditional feed-in-tariff approach, which eliminates the need for negotiations with the use of a standard contract.

OSEIA is opposed to a bidding process. OSEIA believes a bidding process will favor highly capitalized investors at the expense of less funded local companies. OSEIA also states that, by rewarding lower priced selections, a bidding process will reduce quality of projects and leave consumers with little guarantee of service.

Pacific Power, Idaho Power, and PGE are concerned that the competitive bidding approach may prove expensive and administratively burdensome. If this approach is adopted, they ask that the Commission collaborate with the electric companies to establish timelines and other guidelines for an RFP.

PGE also has concerns regarding how the bidding would work to resolve the FERC jurisdictional issue and still meet the objectives of the program. PGE raises concerns whether an RFP for only SPV systems would result in a legitimate market-based rate when not compared against all resources and if certain generators have market power. Moreover, PGE anticipates that rates among each utility RFP might vary significantly, and questions what impact this disparity might have on participation levels and market development.

3. Avoided Cost Plus

Several parties proposed a variety of mechanisms that rely, at least in part, on the Commission's authority under the Public Utility Regulatory Policy Act (PURPA). These proposals generally view the VIR as consisting of two parts: (1) an avoided cost component; and (2) an additional component based on a designated attribute or incentive associated with the electricity produced by the SPV system. We discuss each mechanism separately.

(a) REC Incentive

ELAW and OREP propose a two-part mechanism under which the consumer becomes a qualifying facility (QF) under PURPA and sells the net output of electricity generated to the electric companies at avoided costs. The electric companies would also be required to purchase Renewable Energy Credits (RECs) associated with the electricity at VIRs established by the Commission. ELAW and OREP support this mechanism because it resembles a traditional feed-in-tariff. OREP adds that setting a value on the RECs is preferable to the net metering VIR or competitive bidding approaches.

ELAW acknowledges that, under this proposal, the REC would need to be valued at levels that greatly exceed the market rate. ELAW contends, however, that this fact should not be a concern, because either the Commission is going to require the utility to pay more than the market rate for a REC, or to pay more than current market rates for electricity. In fact, ELAW suggests that, of the two choices, paying more for a REC is preferred because then the utility will have a REC that it can own and use, as oppose to paying more for electricity that, under the net metering proposal, will never even be delivered.

Staff and RNP oppose the REC incentive proposal. Although Staff believes that the Commission has the authority to impose VIR on RECs created by pilot program consumers, Staff believes that such imposition could have negative consequences. Both Staff and RNP contend that establishing a value for RECs that greatly exceed their market value could detrimentally affect how RECs are used in Oregon and other jurisdictions.

(b) Environmental Attributes

Pacific Power and Idaho Power propose that the VIR payments be characterized as consisting of two parts – the first part the company's avoided cost rate for the energy produced, and the second part based on the environmental "attributes" of the pilot program. Under this mechanism, the second payment could be set at a rate per kWh equal to the Commission's determined VIR, minus the avoided cost of energy. Because it is not clear whether the Commission has authority to establish such a rate, Pacific Power and Idaho Power suggest that the Commission could order parties to enter into contracts to establish the VIR rather than establishing rates in an order.

ELAW and OREP support this proposal along with their REC incentive proposal discussed above. ELAW states that this arrangement would allow the Commission to design a strong, simple program that would not be preempted by federal law, because the value of the "environmental attribute" is not governed by the FERC. OREP adds that the Commission could set an advisory rate for the VIR contracts that is sufficient to achieve the pilot program goals and compensate the consumers for the electricity produced.

Staff opposes the environmental attribute approach and believes it is preempted by PURPA. Staff explains that the Commission has no authority to require electric companies to enter into contracts with QFs that would provide QFs compensation in addition to compensation provided based on avoided costs—regardless of whether the compensation is based on a rate established by the Commission or through mutual agreement of the company and QF.

(c) The Energy Trust Subsidy

Under this proposal, consumers become a QF under PURPA and sell the net output of electricity generated to the electric companies at the avoided costs. The Energy Trust would then subsidize the sales price at the VIR established by the Commission. No party directly proposed this option in opening comments; however, several parties subsequently contacted Staff and expressed support for it.

Staff contends that the Commission lacks the authority to adopt this mechanism. Although the Commission may offset amounts paid by utilities with a tax credit or certain types of subsidies, it cannot offset amounts paid with a subsidy funded directly by the utilities. According to Staff, this would violate PURPA by requiring the utilities to pay QFs amounts in excess of the utilities' avoid costs.

