BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

AR 538 AND UM 1452

In the Matter of PUBLIC UTILITY COMMISSION OF OREGON Investigation into Pilot Programs to demonstrate the use and effectiveness of Volumetric Incentive Rates for Solar Photovoltaic Energy Systems.	)))))))))	COMMENTS OF RENEWABLE NORTHWEST PROJECT AND PARTNERS ON PUC STAFF'S STRAW PROPOSAL FOR FEED-IN TARIFF DESIGN

I. Introduction

Renewable Northwest Project (RNP) appreciates the opportunity to provide the following comments on the Staff's straw proposal. RNP is a non-profit advocacy organization promoting solar, wind and geothermal resources in the four Northwest states. RNP's members are a unique combination of environmental and consumer organizations as well as a variety of businesses engaged in the development of renewable energy projects. RNP developed these comments in partnership with the Citizens' Utility Board of Oregon, the Oregon Solar Energy Industries Association, SolarCity, Tanner Creek Energy, enXco, SunEdison, SolarCity, REC Solar, Obsidian Renewables, SunPower, Sunlight Solar, Sunergy Systems, Real Energy Solutions and the International Brotherhood of Electrical Workers Local 48.

We commend Staff's intention of offering the straw proposal as a framework for all parties to comment and make recommendations to the proposed Division 084 (AR 538) rules and proposed Commission decisions in UM 1452. We have structured our comments to mirror the subject areas referred to in the straw proposal. Our substantive comments are followed by recommended revisions to the proposed Division 084 (AR 538) rules in the Appendix.

We encourage the Commission to consider our recommended alternative proposals regarding: the system size categories for qualifying systems, distribution of the energy generated by installed systems, deployment of pilot program capacity, setting and adjusting the Volumetric Incentive Rate (VIR), administration of the VIR, application requirements, and application selection.

We believe our alternative proposals, when taken as a whole, will "demonstrate the use and effectiveness of volumetric incentive rates and payments for electricity delivered from solar photovoltaic energy systems that are permanently installed in this state…" (Section 2(1) of HB 3039) and "evaluate the effectiveness of paying incentive rates under the pilot programs…compared to incentive rates [Energy Trust of Oregon incentives, the Residential Energy Tax Credit and the Business Energy Tax Credit] for promoting the use of solar photovoltaic energy systems and reducing system costs." (Section 2(13) of HB 3039). We also believe that our alternative proposals will result in pilot programs that successfully "increase the use of solar photovoltaic energy systems, make them more affordable, reduce the cost of incentive programs to utility customers and promote the development of the solar industry in Oregon." (Section 7 of HB 3039). Finally, we believe that over time, our alternative proposals will achieve sustainable growth, higher performance ratios, and declining costs for solar photovoltaic energy systems in Oregon.

II. Solar Capacity Standard

We agree with the straw proposal recommendation that no Commission decisions need to be made regarding the Solar Capacity Standard.

III. Pilot Program Participation

We agree with Staff's recommendation that pilot program participants should be retail electricity consumers who install qualifying photovoltaic systems and enter into a standard contract with their utility to receive a volumetric incentive rate payment for energy generated and provide renewable energy certificates to the utility.

We recommend revisions to the proposed rules' definitions pertaining to "Equipment package", "Nameplate capacity", "IEEE standards", "Reservation start date", "System requirements" and "Resource value" (OAR 860-084-0010 and OAR 860-084-0240). We also recommend proposed revisions to "Ownership and Installation" (OAR 860-084-0130). It is important to note that the statute and proposed rules (OAR 860-084-0110) allow for qualifying systems to be connected to customer load (i.e. a net metered system). Specifically, the statute defines a qualifying system as a solar photovoltaic energy system that "…indirectly connects through the system of an electric company's retail electricity consumer…" (Section 1(b)(B)).

Should it be necessary to more fully define the term "permanently installed", we refer the Commission to the California Solar Initiative Handbook[1], which contains well-considered criteria for permanence. We recommend these criteria be considered and adapted as appropriate.

We also note that the amount of "system requirements" associated with a photovoltaic system is truly *de minimis* and not readily metered. The administrative complexity associated with separately creating and tracking renewable energy certificates associated with system requirements likely outweighs the value of the certificates themselves. We recommend that references to these "system requirements" be removed in the proposed rules in favor of a simple requirement that all kilowatt-hours produced by qualifying systems be generated by the eligible participant and associated technology.

IV. Capacity Reservation and Interconnection

We agree with the proposed rules' recommendation to have a consumer become a pilot

[1] www.gosolarcalifornia.org/documents/CSI_HANDBOOK.pdf

program participant by reserving capacity in the pilot program from its utility. We also generally agree with proposed rules detailing the interconnection process and the responsibilities utilities may impose on consumers (OAR 860-084-0310 through 0340 and OAR 860-084-0260 through 0300 and OAR 860-084-0350). We recommend specific revisions to the proposed rules regarding the certification standards in OAR 860-084-0260 and reasonable costs in OAR 860-084-0290.

We recommend an alternative proposal regarding system size categories for qualifying systems, distribution of capacity by system size categories, application requirements and application selection. Before describing our alternative proposals, we have included a legal analysis of HB 3039 regarding the term "smaller-scale qualifying systems" and the goal of attaining "75 percent of the energy under each program to be generated by smaller-scale qualifying systems within the allowed generating capacity range."

a. "Smaller-Scale Qualifying Systems" Is Different from and Includes "Small-Scale Qualifying Systems"

The term "smaller-scale qualifying systems" became a part of HB 3039 as a part of the Conference Committee Amendments to B-Engrossed House Bill 3039, dated June 22, 2009. Prior to the amendments, § 2(6) of B-Eng. HB 3039 provided:

> The commission shall establish pilot programs designed to attain a goal of 75 percent of the energy under each program to be generated *by small-scale qualifying systems*. The commission by rule shall define the size of a *small-scale qualifying system* and may adjust the definition of size for *small-scale qualifying systems* based upon the costs of the energy generated, the feasibility of attaining the goal and other factors. The commission may also adjust the maximum percentage goal of energy generated by *small-scale qualifying systems* based upon the same factors.

The Conference Committee Amendments made the following amendment:

> In line 31, delete "small-scale qualifying systems" and insert "smaller-scale qualifying systems within the allowed generating capacity range".

Conference Committee Amendments to B-Engrossed House Bill 3039, dated June 22, 2009, at 1, lines 10-11.

There are three important details about this amendment. First, while deleting the term from the specified locations, the amendment left "small-scale qualifying systems" in the three other places the term appears in subsection (6). By doing so, the amendment created two different sizes of qualifying systems: small-scale qualifying systems and smaller-scale qualifying systems. If it had been the intention of the Legislature to specify just one "small-scale qualifying system," there would have been no reason for the amendment. State v. Wright , 112 Or App 567, 570, 829 P2d 93, aff'd 315 Or 124, 8343 P2d 436 (1992) (When the legislature uses different language in similar statutory provisions, we presume that it intended the phrases to have different meanings.").

Second, by using "smaller" and "small" it seems apparent that the term "smaller-scale qualifying systems" includes not only "small-scale qualifying systems" but larger systems as well.

Third, the term "smaller-scale qualifying systems" is only used in connection with the 75% goal—that is, the pilot programs that the Commission establishes for each electric company are to be designed so that 75% of the energy can be generated by "smaller-scale qualifying systems." That means the 75% goal can be met by energy generated by "small-scale qualifying systems" as well as the larger systems that make up the "smaller-scale qualifying systems."

b. The Commission Should Apply Specific Criteria to Determine the Meaning of "Small-Scale Qualifying Systems"

In subsection (6), the Legislature expressly delegated to the Commission the authority "by rule to define the size of a small-scale qualifying system." The Commission also gave the

Commission authority to “adjust the definition of size for small-scale qualifying systems” based upon two specific factors and one general factor:

(1) “the costs of the energy generated”; (2) “the feasibility of attaining the goal”; and (3) “other factors.” Section 2(6) provides:

> The commission shall establish pilot programs designed to attain a goal of 75 percent of the energy under each program to be generated by smaller-scale qualifying systems within the allowed generating capacity range. The commission by rule shall define the size of a small-scale qualifying system and may adjust the definition of size for small-scale qualifying systems based upon the costs of the energy generated, the feasibility of attaining the goal and other factors. The commission may also adjust the maximum percentage goal of energy generated by small-scale qualifying systems based upon the same factors.