(d) Modified Avoided Cost Calculation

In its opening comments, PGE suggests the possibility of establishing an avoided cost rate that reflects the unique characteristics of SPV systems in the pilot program. PGE suggests that these rates could be adjusted using factors enumerated by PURPA to achieve adequate levels to facilitate solar development.

Staff agrees that the Commission has the authority to establish avoided cost rates. Staff doubts, however, that the Commission can establish avoided cost rates at levels that are sufficiently high to adequately test the use of VIRs to encourage solar development. Staff explains that avoided cost rates are based on the electric companies' costs, not those of the generators.

B. Resolution

We adopt Staff's proposal to use a net metering approach for consumers with small-scale and medium-scale SPV systems and a bidding approach for all consumers with large-scale systems. We find that Staff's dual proposal is the best approach to demonstrate the use and effectiveness of VIRs for electricity produced by SPV systems under the pilot programs required by ORS 757.365 and meet our other statutory responsibilities to ratepayers.

We adopt net metering for small-scale and medium-scale consumers due to the simplicity, accessibility, and limited expense associated with such programs. We agree with the comments of many parties that these consumers will likely be less sophisticated than those installing SPV systems of 100 kW and above, and less willing or able to participate in a more complex bidding process. Moreover, like a traditional feed-in tariff, the net metering solution offers these consumers the assurance of an established rate for electricity generated by an SPV system prior to contracting with an electric company.

We share the concern expressed by many parties that a net metering approach may create an economic incentive for consumers to consume more energy to increase the size of the VIR subsidy. We do not believe that this issue is significant enough, however, to preclude the use of net metering. We agree with some commentators that the problem is likely limited in scope, because a typical rooftop SPV system is not likely to produce more electricity than an average residential consumer uses in a year.

We manage this perverse incentive problem in two ways. First, we have limited the use of net metering to small-scale and medium-scale systems. This excludes consumers with larger-scale systems who are the most likely to have an incentive to waste energy under a net metering option. Second, we limit the size of the installed SPV systems based on average consumption levels. We do not believe imposing these limits will be administratively burdensome. Nonetheless, we will monitor this issue and will, if necessary, revisit this issue in future proceedings. We address the appropriate size limitations in docket AR 538.

We acknowledge that Pacific Power, Idaho Power, and PGE have concerns about the billing and accounting difficulties of administering a net metering approach to implement ORS 757.365. We ask the electric companies to do their best to develop the billing and accounting systems as necessary to implement this order and will ask them to consult with our Staff regarding approaches to any difficulties they encounter.

We adopt a competitive bidding option for consumers with large-scale SPV systems. We believe a competitive bidding option for these consumers will avoid any FERC jurisdictional concerns because it explicitly requires the FERC market-based rate authority for sales from these systems, help achieve the goals of ORS 757.365, and will minimize the rates to be paid for electricity produced by SPV systems. We also adopt a bidding option for large-scale projects to address, in part, the perverse incentive problem associated with net metering. We address guidelines to implement a competitive bidding option for large-scale projects later in this order.

We are not persuaded by ELAW's arguments that net metering and competitive bidding options are prohibited under ORS 757.365. ELAW's first argument—that the Commission must adopt a traditional feed-in tariff—rests not on the text of the statute, but on the relating clause to HB 3690 that refers to "feed-in tariffs." The relating clause of a bill is not part of the statute itself and "cannot supply express provisions that are not otherwise in the [statute's] text."[7] A relating clause is treated like headings and explanatory notes, which "do not constitute any part of the law."[8] We note that ORS 757.365 does not contain the term "feed-in tariff," and conclude that the relating clause to HB 3690 used the term simply to generically refer to volumetric incentive payments to encourage the development of SPV systems.

ELAW's second argument—that HB 3690 shows a clear legislative desire for a traditional feed-in tariff and prohibit the use of competitive bidding—are not supported by the text and the legislative history. As ELAW acknowledges, HB 3690 was introduced to ensure that the Commission had sufficient authority to implement the pilot programs mandated by ORS 757.365.[9] The legislators were aware of the FERC preemption problem, and knew that the Commission was considering various solutions, including the use of net metering, competitive bidding, and PURPA-based options. Contrary to ELAW's arguments, the legislature did not enact HB 3690 to identify a preferred option or to preclude others, but rather to provide the Commission the necessary flexibility to adopt any of the proposed solutions. This intent was made at a public hearing when the Committee Chair sought confirmation that the HB 3690 amendments were "consistent with our intent not to direct the PUC to pick any of the options but to give the PUC the ability to choose the best option[.]"[10]