Because of this express delegation, it is worthwhile for the Commission to take note of *Springfield Education Assn. v. School Dist.*, 290 Or 217, 621 P2d 547 (1980). There, the Supreme Court noted that the legislature may choose to delegate the authority to an agency to “complete” “non-completed legislation,” where the legislature “cannot foresee all the situations to which the legislation is to be applied and deems it operationally preferable to give to an agency the authority, responsibility and discretion for refining and executing generally expressed legislative policy.” The Supreme Court said that when the legislature has delegated the authority, the “task of the agency administering such a statute is to complete” or refine “the general policy decision.” 290 Or at 228-29.

Although not expressed, the Commission, necessarily, has to decide what “smaller-scale qualifying systems” means as well.

The Commission’s decision about what “other factors” it should rely upon to define the terms “small-scale qualifying systems” and “smaller-scale qualifying systems” are should be informed by all of the relevant policies built into HB 3039, in particular: (1) “to demonstrate the use and effectiveness of volumetric incentive rates and payments for electricity delivered from solar photovoltaic energy systems"; (2) to provide that the "cumulative nameplate capacity of the qualifying systems enrolled in all of the pilot programs [does] not exceed 25 megawatts of alternating current"; and (3) to take into account that the maximum qualifying systems that can be used to generate the remaining 25% of the 25 MW goal "may not have nameplate generating capacity greater than 500 kilowatts." § 2(1). It is also appropriate for the Commission to define the sizes of the systems "to enable the development of the most efficient solar photovoltaic energy systems." *See* § 2(3) (dealing specifically with incentive rates). Finally, the Commission should set the sizes "to increase the use of solar photovoltaic energy systems, make them more affordable, reduce the cost of incentive programs to utility customers and promote the development of the solar industry in Oregon." § 7 (dealing specifically with the Commission's reports to the legislature).

While the task of defining "small-scale qualifying systems" has been delegated to the Commission, it is worth noting that legislators made comments suggesting that small-scale could be as large as 500kW. On June 25, describing an earlier version of HB 3039, Senator Metzger (~11:24) said on the Senate floor, "Directs the PUC to develop two pilot programs for the generation of solar power. One pilot program provides incentives for the production of solar power from small systems up to 500 kW."

c. The Terms "Small-Scale Qualifying Systems" or "Smaller-Scale Qualifying Systems" are Not Limited to Systems Installed by *Residential* Retail Electricity Consumers

Nothing in HB 3039 restricts either "small-scale qualifying systems" or "smaller-scale qualifying systems" to systems installed by *residential* retail electricity consumers. HB 3039, by its terms, requires the Commission to "establish a pilot program for each electric company to demonstrate the use and effectiveness of volumetric incentive rates and payments for electricity delivered from solar photovoltaic energy systems that are permanently installed in this state by *retail electricity consumers*….” If it had been the intention of the legislature to limit any part or all of the pilot program to qualifying systems installed by *residential* retail electricity consumers, the legislature could have done so.

This reading is confirmed by the legislative history, where both residential and commercial installations are discussed. While installation of qualifying systems by residential consumers is certainly discussed, installation by commercial consumers is as well. For example, on June 12, Senator Bonamici said (~36:18) “I’m encouraging the PUC to set feed-in tariff rates at a level that will encourage enterprising Oregonians and small Oregon businesses to invest in this important source of renewable energy.” On June 24, 2009, Rep. Read said (~1:22) on the House floor, “This is a mechanism by which people who choose to install solar technology in their homes and businesses are paid at a rate set by the PUC for the power that's generated by that.”

ORS 174.010 directs the courts in construing a statute “not to insert what has been omitted, or to omit what has been inserted.” This admonition applies with equal force to the Commission when construing statutes and it is inappropriate for the Commission to insert the word “residential” into HB 3039 or interpret “smaller-scale” to mean “residential” in HB 3039.

Alternative proposal: “Smaller-scale qualifying systems” should be defined as systems with a nameplate capacity of less than or equal to 100 kW and “small-scale qualifying systems” should be defined as systems with a nameplate capacity of less than or equal to 10 kW.

Deployment of a range of qualifying systems with a nameplate capacity equal to or less than 500 kW is consistent with the intent of the stated purpose of the pilot program, which is to "demonstrate the use and effectiveness of volumetric incentive rates and payments for electricity delivered from solar photovoltaic energy systems that are permanently installed in this state…" (Section 2(1) of HB 3039). The qualifying systems eligible for the program should also be designed to "evaluate the effectiveness of paying incentive rates under the pilot programs…compared to incentive rates [Energy Trust of Oregon incentives, the Residential Energy Tax Credit and the Business Energy Tax Credit] for promoting the use of solar photovoltaic energy systems and reducing system costs." (Section 2(13) of HB 3039).

Currently, photovoltaic energy systems eligible for both Energy Trust of Oregon incentives and a Residential Energy Tax Credit or Business Energy Tax Credit are systems with a nameplate capacity of greater than 0 kW up to 800 kW for aggregated public and non-profit systems. These systems are suited for a wide range of residential, commercial and public/non-profit markets. The qualifying systems for the pilot programs should also be suited for a similar range of residential, commercial and public/non-profit markets – especially if a direct comparison is to be made between the two incentive schemes.

We recommend defining "smaller-scale qualifying systems" as systems with a nameplate capacity of less than or equal to 100 kW. "Small-scale qualifying systems" should be defined as systems with a nameplate capacity of less than or equal to 10 kW to encompass the residential market. The Commission should define "medium-scale qualifying systems" as systems with a nameplate capacity of greater than 10 kW and less than or equal to 100 kW to encompass the commercial market. The Commission should define "large-scale qualifying systems" as systems with a nameplate capacity of greater than 100 kW and less than or equal to 500 kW to encompass the large commercial market. All of the aforementioned system size categories should be applicable to the public/non-profit market.

Alternative proposal: Distribution of capacity should be tied to system size, VIR rate setting, and application requirements and selection.

We agree with the proposed rules' recommendation requiring each electric company to allocate a percentage of its annual pilot capacity allocation, establishing the percentage by Commission Order, and authorizing the Commission to change this percentage over the pilot program. However, we are concerned that the proposed approach to distribution of capacity will not sufficiently "demonstrate the use and effectiveness of volumetric incentive rates and payments for electricity delivered from solar photovoltaic energy systems that are permanently installed in this state…" (Section 2(1) of HB 3039)

We are especially concerned about the proposed recommendation for random drawings, particularly for medium and large-scale qualifying systems. A random drawing of commercial systems would ultimately require ratepayers to bear a significant risk premium. The development of a small or medium-sized commercial solar system involves significant expenditure on the part of a solar installer or developer in legal fees, site visits, and design and engineering work, etc. The reservation requirements specified elsewhere in the rules reinforces this by requiring that a project be relatively well developed and concrete before an application is submitted.

The proposed method would require solar developers to literally gamble these pre-construction investment dollars. A larger developer may be able to survive in such an environment by simply preparing a larger number of projects and inflating the price of each to cover the risk that any given number of projects will not be selected. Developers without the resources to make these expenditures and develop such a portfolio approach, or those who simply have poor "luck of the draw" could be put out of business. Instead, we recommend that all applicants for a qualifying system be required to provide a reasonable deposit, a signed contract, proof of site control, and use of licensed, bonded contractors upon submission of the application. Applicants should also be required to comply with a rigorous deadline by which the system must be installed, as in the proposed rules pertaining to capacity reservation, timing and duration.