Consistent with that intent, the legislature amended ORS 757.365 in two ways to facilitate competitive bidding. First, the legislature revised ORS 757.365(2) to replace the

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[7] *Nakamoto v. Kulongoski*, 322 Or 181, 189, 904 P.2d 165 (1995).
[8] *Id.* (quoting ORS 174.540).
[9] Closing Supplemental Comments of Environmental Law Alliance Worldwide at 1 (Apr 19, 2010).
[10] Audio Recording, House Committee on Sustainability and Economic Development, HB 3690 (Feb 4, 2010, 1:44 P.M.) (Statement of Legislator Tobias Reed).

need for the electric companies to file "rate schedules" with the less specific requirement to file "tariff schedules."[11] Second, the legislature amended ORS 757.365(4) to allow the rate be established at the time a participant enrolled in the pilot program. Taken together, these two changes permit a utility to file a tariff schedule that includes a competitive bidding process, which would include the actual rate being established at the time the electric company accepts the participant's bid. Thus, ORS 757.365, as amended by HB 3690, supports the use of such tariff options as competitive bidding to test the development of SPV systems under the pilot project.

We find the dual use of net metering and competitive bidding to be superior to the other proposals that rely, at least in part, on our authority under PURPA. We acknowledge the legal merit of the proposed REC Incentive method. However, we decline to adopt it, in part, due to the risk placed on program participants and utilities if sales under the REC Incentive proposal were deemed jurisdictional by the FERC and the payments found to be in excess of what is allowed by law. Although Staff believes the Commission likely has the authority to require utilities to pay more than the market rate for RECs associated with the SPV systems, the FERC has not yet addressed the matter. In contrast, this risk does not exist with Staff's proposed dual use of net metering and competitive bidding. The FERC has expressly concluded that net metering transactions are retail transactions subject to our jurisdiction,[12] and competitive bidding defers to the FERC jurisdiction. This assurance provides the bases for successfully implementing the pilot program.

We share Staff's opinion that two other proposals—the Environmental Attribute and the Energy Trust Subsidy—are prohibited under PURPA. VIRs that include a value for the non-energy attributes of the electricity or an amount subsidized by Energy Trust would require electric companies to compensate the pilot program consumers at amounts that exceed the companies' avoided costs.

We find unworkable PGE's proposed use of PURPA factors to adjust the avoided cost rate to reflect the unique characteristics of solar power. Because avoided cost calculations are based on the company' costs—not those of the generators—the avoided costs cannot be increased under PURPA to adequate levels to test the use of VIRs to encourage solar development.

Finally, we decline to adopt any hold-harmless provisions requested by Pacific Power, Idaho Power, and PGE for three reasons. First, we do not think such provisions are necessary, as the use of use of net metering and competitive bidding VIRs adequately address the FERC jurisdictional issue and do not pose legal or regulatory risks to the electric companies or their ratepayers. Second, the inclusion of hold-harmless provisions would create uncertainty and risk to pilot program consumers, and may likely dissuade participation. Finally, this is a pilot program that we will monitor and, if necessary, modify

[11] "Rate schedules" are filings that list all rates and charges for any service provided. *See* ORS 757.205. "Tariff schedules" is a broader term and generally include the rate schedules and other provisions governing utility service, such as rules and regulations. Significantly, tariffs need not specify an exact rate. *See, e.g., Wah Chang v. PacifiCorp, dba Pacific Power*, Docket UM 1002, Order No. 09-343.
[12] *See* FERC 61,340 2001 WL 306484 (*MidAmerican Energy Holdings Co*.).

to address any change in circumstances that might create risk to the electric companies and their ratepayers.

IV. THE PILOT PROGRAM

A. The VIR

1. Initial Rates available under Net Metering

A critical element of the success of the pilot program is setting the initial rates for energy produced by small-scale and medium-scale systems under the net metering arrangements. Establishing the rates requires consideration of numerous issues, including how the rates should be calculated and whether the rates should be differentiated by size and geographic location. We address these issues separately.

(a) Rate Calculation

Parties generally support setting the initial VIRs based on the costs of the SPV systems. This cost-based VIR is derived from two components: annual system cost divided by annual energy output.

To determine its VIRs, Staff relied on system cost data provided by the Energy Trust. Staff used data from systems installed between January 1, 2008 and the third quarter of 2009, for the VIR calculations presented in its opening and closing comments. For each project in the Energy Trust database, Staff added an estimate of current loan financing costs, insurance costs, income taxes and tax preparation costs, as well as an allowance for utility meter service charges. In its supplemental comments, Staff used more recent cost data from SPV systems installed during the last quarter of 2009 and the first quarter of 2010 for its VIR calculations. Due to reduced costs of SPV systems, Staff's revised its proposed rates to lower the per kWh rate by 10 cents for small systems in rate zone one.

Staff estimated the annual energy output of each SPV system in the database using solar radiation factors associated with four geographic zones in Oregon. The four geographic zones were aligned with county boundaries and were selected based on solar radiation, utility service territories, and database sample sizes. Staff closely followed the methodologies and recommendations of the Energy Trust when choosing the radiation factors and geographic zones.

Staff calculated a VIR for each SPV system in the Energy Trust database to provide a range of possible VIRs. Under the belief that the Commission should be conservative in setting the initial rate, Staff recommends rates set at the 25th percentile of the range of VIRs.

OREP also supports the use of cost-based rates. OREP uses the same geographic zones as Staff and includes many of the same cost elements in its VIR calculations. OREP's calculated VIRs are slightly higher than Staff's due largely to the use of higher loan financing costs and the inclusion of a return on investment.

OREP objects to Staff's recommendation to use the 25th percentile from the Energy Trust data. OREP contends that rates based on data from the 25th percentile will result in VIRs that are non-economic for three-quarters of those who might want to invest in SPV systems. Because the use of actual data from recently installed systems decreases the risk of setting the rates too high, OREP proposes rates be set at the 50th percentile.

PGE uses a "matching incentive" approach, as well as a "cost-based" approach, to calculate incentive rates. The "matching incentive" approach sets the VIR equivalent to the current tax credit and rebate incentives made available to solar net metering or QF customers in Oregon. The "cost-based component" is calculated using industry data. PGE warns that a pilot program rate that is substantially higher in value than current incentives may well supplant the current net metering activity levels. PGE proposes that VIRs be based on the average of its "matching incentive" and "cost-based" rates.

RNP expresses concerns about the difficulty in estimating SPV system costs, and explains that solar systems have a wide variance in costs and returns at any one time, and even more variability over time. For this reason, RNP states that the VIR adjustment mechanism is as critical as the initial VIR.

We find that the cost of installed SPV systems is the necessary starting point for rates for small-scale and medium-scale systems under the pilot programs. A rate that does not allow the seller the opportunity to recover the cost of a project will not induce the needed investment in the facilities and might render the pilot program ineffective. We also find the use of Energy Trust data from recently installed systems to be the most accurate measure of costs for purposes of setting initial VIRs.

We acknowledge the risks of setting the initial rates too high or too low. Setting rates that are too low will fail to encourage the necessary investment in SPV systems. Setting the rate too high will fail to spend ratepayer dollars in a cost-effective manner. Given the uncertainty as to what rate levels are required to draw a reasonable level of participation, we chose the conservative path. Setting the initial VIRs at the lower range of rates is consistent with the desire to promote efficient SPV systems. In addition, as Staff notes, the consequences of setting rates too high cannot be undone. Eligible capacity will be reserved without recourse for ratepayers. In contrast, rates set at levels too low to promote participation can be raised during later stages of the pilot program. We address how the VIRs may be adjusted below.[13]

(b) Rates by Project Size

Consistent with setting rates based on cost, Staff and other parties propose to differentiate rates based on project size. As noted above, in HB 3690 the legislature defined

[13] The rate itself will be set for the full 15-year contract term. However, any rate for new contracts will be available only until the Commission adopts a new rate.

a "residential qualifying system" as a qualifying system with a nameplate capacity of 10 kW or less, and a "small commercial qualifying system" as a qualifying system with a nameplate capacity greater than 10 kW and less than or equal to 100 kW. Staff's rate proposal derives proposed rates for the residential qualifying systems (small-scale) and small commercial qualifying systems (medium-scale).[14]

We adopt Staff's proposed rate classification, which include lower rates for the medium-scale projects to reflect the lower installed cost associated with larger projects.

i. Piecemealing

We add certain clarifications to Staff's proposal to address an unintended consequence of setting rates in this manner. The unintended consequence is the possibility that project developers could "piecemeal" their projects to obtain a higher rate. For example, rather than build one 20 kW project at one site, a developer could build two 10 kW projects and obtain a higher rate. Such a practice would be contrary to our goals of encouraging efficient development of SPV systems while minimizing program costs.