In addition to these measures to limit the number of applications (to ensure the programs' limited funding is delivered to the highest-quality projects), we propose several alternatives to manage pricing and approvals in the event of oversubscription. In all of our alternatives, we recommend that prices be adjusted according exclusively to real-world program participation and that the application process itself screen out projects that are unlikely to reach fruition. Lack of participation-based price adjustment and a rigorous application process has been a significant challenge in the development of some recent VIR and FIT policies in the US and overseas. Without these measures in place, program capacity reservations have been filled in a matter of hours or days, which poorly serves industry development and may result in a low ratio of systems built as compared to systems reserved.

- **Incentive reservations should be limited to viable systems**

Without adequate safeguards, any incentive program can become quickly flooded with applications – a developer will acquire the incentive first and line up other key variables (construction resources, panels, labor, financing) afterwards. This was made most evident in the Spanish Feed-In-Tariff market for 2009, where insufficient policing of the viability of FIT applications led to massive oversubscription and significant inability to complete projects in a timely manner. Effectively, for 2009, new project development in the Spanish market has ceased, with development limited to deploying projects that already have an incentive reservation.[2]

We recommend that all applicants for a qualifying system be required to submit a reasonable deposit, proof of project viability (e.g. a signed customer contract and proof of site control) with their application. Applicants should also be required to comply with a rigorous deadline by which the system must be installed, as in the proposed rules pertaining to capacity reservation, timing and duration in OAR 860-084-0210.

- **VIR adjustment should be based on market conditions**

We propose different methods for adjusting the value of the VIR according to actual uptake in the relevant system size category. Each proposal aims to avoid the potential danger of suppressing price declines in renewable energy and risking immediate oversubscription (through a VIR that is too high) or inadequate development (through a VIR that is too low).

We recommend that for small-scale qualifying systems, applications may be submitted at any time during the pilot year until the annual capacity limit is fully deployed. In addition, we recommend that the Commission establish quarterly MW allocation limits. The Commission should review the VIR if the quarterly MW allocation limit is achieved. If the quarterly MW allocation limit is not achieved, the Commission should not reduce the VIR. If the quarterly MW allocation were achieved, the VIR reduction would be within the Commission's discretion, but in any case should be limited to no more than a 10% reduction from the previous VIR. Prospective system applicants should be notified of a VIR reduction at least 30 days before the VIR reduction becomes effective. The cumulative nameplate capacity of systems that have had applications accepted for pilot program participation should be made publicly available on a weekly basis.

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[2] See "Solar Fraud Could Eliminate Spanish Market" (December 15, 2008) http://www.greentechmedia.com/articles/read/solar-fraud-could-eliminate-spanish-market-5380/

For the majority of medium-scale systems, we recommend that the Commission establish MW capacity targets within each year of the pilot programs. Achievement of the MW capacity targets should trigger an automatic VIR reduction to a previously known and established level. *The VIR should only be reduced if the MW capacity target is achieved.* Prospective system applicants should be notified of a rate reduction when over 95% of the capacity target has been achieved and at least 10 days before the VIR reduction becomes effective. As above, VIR reductions should be limited to no more than 10% of a reduction from the previous VIR. The cumulative nameplate capacity of systems that have had applications accepted for pilot program participation – as well as the number and capacity of pending applications- should be made publicly available on at least a weekly basis, preferably more often than weekly.

For large-scale systems and a portion of medium-scale systems, the Commission should establish a competitive solicitation processes. In a December 15, 2009 Interoffice Memo to Lee Sparling and Maury Galbraith, Senior Assistant Attorney General Stephanie S. Andrus discussed possible limitations on the Commission's ability to establish prices for wholesale power sales that are transacted in interstate commerce. A significant benefit of a competitive solicitation process for administering the VIR is that it does not give rise to preemption concerns. As Ms. Andrus noted in her Interoffice Memo, the Commission could "(2) Require the IOUs to issue Requests for Proposals to pilot program participants for supply of energy". (Andrus memo at page 8.)

We recommend two annual Commission-approved Request for Proposals (RFP) processes, one for medium-scale systems and another for large-scale systems. The processes should include prioritization of proposals based on proposed VIRs and geographic diversity. Proposals should be required to provide relevant information and sufficient monetary deposits to demonstrate system viability, including a reasonable lump sum deposit based on a specific dollar value per kilowatt of the proposed system, a non-refundable application processing fee, and a guarantee of site control. Proposals could be for a single system or aggregated systems, as long as the cumulative nameplate capacity of any single proposal for the large-scale process was greater than 100 kW or less than or equal to 500 kW in size, and as long as any single proposal for the medium-scale process was greater than 10 kW or less than or equal to 100 kW in size.

All proposals, regardless of the proposals' VIR, should be considered in the RFP process. Active proposals that are aggregated systems should be prohibited from submitting applications as medium-scale or small-scale projects. (Unless and until FERC establishes rules waiving PURPA Qualifying Facility (QF) certification requirements for generators under 1 MW in size, winning proposals would need to register as a PURPA Qualifying Facility.)

The following chart summarizes our proposals:

	Rate Adjustment Basis	Rate Adjustment Amount	Rate Adjustment Direction	Rate Recipients
Small-Scale	VIR review upon achievement of quarterly MW allocation. Commission to announce new VIR rate at least 30 days in advance.	0% if quarterly MW allocation not reached; otherwise maximum 10% reduction	Level or reduced only	First come, first served until date certain
Majority of Medium-Scale	Pre-established VIR "steps" triggered by achievement of MW targets. Commission to announce when 95% of MW target has been reached and provide a 10-day window for new applications prior to the rate reduction.	Pre-established "steps" triggered by achievement of MW targets; maximum 10% reduction for each "step"	Level or reduced only	First come, first served until "step" occurs
Large-Scale and a Portion of Medium-Scale	Request for Proposals	Based on proposals received	Based proposals received	Winning proposals

V. Measuring Capacity

We agree with the proposed rule requiring the capacity of photovoltaic systems to be counted as the capacity on the alternating current side of the system's inverter (OAR 860-084-0160 and OAR 860-084-0040). We do not believe a conversion methodology is needed, as the capacity of any generating system can be measured as the maximum alternating current output.

VI. Establishing and Terminating Contracts

We generally agree with the proposed rules establishing and terminating contracts created for the pilot programs (OAR 860-084-0240). We also agree that qualifying systems are exempt from property taxes in accordance with ORS 307.175. In the case of those individuals and entities whose principal business activity is deemed not to be the production, transportation or distribution of energy, the qualifying systems would qualify for exemption from ad valorem taxation because they are "alternative energy systems," i.e., solar energy systems used for generating electrical energy. OAR 150-307.175(4). In the case of those individuals and entities whose principal business activity is deemed to be the production, transportation or distribution of energy, the qualifying systems ("alternative energy systems") would qualify for exemption to the extent the system is a net metering facility (ORS 757.300), or other system primarily designed to offset onsite electricity use. OAR 150-307.175(3).