To address this issue, we adopt as a general rule a limit of one generation meter per consumption meter at any one site. This meter restriction is consistent with the concept of net metering and will help eliminate the ability of developers to piecemeal a project solely for the purposes of obtaining a higher rate. We clarify that this is only a general rule, and will allow the utilities the discretion to allow multiple generation meters per consumption meter where the applicant can show a bona fide commercial purpose or financial reason for installing more than one system and where the amount of the capacity associated with the second generation meter, combined with the amount of capacity measured at the first generation meter, is less than maximum capacity in that rate class. For example, if a consumer already has a 5 kW system and wishes to add a second system with a capacity of 3 kW, the combined capacity—8 kW—is less than the capacity ceiling for the small scale project rate class—10 kW, so the one generation meter restriction per site would not apply.

(c) Rate Zones

Given the correlation between solar radiation and energy output, we must decide whether to differentiate rates by geographic area. In the small-scale system size category, Staff proposes different VIRs for each of its four geographic zones. Under Staff's proposal, PGE would have two rate zones, Idaho Power would have a single rate zone, and Pacific Power would have four rate zones. In the medium-scale size category, because the sample sizes of SPV systems is not robust across geographic zones, Staff proposes a single VIR for the entire state.

PGE opposes geographically differentiated solar rates. PGE recommends, for a particular project size, a single volumetric rate for the entire state.

[14] The rates for projects greater than 100 kW will be set by competitive bidding.

We adopt Staff's proposed recommendations. Staff's proposal allows us to test both approaches and learn whether geographical differentiation is important to economically deploying SPV systems in a wide range of areas.

(e) Resolution

For reasons discussed above, we adopt the following cost-based VIRs for small-scale and medium-scale systems, as differentiated by project size and location:

Rate Class	**Counties**	**Electric Companies**	**Small-Scale Systems (≤10kW)**	**Medium-Scale Systems (>10kW and ≤100kW)**
1	Benton, Clackamas, Clatsop, Columbia, Lane, Lincoln, Linn, Marion, Multnomah, Polk, Tillamook, Washington, and Yamhill	Pacific Power and PGE	0.65/kWh	0.55/kWh
2	Coos, Douglas, and Hood River	Pacific Power and PGE	0.60/kWh	0.55/kWh
3	Gilliam, Jackson, Josephine, Klamath, Morrow, Sherman, Umatilla, Wallowa, and Wasco	Pacific Power	0.60/kWh	0.55/kWh
4	Baker, Crook, Deschutes, Jefferson, Lake, Malheur, and Harney	Pacific Power and Idaho Power	0.55/kWh	0.55/kWh

Because these rates apply to systems participating in the pilot programs under the net metering option, we clarify that the VIRs shown above are not the rates that the consumers will actually be paid for generation. The net VIR under a net-metering arrangement is the applicable VIR minus the consumer's retail rate in effect at the time the generation is netted against consumption.[15] This calculation is represented by the following formula:

Net volumetric incentive rate = (volumetric incentive rate$_e$ – retail rate$_p$)

Where: e = rate at time of enrollment, and
p = time of payment

Without this netting, ratepayers would be effectively paying more than the VIR in the above table because the generation will offset consumption and reduce the customer's bill.

[15] *See* Staff Opening Comments at 18 & 21.

4. Rate Changes for Net Metering Arrangements

Now that we have established initial VIRs for small-scale and medium-scale systems, we turn to mechanisms to adjust the rates to respond to participation levels throughout the maturation of the pilot program.

Staff recommends a rate-adjustment mechanism be applied every six months using three capacity reservation "zones" to determine the presumed, yet rebuttable, VIR adjustment. If less than 50 percent of the available capacity[16] for the system size class is reserved after a five-month period, then the VIR would be increased by 10 percent for the subsequent rate period. If more than 50 percent, but less than 75 percent of the available capacity is reserved after a five-month period, then the VIR would be increased by 5 percent for the subsequent rate period. If more than 75 percent, but less than 100 percent of the available capacity is reserved after a five-month period, then the VIR would not be changed.

Staff further recommends that, if 100 percent of the available capacity is fully subscribed after a five-month period, then the VIR would be decreased for the subsequent rate period depending upon how quickly the full subscription level was achieved. If full subscription was achieved in less than three months, then the VIR would be decreased by 10 percent. If full subscription was reached between months three and five, then the VIR would be decreased by 5 percent. No VIR adjustment would be prescribed if full subscription was achieved during the sixth month of the rate period. Each electric company would be required to notify the Commission of its subscription levels for small-and medium-scale systems no later than five business days after the end of the fifth month of every six-month rate period.