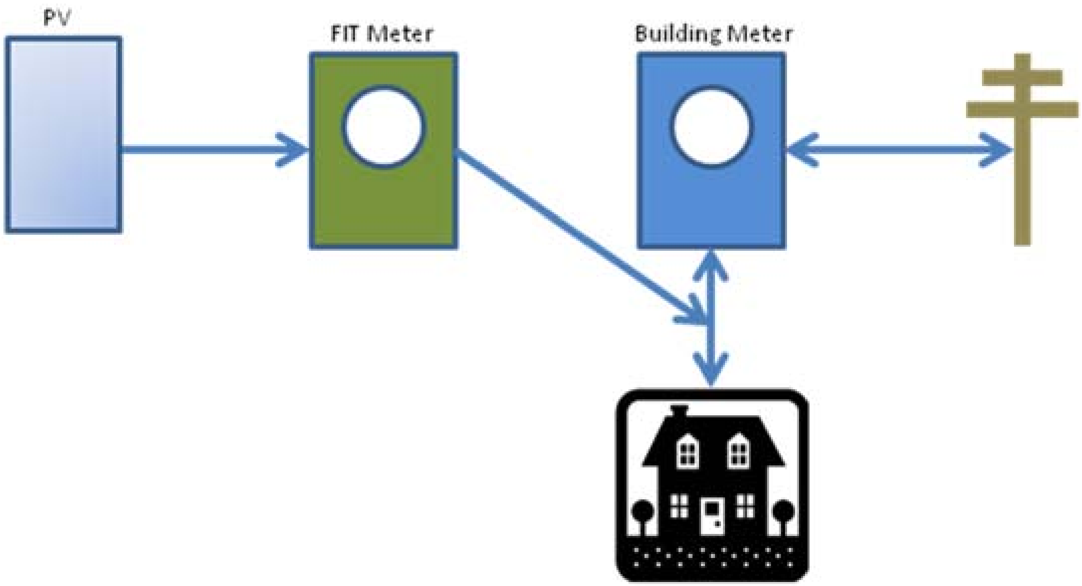
Alternative Proposal: Net Metering Plus VIR as an Opportunity to Avoid FERC Pre-Emption and Enhance Cost-Effectiveness

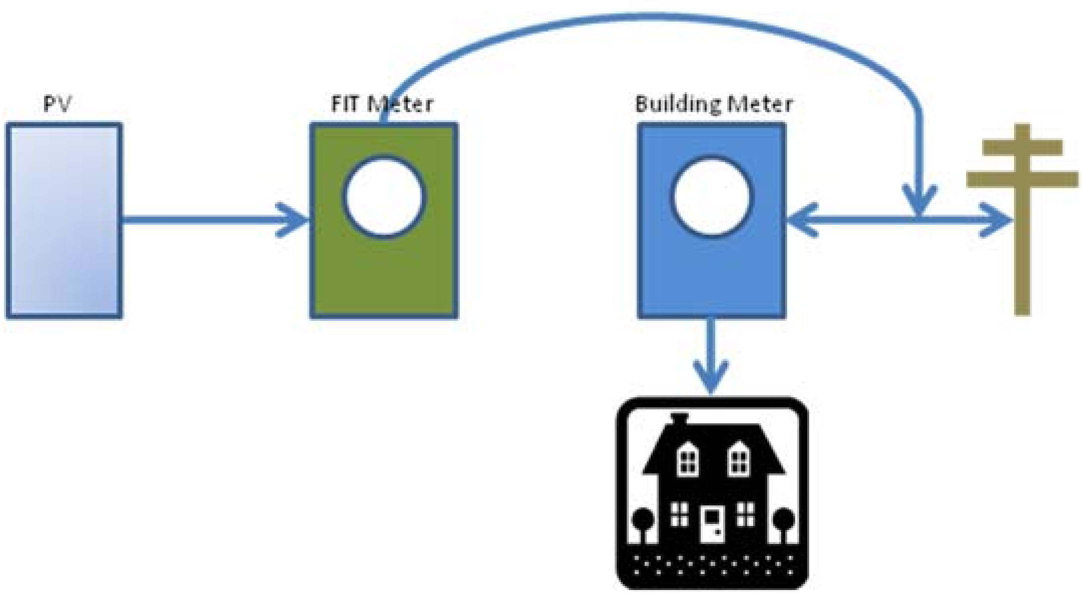
We recommend that all small-scale and a majority of medium-scale systems in the pilot programs should be a net metering plus VIR arrangement. While a connection point *after* customer load (feed-in tariff (FIT) only) is generally a feature of European FITs, the FIT connection point after customer load feature of European FITs is in large part due to the fact that net metering simply did not develop previous to FIT development in these countries.

A net metering plus VIR calculated as a complement to (not replacement for) customer retail savings is a valid alternative to a VIR only arrangement, and appears to be explicitly contemplated in legislation. Section 1(3)(b)(A) of HB 3039 requires that a qualifying system "meets the electric company's customer load service obligation as its primary purpose." HB 3039 does not specify the point at which the system is connected to the grid. In fact, the phrase "indirectly connects through the system of an electric company's retail electricity consumer" (Section 1(3)(b)(B) specifically contemplates a connection on the customer's side of the meter, as opposed to directly into the distribution system.

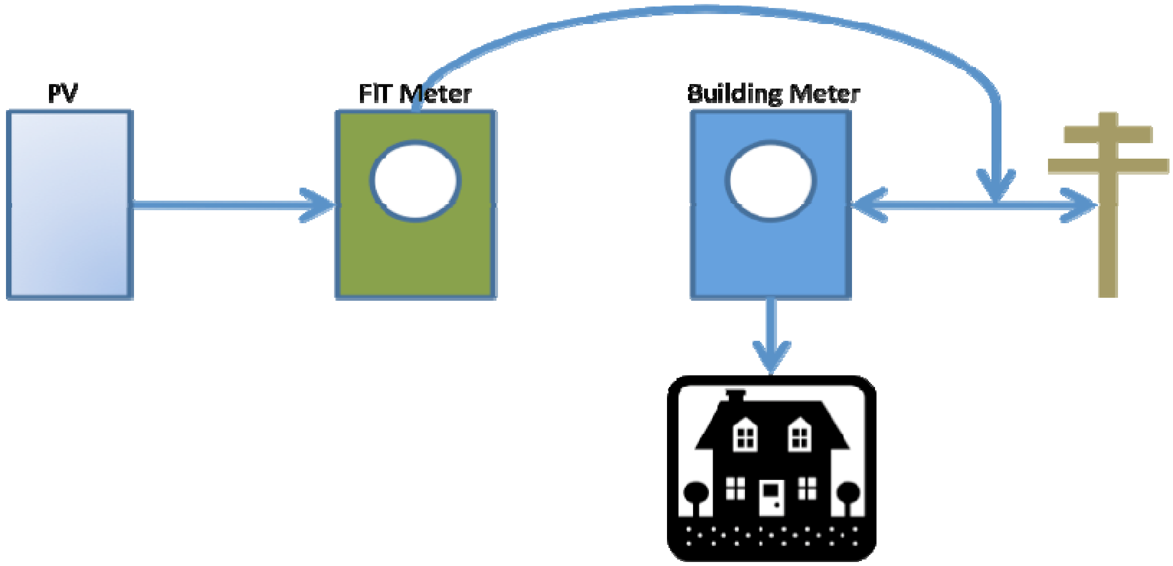
In this arrangement, customers would receive a (reduced) production payment for *all* kWh generated by their system, together with the retail savings associated with net metering. Or, as a diagram:

Net metering plus VIR:





VIR only:



There are some significant potential benefits associated with a net metering plus VIR. These benefits include:

- **Avoidance of potential FERC pre-emption**

A significant benefit of a net metering plus VIR structure for administering the pilot programs is that it does not give rise to preemption concerns. As Ms. Andrus noted in her December 15, 2009 Interoffice Memo, "FERC has concluded that net metering transactions in which a customer is credited by a public utility for energy generated by the customer and transmitted to a public utility is not a sale subject to FERC's jurisdiction, as long as the transactions do not result in a net sale over a reasonable period of time, such as a billing period. Andrus Memo at page 3. Administering the VIR and associated payments in conjunction with a net metering arrangement structures the VIR as a production-based incentive payment for energy used on-site as opposed to a payment for a wholesale power transaction. Accordingly, structuring the transaction in this manner avoids the preemption concerns addressed by Ms. Andrus that are associated with establishing prices for wholesale power transactions.

- **Similar customer economics**

Identical rates of customer return can and should be provided under a net metering plus VIR and VIR only arrangements. The net metering plus VIR would remain a fixed, long-term production payment for 100% of the solar production, providing the same investor certainty. An illustrative example:

Net metering plus VIR = 33 cents / kWh for 15 years; no customer savings from solar

VIR only = 8 cents customer retail savings / 15 years and 25 cents VIR / 15 years

- **Similar complexity of calculation**

Setting an initial VIR for either the net metering plus VIR or VIR only arrangement requires the consideration of a wide array of variables. These variables include solar irradiance, system installed cost, costs of capital and rates of return, operations and maintenance costs, and state and federal taxation. The proposed rules require the Commission to estimate a value of future energy savings in setting the VIR (OAR 860-084-0200)[3]. A customer contemplating a system with net metering plus VIR must also consider a similar variable. For these reasons both a net metering plus VIR and VIR only have a similar degree of complexity in VIR setting.

- **Increased customer participation**

If the pilot programs are not structured to allow for qualifying systems to interact with load onsite, system installations can be installed on customer facilities only at significantly increased cost to ratepayers as compared to simple large ground mounts on leased land. This is primarily because rooftop installations, which are imperfectly oriented and irregularly shaped, are generally more expensive in comparison to an equivalent ground-mounted system on a plot of leased land. A net metering plus VIR that interacts with onsite load compensates for these

[3] For an excellent review of the myriad of financial factors underlying a typical solar project, we refer the Commission to the National Renewable Energy Laboratory's interactive "Solar Advisor Model" at https://www.nrel.gov/analysis/sam/.

additional costs. This compensation is in the form of increased value for the generation through reduced distribution costs as opposed to compensation in the form of a higher incentive value.

- **Ratemaking efficiencies**

A net metering plus VIR allows solar developers or customers to naturally and automatically monetize the savings they produce on the electrical system, essentially "piggybacking" on the ratemaking procedures that establish distributed electricity rates, as opposed to a more elaborate exercise of reverse-engineering distribution savings values.

- **Improved Tax Efficiency**

In a net metering plus VIR arrangement, the customer receives a significant proportion of their economic benefit in the form of nontaxable energy savings within their "right to save". In contrast, in a VIR only arrangement, the customer must pay federal and state taxes on the full spectrum of revenues required to serve system economics. The following example, which is for illustrative purposes, uses an arbitrary VIR level and retail electricity savings to demonstrate the approximate magnitude of the savings associated with carrying no tax liability for generation serving onsite load. The combined effects of federal and state income tax efficiency is to make the required VIR rate for VIR only installations significantly higher than that required for net metering plus VIR installations, with a VIR only residential system requiring $0.57 per kWh to obtain similar financials to a net metering plus VIR residential system requiring $0.42 per kWh. Effects on commercial systems are less pronounced, since the pre-solar and post-solar electric costs of a commercial system are themselves tax-deductible.

	Residentially owned, VIR only, "low case"[4]	Commercially owned, VIR only, "low case"	Residentially owned, net metering plus VIR, "low case"	Commercially owned, net metering plus VIR, "low case"
Estimated VIR required per kWh (assuming all systems are property exempt)	**$0.66**	**$0.43**	**$0.50**	**$0.38**

Estimated commercial VIR increase required to support VIR only (vs. net metering plus VIR)	**13%**
Estimated residential VIR increase required to support VIR only (vs. net metering plus VIR)	**32%**

VII. Volumetric Incentive Rates

We agree with the proposed rules detailing how the VIR is set (OAR 860-084-0200) and codifying Commission authority to set and change the VIRs (OAR 860-084-0360).

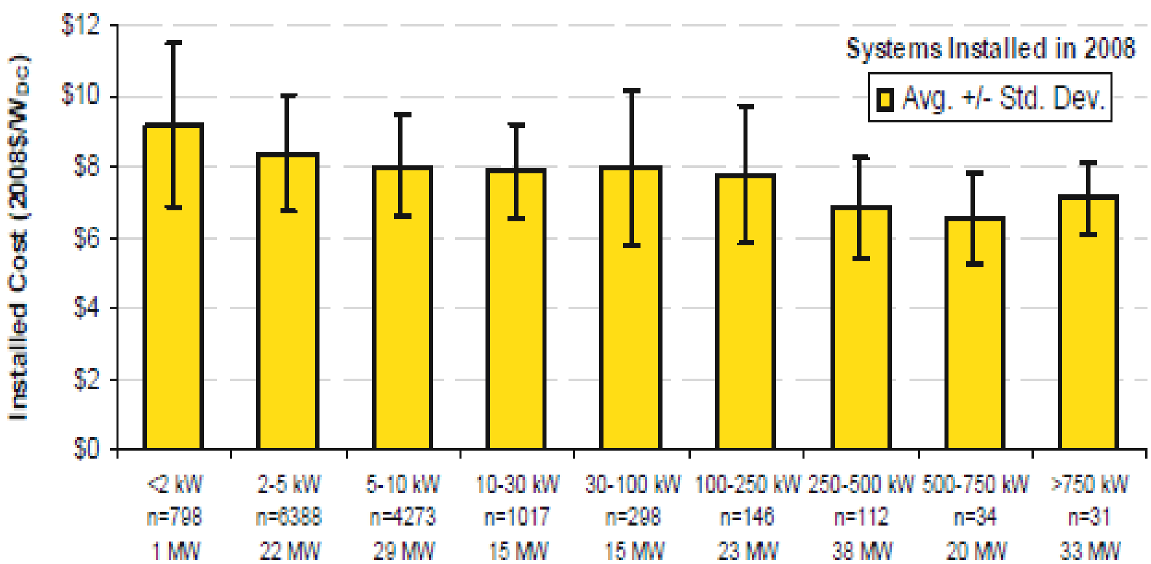
We recommend an additional stakeholder workshop to discuss VIRs. We are pleased that Staff has scheduled a VIR workshop and a workshop with the Commissioners on January 20th. Stakeholders have not had the opportunity to work with Staff to review and discuss a sample pro forma[5] and various inputs to that pro forma. While we understand the general assumptions that

[4] "Low Case" Assumptions: $6.00/Wp installed cost for commercial; $7.00/Wp installed cost for residential. 1330 MWh/MW/year production for residential; 1302 MWh/MW/yr production for commercial. Federal tax rates: 25% residential; 34% commercial. State income tax rates: 6.6% for both residential and commercial. 5 year accelerated depreciation for commercial. Commercial electricity costs for net metering are deducted as a business expense. Target 15-year IRR is 10% for commercial, 8% for residential. For both residential and commercial: 0.45% per year output degradation; $0.25 / Watt inverter replacement in project year 12; $5 / kW ($500 / acre) lease payment for land or space; and $25 / kW annual maintenance.

[5] We suggest using the National Renewable Energy Laboratory's Solar Advisor Model: www.nrel.gov/analysis/sam/. For calculation of underlying resource values, we also refer the Commission to E3's preliminary cost-effectiveness assessment of the California Solar Initiative (CS) for the California Public Utilities

Staff used to develop the proposed VIRs, additional time and discussion is needed to ensure that the initial VIRs for the pilot programs appropriately account for variations in local, state and federal taxes (and potential tax exemptions, tax credits and accelerated depreciation), financing costs, financing availability, geographic location and solar insolation.