Pacific Power and Idaho Power recommend rate adjustments based on market conditions. They propose rates be evaluated on an annual basis, with a six-month progress report to take an assessment of the program's success.

RNP proposes a "hardwired" price adjustment mechanism that automatically, but predictably, reacts to the actual price of the resource. RNP proposes quarterly MW allocation limits, with a price reduction of no more than 10 percent if the allocation is fully subscribed. CUB also supports quarterly price changes.

We find Staff's proposed rate adjustment mechanism superior to the proposal offered by other parties and adopt it. A quarterly review process would be administratively burdensome and difficult given the complexities associated with adjusting rates. Any benefits to ratepayers by reducing the VIRs would be offset by the administrative costs of the program. An annual rate adjustment mechanism lacks the necessary flexibility to correct rates in an effective and timely manner to address program participation and market conditions. In contrast, Staff's six-month adjustment window, with rebuttable price adjustments correlated to changes in capacity availability, provides a workable and reasonable means to adjust the VIRs as necessary to meet the goals of the pilot programs.

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[16] We use the term "available capacity" to mean the amount of capacity allocated to that six-month period. See discussion below under the heading "Capacity Rationing."

5. Competitive Bidding VIR

As stated above, we adopted Staff's proposal for competitive bidding for projects greater than 100 kW, with the sales expressly subject to FERC's jurisdiction. We must also address the process to be used to establish the VIR through competitive bidding.

Staff proposes that utilities would solicit bids annually, using an RFP process approved by the Commission. Staff proposes the following structure for competitive bidding and asks that the Commission adopt a price cap bid:

a. Electric companies should develop and file for Commission approval a draft RFP for large-scale systems,

b. Bid scoring and evaluation are based primarily on price without adjustment for non-price factors,

c. Bidding should be capped at the VIR for small commercial systems,

d. Bids are selected from lowest VIR to highest, until the capacity target is achieved, and

e. No single developer, financer, retail electric consumer may exceed its capacity limit under the pilot program.

PGE recommends that we adopt clear bidding goals and simple bidding requirements and guidelines. Pacific Power and Idaho Power ask that the Commission establish prudency criteria to be applied in a subsequent regulatory review of a competitive bidding process. They also request that electric companies be allowed to contract with a third-party to assist in the bidding process.

RNP proposes that the bidding process include consideration of non-price factors, including geographic diversity and system size diversity. RNP also recommends that bids from an aggregation of systems be allowed, as long as the combined nameplate capacity of aggregated systems exceeds 100 kW and is less than or equal to 500 kW.

We adopt Staff's proposal. We do not support the use of non-price factors in bid evaluations because it will add complexity, with little or no benefit, to the pilot program. We also decline RNP's recommendation to allow aggregated systems to offer bids. At the same time, we will revisit this issue, as necessary, later in the pilot program.

We require sellers to bid prices only. All other contract terms must be uniform among sellers and identical to the standards contracts for sellers under the net metering arrangements with the exception of prices. We expect the electric companies to develop their own policies, and direct them to submit a draft RFP process for our review within 30 days of entry of this order. Electric companies may contract with third-parties to assist in the RFP process. With respect to the prudence issues raised by Pacific Power and Idaho Power, all electric company purchases from the winning bidders are presumed reasonable.

We find that a price cap should be applied to the bids, at least for the first year of the pilot program. This will protect consumers from the possibility of paying exorbitant prices due to poorly designed or executed bidding schemes. Because we anticipate that the cost of large-scale systems will not exceed the cost of medium-scale systems used to set the cost-based rate for net metering arrangements, we adopt a price cap equal to the VIR for medium-scale systems (55 cents/kWh).

B. Capacity

1. Capacity Rationing

Staff proposes that the Commission ration the capacity availability over a four-year period (6.25 KW per year). RNP proposes a two-year period—12.5 KW per year. RNP is concerned that Staff's proposal could unnecessarily slow "the development of the solar industry in Oregon."[17] RNP believes that a faster capacity deployment would maximize the development of the solar industry in Oregon. CUB suggests a compromise—a three-year period.

We adopt Staff's proposal for two primary reasons. First, we want this pilot project to maximize what we can learn from the use of VIRs to encourage the development of SPV systems. A longer rationing period will give us more time to learn from our initial design and, if necessary, make adjustments as necessary to ensure the program's success. Second, we want this pilot project to be as cost effective as possible. A longer rationing period is consistent with our goal of minimizing program costs as the Commission and interested parties will have opportunities to adjust the pilot projects as needed.