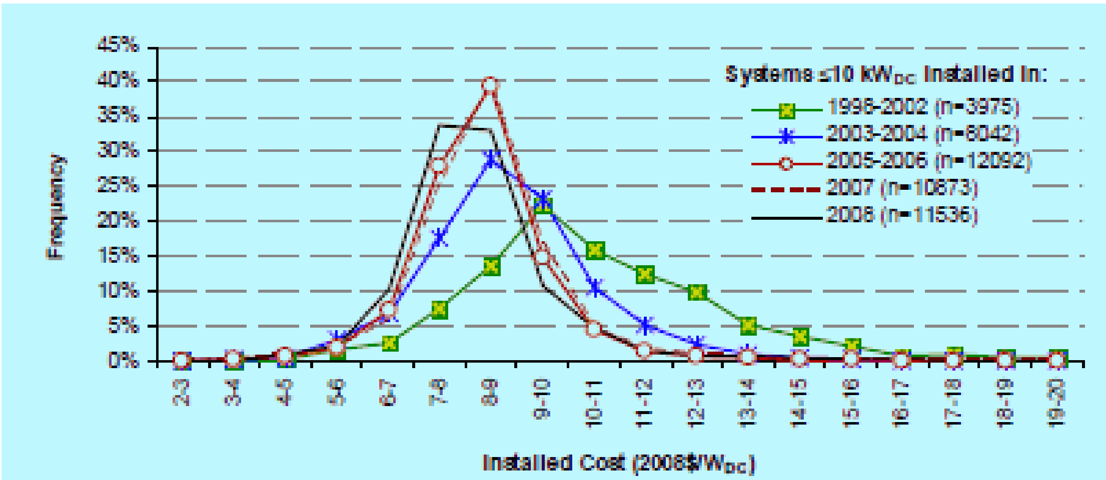
Even in the same geography, and with similar system sizes, solar systems have a large degree of diversity in system pricing. The following chart[6] illustrates the variation in installed costs for systems in 2008. Of particular note are the very large error bars – one standard deviation in solar system prices encompasses *several dollars per Watt* in installed system costs.

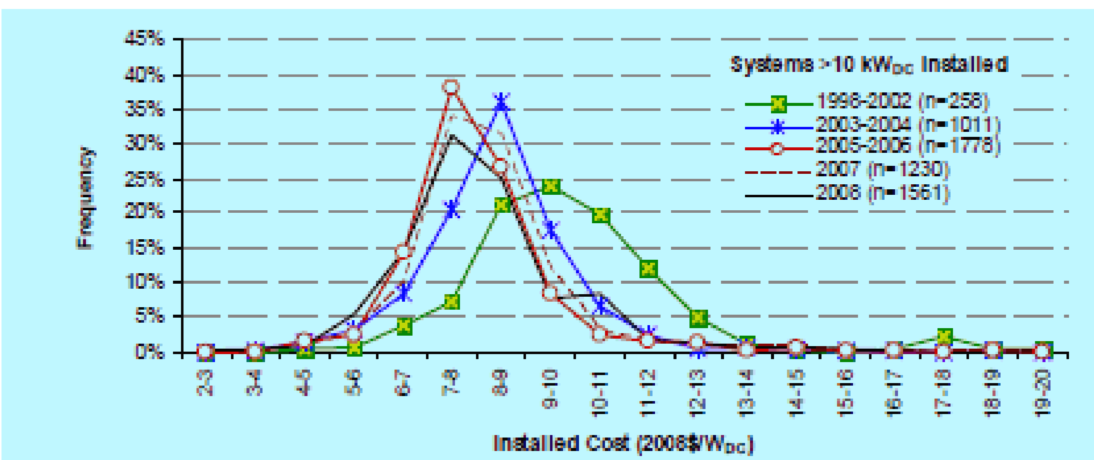


The same effect can be seen using another view; the graphs below present the "bell curves" of US solar installation prices, with small systems in the upper graph and systems >10 kW in the lower graph. Different color graphs represent different installation years.

Commission: http://www.ethree.com/CPUC_CSI.html, as well as the RW Beck "Distributed Renewable Energy Operating Impacts and Valuation" study recently completed by RW Beck for the Arizona Corporation Commission at http://www.aps.com/_files/solarRenewable/DistRenEnOpImpactsStudy.pdf.

[6] All charts are from "Tracking the Sun: The Installed Costs of Photovoltaics in the U.S. from 1998-2008", Lawrence Berkeley National Laboratories, http://eetd.lbl.gov/ea/ems/re-pubs.html. A less well-documented but more granular data source can be found at http://openpv.nrel.gov/visualization/index





We feel that this data represents several important "lessons learned" that Staff and the Commission should incorporate the following lessons learned when developing initial VIRs for pilot programs:

- **System prices decrease rapidly, but unpredictably**

In each year of the previous charts, the curve is significantly further to the left (i.e. less expensive) than it was the previous year. That is, a VIR that is correct at the beginning of any given year may be made wrong very quickly – very possibly faster than any non-automatic administrative process could respond.

- **"Average" system prices can be misleading**

Even within a single year and a single size category, systems have a broad range of prices. That is, since the 'bell curve' in the previous charts is so broad, an average price calculated to make the "most efficient" systems or the "average-priced" systems reach a given rate of return will likely only correctly apply to a small minority of systems.

- **Financing rates are highly variable**

The rate of return required by a homeowner investing for themselves is significantly different from the rate of return required by a commercial leasing or PPA provider providing them with a system, and both are very different from that required for a commercial "big box" store. Even in one neighborhood, individual tax brackets and credit ratings could very significantly affect pricing.

It is largely due to these effects that the history of attempts to predict the "perfect price" for performance-based renewable energy incentives, and to adjust this price at the "perfect time" is not encouraging. In Spain (post-2006), the Czech Republic (post-2008), Gainesville Florida and Vermont (both 2009), a dramatically high was followed by massive oversubscription and subsequent major uncertainty. In Spain (pre-2006), the Czech Republic (pre-2008) and Ontario (pre-2009, with one major project exception), the price was far too low, resulting in very limited project development. Germany's uncapped policy has permitted development to continue in a given annual period regardless of total annual expenditures.

Distributed solar development, which can involve hundreds or thousands of systems using a rapidly developing technology, is inherently unlike the development of an investment scenario for a more conventional regulated rate of return asset. Accordingly, policies that do not have the option of unlimited annual spending must focus on a price adjustment mechanism that automatically, but predictably reacts to the actual price of the resource – not an administrative approximation - using the following principles:

- **Initial VIRs should be set at levels sufficiently high enough to result in significant numbers of system installations today**
- **Future VIRs should reduce according to real-world market conditions, as established with the best market data that can be cost-effectively obtained**
- **VIR setting and reductions should be transparent and include sufficient notice to all prospective program participants**

Policy design instituting these "automatic digression" principles have been instituted in Spain (after the program's near-collapse) and have been proposed by leading German solar manufacturers as a means of addressing Germany's annual policy uncertainty around the EEG digression rate. They area also used in the Colorado, California, New Jersey and Arizona incentive schemes, which are among the most effective in the U.S.[7] These policies rely not on the *estimated* price and required rate of return of systems, but on the *actual* economics of the system, as reflected by the real-world behavior of customers and investors with viable qualifying systems.

Initial VIRs can be set in any number of ways, including a market-based mechanism such as a Request for Proposals (RFP) process or a conservative Commission estimation (perhaps a

[7] See for instance: http://www.xcelenergy.com/Colorado/Residential/RenewableEnergy/Solar_Rewards/Pages/CurrentPricing.aspx or http://www.csi-trigger.com

more transparent version of the approach of the straw proposal as established in the scheduled workshops). However, the transactional costs and transactional timeframes of participation in a market-based mechanism are significant. It is entirely possible and economic for a 500 kW system to compete in a simplified RFP. However, it is likely not possible for a 4 – 10 kW residential system to do so, and it would introduce significant bidding uncertainty into the sales process.

For all of these reasons we recommend that the Commission approve pilot programs that include a diversity of VIR setting and reduction mechanisms (as in Section IV and associated summary table). Our recommended mechanisms include a Commission-mediated quarterly MW allocation limits, VIR review and potential reduction for small-scale systems, a VIR reduction triggered by achievement of installed capacity targets for the majority of medium-scale systems, and a competitive solicitation for large-scale systems and a portion of medium-scale systems. We feel that these diverse mechanisms establish a workable balance between the long-term sustainability of an automatic price discovery mechanisms and the desire to keep transaction costs minimal and streamlined. Further, and importantly, this diversity of VIR setting mechanisms should permit the Commission to obtain useful pilot data on factors leading to each mechanisms' relative effectiveness.

VIII. Payments and Assignment of Payments

We agree with the proposed rules' establishment of how payments are derived and determined after the 15 year VIR contract period has ended (OAR 860-084-0360), the requirements of utility resource filings (OAR 860-084-0370), definitions for default and alternative processes (OAR 860-084-0250), definitions for qualifying third parties (OAR 860-084-0010 (11)) and determination of processes regarding changes (OAR 860-084-0140).

IX. Deployment of Program Capacity

We agree with the straw proposal recommendation for the Commission to decide a fraction of the 25 MW target for the pilot program be initially allocated to each electric company, proportional to their share of the 2008 Oregon total electric retail revenue of investor owned utilities. We also agree with the straw proposal recommendation for the Commission to direct each electric company to offer the fraction of its capacity allocation in each pilot year, and across size classes. Finally, we agree with the proposed rules establishing how the initial capacity allocation may be changed (OAR 860-084-0170), and defining pilot program years (OAR 860-084-0010 (10)).

We recommend that the Commission target deployment of 50% of the 25 MW of nameplate capacity per year over the first two years of the pilot programs. Further, to ensure a significant number of system installations in each of the system size categories (our recommendations regarding appropriate system size categories are in Section IV), we recommend the Commission set annual MW nameplate capacity targets for each system size category. Specifically, we recommend the Commission limit small-scale system deployment to no more than 3 MW of nameplate capacity per year, medium-scale system deployment to no more than 6.5 MW per year, and large-scale system deployment to no more than 3 MW per year. If any of the system size categories were not to achieve the MW nameplate capacity limit for that year, the excess capacity for that category should be rolled into the next year's MW capacity limit for the same size category. We also recommend that 1.5 MW of the 6.5 MW for medium-scale system deployment be reserved for a medium-scale Request for Proposal process as described in Section IV.

Our proposed capacity deployment schedule and annual MW capacity targets would result in approximately 300 – 1,000 small-scale system installations in per year, approximately 65 – 590 medium-scale system installations per year, and approximately 6 – 27 large-scale system installations per year. As a point of reference, the Energy Trust of Oregon-funded installations 384 small-scale systems (<10 kW), 64 medium-scale systems (10-100 kW) and 7 large-scale systems (100 kW) in 2009.

Alternative proposals – to utilize the pilot programs' allocations over a four-year period would result in an overall program significantly smaller than the existing incentive regimes, which would greatly impact growth and development of the solar industry in Oregon.

X. Rate Impact and Cost Recovery

We agree with the straw proposal's recommendation for the Commission not to impose an initial rate impact ceiling, pending program outcomes. We agree with the proposed rules allowing the Commission to establish a rate impact ceiling (OAR 860-084-0380), describing the requirements of utility filings on resource value (OAR 860-084-0370), and providing that the utilities may request recovery of prudently incurred costs (OAR 860-084-0390).

XII. Learning and Recommendations

We agree with the proposed rules establishing utility data collection for the pilots (OAR 860-084-0400 through 0430), except for the requirement in OAR-084-0430 (3) that would conceal total capacity deployed to date. This type of data would be critical to establishing pricing under many of the mechanisms we have proposed, and in general would seem to be a key metric of policy success and development.

We agree with the proposed rules that generate recommendations from the pilot programs in (OAR 860-084-0440 through 0450). In general, we agree with the proposed rules regarding data collection, reporting and decision-making (OAR 860-084-0210). However, we do not believe fees for capacity reservation should permissive based on the electric companies' request (as currently proposed in OAR 860-084-0210 (3)) but instead recommend that a reasonable fee for capacity reservation should be a requirement for all applications as a means of preserving the integrity of the program.

XIII. Pilot Year and Program Termination

Our alternative proposal described in Section IV requires significant revisions to the proposed rule regarding capacity availability (OAR 860-084-0220). Our proposed revisions to this portion of the rule are included in the Appendix. We agree with the proposed rules regarding the last capacity reservation application (OAR 860-084-0100 (2)), the process that describes capacity reallocation (OAR 860-084-0170), and the process that describes the end of the pilot programs (OAR 860-084-0010, OAR 860-084-0170 and OAR 860-084-0150).

DATED this 14th day of January 2010.

ESLER, STEPHENS & BUCKLEY

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OREGON ADMINISTRATIVE RULES
CHAPTER 860, DIVISION 084 – PUBLIC UTILITY COMMISSION
DIVISION 084
SOLAR PHOTOVOLTAIC PROGRAMS

860-084-0000
Scope and Applicability of Solar Photovoltaic Programs

(1) OAR 860-084-0020 through 860-084-0080 ("the Solar Photovoltaic Capacity Standard") govern implementation of programs requiring electric company installation of solar photovoltaic capacity.

(2) OAR 860-084-0100 through 860-084-0450 (the "Solar Photovoltaic Pilot Programs") govern implementation of pilot programs to demonstrate the use and effectiveness of volumetric incentive rates and payments for electricity delivered from solar photovoltaic energy systems.

(3) For good cause shown, a person may request the Commission waive any of the rules contained in Division 084.

Stat Auth: 2009 OR Laws Ch. 748
Stats. Implemented: 2009 OR Laws Ch. 748
Hist: NEW

860-084-0010
Definitions for Solar Photovoltaic Capacity Standard and Pilot Programs

(1) "Annual resource value" means the resource value of the energy delivered in the year that it is generated.

(2) "Contracted system" means an eligible system under contract in the solar photovoltaic pilot program.

(3) "Date of Enrollment" means the date when a solar photovoltaic system is on-line (begins providing energy to the electric company's electrical system).

(4) "Electric company" has the meaning given that term in ORS 757.600.

(5) "Eligible system" means a qualifying system that meets the requirements of OAR 860-084-0120.

(6) **"System components"** ~~"Equipment package"~~ means a group of components connecting an electric generator with an electric distribution system, and includes all interface equipment including switchgear, inverters, or other interface devices. **System components** ~~An equipment package~~ may include an integrated generator or electric production source.

(7) "Nameplate capacity" means the maximum rated output of a solar photovoltaic system under **Standard Test Conditions. "Standard Test Conditions" are an irradiance level of 1000 W/ m², with the reference air mass 1, 5 solar spectral irradiance distribution and cell or module junction temperature of 25°C.** ~~specific conditions designated by the manufacturer~~.

(8) "Eligible participant" or "participant" means a retail electricity consumer receiving service at the property where the solar photovoltaic energy system will be installed.

(9) "IEEE standards" means the standards published in the 2003 edition of the Institute of Electrical and Electronics Engineers (IEEE) Standard 1547, entitled “Interconnecting Distributed Resources with Electric Power Systems,” approved by the IEEE SA Standards Board on June 12, 2003, and in the 2005 edition of the IEEE Standard 1547.1, entitled “IEEE Standard Conformance Test Procedures for Equipment Interconnecting Distributed Resources with Electric Power Systems,” approved by the IEEE SA Standards Board on June 9, 2005 **or their successors.**

(10) “Pilot year” means each twelve-month period of the solar photovoltaic pilot program beginning on April 1. Year one of the pilot program is April 1, 2010 to March 31, 2011; year two of the pilot is April 1, 2011 to March 31, 2012, etc.