We modify Staff's proposal in one respect, however. As stated above, we have adopted a six-month rate adjustment mechanism for small-scale and medium-scale systems that will participate in the pilot program under the net metering option. To facilitate this mechanism, the capacity available to these systems will be allocated biannually during the four-year period, for a total of eight allocations (October 1 and April 1 of each year).[18] As proposed by Staff, the available capacity for large-scale systems will be allocated on a yearly basis.

[17] ORS 757.365(7).

[18] We note that, due to the HB 3690 amendments to ORS 757.365, the first capacity allotment will be made on July 1, 2010, then again on October 1, 2010.

2. Allocation of Capacity among Companies

Staff proposes that the pilot program capacity of 25 MW be allocated among the electric companies based on their share of 2008 retail sales revenue. The resulting allocation is:

PGE	14.9	MW
Pacific Power	9.8	MW
Idaho Power	0.4	MW

Staff also proposes that all of the Idaho Power allocated capacity be allocated to residential qualifying systems.

Idaho Power questions Staff's proposed allocation among the electric companies. According to Idaho Power, its administrative costs alone will exceed the 0.25 percent of revenue cap identified in ORS 757.365. Thus, it argues that its allocated share should be reduced to 100 kW to limit the impact on its Oregon ratepayers.

RNP questions Staff's proposal to allocate all of Idaho Power's allotted capacity to residential qualifying systems. RNP argues that small commercial scale projects should also be allowed in Idaho Power's program.

We adopt Staff's proposed allocation based on sales revenues. We make no adjustment to Idaho Power's allocation. While we are mindful of costs, Idaho Power will incur administrative costs regardless to manage any level of program. As with the other program design elements, we will monitor costs and revisit this issue, as necessary, after we gain experience.

Further, because of the relatively small capacity allocation assigned to Idaho Power, we adopt Staff's proposal to limit eligible systems in the Idaho Power service area to residential systems.

3. Allocation of Capacity by Project Size

Under ORS 757.365(6), the pilot programs must be designed to allocate at least 75 percent of the total capacity to residential qualifying systems (10 kW or less) and small commercial qualifying systems (100 kW or less). We must determine the overall allocation of capacity to the small-scale and medium-scale classifications, as well as the allocation of that amount between them.

Staff proposes to allocate 80 percent of the program capacity (20 KW) to these two classifications—12 KW to residential scale, and 8 KW to small commercial scale (and 5 KW to large-scale projects), along with its proposed four year phase in. Staff proposes these measures to investigate whether the pilot program can attract participation across diverse geographic locations, with diverse ownership models, by diverse developers with diverse SPV technologies. According to Staff, if the program capacity is rapidly deployed to entities already positioned to fill the capacity in a concentrated location, using one or two business models, much less may be learned.

RNP proposes to allocate 6 MW of capacity to residential scale projects, 13 MW to small-scale commercial and 6 MW to large-scale installations. RNP argues that Staff's proposal does not allow for a sufficient number of medium-scale installations to meet the pilot program's learning objectives. RNP also is concerned that Staff's proposal will increase program costs without significantly improving the findings to be derived from the program.

OREP is concerned that the overall program has moved away from the Governor's original goal of "making solar more affordable for individuals and communities." OREP believes that, for the program to be palatable to its "main funders—residential ratepayers"—the pilot program should include a high level of participation by small-scale projects. ELAW similarly requests that most of the allocation focus on residential systems.

We adopt Staff's proposal. We believe that Staff's allocation is the most suitable for use in a pilot program. It will generate adequate participation by all classes and provide the most information for evaluating the VIR approach.

4. Preferential Rate or Capacity Carve-Out for Non-Profit Organizations and Agencies

As noted by EMO, the cost-based rate methodology for setting the VIR incorporates a federal tax credit that is not available to entities that are not themselves taxpayers—such as non-profit corporations and government agencies (non-profits). EMO proposes a higher rate for such entities, as well as a capacity carve out that sets aside a portion of the capacity for such projects.

Several other parties support a higher rate or capacity carve-out, or both. Staff proposes that non-profits be allowed to reserve capacity in the same manner as participants with residential scale projects (at any time).

We decline to adopt either a preferential rate or capacity carve-out for non-profits. Recently proposed changes to the federal tax laws may well address the concerns about project economics raised by EMO and others by allowing non-taxpaying entities the ability to receive the tax credit benefits by partnering with a tax-paying entity.[19] Further, we find no reason to adopt Staff's proposal for a special capacity reservation system for non-profits. We will monitor these issues and, if necessary, reconsider our decisions during later stages of this pilot project.

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[19] We understand that Senate Bill 3137, introduced March 18, 2010, and referred to the Senate Finance Committee, would amend the federal tax code to allow solar energy installations on the property of not-for-profit enterprises to qualify for the energy tax credits by partnering with a for-profit entity.

C. Permanently Installed

ORS 757.365(1) requires that qualifying systems be "permanently installed." Staff and other parties recommend that the project remain in service for the remainder of its useful life.

We agree that the legislature intended that projects remain in service beyond the term of the pilot programs. Staff's proposal is adopted.

D. Ownership

Staff and other parties recommend that electric companies and their affiliates not be allowed to participate as sellers in the pilot programs. PGE, Pacific Power, and Idaho Power oppose Staff's position. Pacific Power and Idaho Power assert that only the legislature can decide to prohibit electric companies from participating in the pilot programs.

Pacific Power and Idaho Power have cited no support for their assertion that this Commission cannot limit utility participation in the program, and we find no such prohibition. To the contrary, the legislature has given this Commission broad power to establish the pilot programs consistent with provisions of ORS 757.365.

We adopt Staff's proposal to exclude electric company ownership. The administrative burden that will likely be incurred to undertake affiliated interest reviews of electric company participation in the pilot program does not justify company participation. We do make one modification to Staff's proposal, however, by allowing the affiliates of the electric companies to participate in pilot projects outside the respective service territories of the affiliates' parent companies.

E. Cost Recovery

ORS 757.365(10) provides that "all prudently incurred costs" associated with the pilot programs are recoverable in rates by the utilities. PGE and Pacific Power each have proposed a cost recovery mechanism that is consistent with their current automatic adjustment clause practices. Their proposals are reasonable and are adopted.

Idaho Power has not developed an automatic adjustment clause to recover renewable costs. The Company asks that it be allowed to recover 100 percent of its costs through a rider mechanism similar to its currently approved Energy Efficiency Rider. Idaho Power's request is granted.

F. System Quality

Staff's proposed rules in docket AR 538 require pilot program systems to meet quality and service standards established by this Commission. Staff, Pacific Power, Idaho Power, RNP, and OREP support the use of the standards applied by the Energy Trust and ODOE for SPV systems. We adopt those systems quality standards.

G. Cost Allocation

ICNU argues that the pilot program costs should be allocated among customer classes in proportion to each class's benefit from and participation in the program. We do not decide cost allocation issues in this proceeding. Cost allocation issues will be taken up at the time when pilot program costs are to be amortized in rates.

H. Monthly Service Fee

PGE recommends a monthly service charge for each SPV system meter of $10 per month. PGE notes this is the same charge for QFs selling power to PGE under PURPA.

We adopt PGE's recommendation, as Staff included a monthly meter fee in its cost-based rate for net metering arrangements.

V. ORDER

IT IS ORDERED that:

(1) Portland General Electric Company, PacifiCorp, dba Pacific Power, and Idaho Power Company must file all tariffs and applications necessary to implement their respective pilot program, including those necessary to implement the volumetric incentive rate net-metering and bid options, semi-annual rate adjustment windows, the rate adjustment mechanism, capacity reservation processes, cost recovery mechanism, and others as required under the terms of this Order, to be effective July 1, 2010;

(2) Within 15 days of the date of this order Portland General Electric Company, PacifiCorp, dba Pacific Power, and Idaho Power Company each must file a draft RFP for the Public Utility Commission of Oregon's review and approval; and

(3) Portland General Electric Company, PacifiCorp, dba Pacific Power, and Idaho Power Company may choose to file applications under ORS 757.259 to defer costs related to the pilot program for later amortization in rates.

Made, entered, and effective MAY 28 2010.

Ray Baum
Chairman

John Savage
Commissioner

Susan K. Ackerman
Commissioner

A party may request rehearing or reconsideration of this order pursuant to ORS 756.561. A request for rehearing or reconsideration must be filed with the Commission within 60 days of the date of service of this order. The request must comply with the requirements in OAR 860-014-0095. A copy of any such request must also be served on each party to the proceeding as provided by OAR 860-013-0070(2). A party may appeal this order by filing a petition for review with the Court of Appeals in compliance with ORS 183.480-183.484.