(11) “Qualifying third party” or “third party” means third party authorized, by the retail electricity consumer, to be assigned payments by the electric company under the standard contract. An electric company or its affiliate is not a qualifying third party. Qualifying third parties include, but are not limited to:

(a) A lender providing up front financing to a retail electricity consumer,

(b) A company or individual who enters into a financial agreement with a retail electricity consumer to own and operate a solar photovoltaic energy system on behalf of the retail electricity consumer in return for compensation,

(c) A company or individual who contracts with the retail electricity consumer to locate a solar photovoltaic system on property owned by the retail electricity consumer, or

(d) Any party identified by the retail electricity consumer to receive payments that the electric company is obligated to pay to the retail electricity consumer.

(12) “Reservation expiration date” means the date that a capacity reservation expires. A retail electricity consumer must newly apply for a capacity reservation, once the reservation expires.

(13) “Reservation start date” means **the date the retail electricity consumer or eligible system owner is allocated capacity through a capacity reservation process.**

~~(a) For smaller size systems, the date the electric company receives both a capacity reservation application and an application for interconnection, or~~

~~(b) For medium and large systems, the date the consumer is allocated capacity through an annual capacity reservation process.~~

The reservation start date starts the clock for the time to interconnection agreement.

(14) “Reserved system” means an eligible system that has been granted a capacity reservation in the solar photovoltaic pilot program.

(15) “Retail electricity consumer” means a consumer who is a direct customer of the electric company and is the end user of electricity for specific purposes, such as heating, lighting or operating equipment.

(16) “Resource value” means the portion of the volumetric incentive rate that represents the fully loaded avoided cost of the energy provided to the electric company. This value comprises the avoided cost of comparable generation (including avoided fuel volatility, minus the costs of firming and shaping the electricity generated from solar photovoltaic energy systems, **but including any offsetting capacity or ancillary service benefits of solar energy**), the avoided cost of transmission and distribution in delivering energy from other generation

sources, and a value equivalent to the renewable energy **certificate** value of the solar photovoltaic energy.

~~(17) "System requirements" means the input electricity required to allow the solar photovoltaic energy system to operate, sometimes referred to as the parasitic load. System requirements do not include energy used on site by the customer for other purposes.~~

(18) "Volumetric incentive payments" or "payments" means the monthly amount that an electric company pays to an eligible participant in the solar photovoltaic pilot program.

(19) "Volumetric incentive rate" means the rate per kilowatt-hour paid by an electric company to a retail electricity consumer ~~providing~~ **using** energy from a contracted system. This rate comprises the underlying resource value and the solar photovoltaic pilot subsidy.

(20) "Time to interconnection agreement" means the time between the reservation start date and the date an eligible participant signs an interconnection agreement.

(21) "Solar pilot capacity limit" means the maximum installed capacity that each electric company may contract during the pilot program.

Stat Auth: 2009 OR Laws Ch. 748

Stats. Implemented: 2009 OR Laws Ch. 748

Hist: NEW

Solar Photovoltaic Capacity Standard

860-084-0020

Solar Photovoltaic Capacity Standard

On or before January 1, 2020, each electric company must own, or contract to purchase the capacity and output of, qualifying solar photovoltaic energy systems to achieve, or exceed, the following minimum solar photovoltaic capacity standards:

(1) Portland General Electric: 11.8 megawatts

(2) Pacific Power: 7.9 megawatts

(3) Idaho Power Company: 0.3 megawatts

Stat Auth: 2009 OR Laws Ch. 748

Stats. Implemented: 2009 OR Laws Ch. 748

Hist: NEW

860-084-0030

Qualifying Systems under the Solar Photovoltaic Capacity Standard

Individual solar photovoltaic energy systems used to comply with the solar photovoltaic capacity standards specified in OAR 860-084-0020 must:

(1) Meet the electric company's customer load service obligation;

(2) Directly connect to an electric company's electrical system within Oregon, or indirectly connect to a third party electrical system within Oregon;

(3) Have meters or other devices in place to monitor and measure the quantity of energy generated;

(4) Meet the siting, design, interconnection, installation, and electric output standards and codes required by the laws of Oregon; and

(5) Have a nameplate generating capacity greater than or equal to 500 kilowatts and less than or equal to 5 megawatts.

Stat Auth: 2009 OR Laws Ch. 748

Stats. Implemented: 2009 OR Laws Ch. 748

Hist: NEW

860-084-0040

Measurement of Capacity under Solar Capacity Standard

(1) ~~Except as provided in section (3) of this rule,~~ The capacity of solar photovoltaic energy systems used to satisfy the requirements of OAR 860-084-0020 must be measured on the alternating current side of the system's inverter.

~~(2) Each electric company must follow Commission established guidelines when converting nameplate capacity ratings reported by manufacturers in terms of direct current **Watts** watts under standard test conditions to an alternating current rating in **Watts** watts to account for inverter and other system component losses and to account for the effect of normal operating temperature on solar module output.~~

~~(3)~~ (2) For solar photovoltaic energy systems that do not use an inverter, the capacity must be measured in terms of the nameplate capacity rating reported by the manufacturer in direct current **Watts** ~~watts~~, under **Standard Test Conditions**.

Stat Auth: 2009 OR Laws Ch. 748

Stats. Implemented: 2009 OR Laws Ch. 748

Hist: NEW

860-084-0050

Compliance Report

(1) On or before February 1, 2020, each electric company must file a report with the Commission demonstrating compliance, or explaining in detail its failure to comply, with the solar photovoltaic capacity standards specified in OAR 860-084-0020.

(2) The report in section (1) of this rule must include the following information associated with each solar photovoltaic energy system:

(a) The name of the facility;

(b) The location of the facility;

(c) The in-service date of the facility;

(d) The manufacturer's nameplate capacity rating;

(e) The electric company's capacity rating on the alternating current side of the system's inverter;

(f) The signing date of any associated power purchase agreement;

(g) The contracted capacity and output delivery period of any associated power purchase agreement

Stat Auth: 2009 OR Laws Ch. 748

Stats. Implemented: 2009 OR Laws Ch. 748

Hist: NEW

860-084-0060
Cost Recovery

An electric company may request recovery of its prudently incurred costs to comply with the solar photovoltaic capacity standard specified in OAR 860-084-0020 in an automatic adjustment clause proceeding filed at the Commission pursuant to ORS 469A.120.

Stat Auth: 2009 OR Laws Ch. 748

Stats. Implemented: 2009 OR Laws Ch. 748

Hist: NEW

860-084-0070
Renewable Energy Certificates and Compliance with the Renewable Portfolio Standards

(1) Except as provided in section (2) of this rule, each renewable energy certificate associated with the electricity produced by solar photovoltaic energy systems used to achieve, or exceed, the minimum solar photovoltaic capacity standards specified in OAR 860-084-0020 may be used to comply with the renewable portfolio standards established under ORS 469A.005 to ORS 469A.120.

(2) Each renewable energy certificate associated with the electricity produced by solar photovoltaic energy systems may be used, or counted, twice to comply with the renewable portfolio standards established under ORS 469A.005 to ORS 469A.120, if solar photovoltaic energy systems:

(a) First become operational before January 1, 2016,

(b) Are installed in Oregon, and

(c) Are within the solar photovoltaic capacity standards specified in OAR 860-084-0020.

(3) Renewable energy certificates used pursuant to sections (1) and (2) of this rule must comply with the standards of OAR 860-083-0050.

Stat Auth: 2009 OR Laws Ch. 748

Stats. Implemented: 2009 OR Laws Ch. 748

Hist: NEW

860-084-0080
Implementation Plans

Each electric company must incorporate its plan to achieve, or exceed, the minimum solar photovoltaic capacity standards specified in OAR 860-084-0020 into its renewable portfolio standard implementation plans filed pursuant to OAR-083-0400.

Stat Auth: 2009 OR Laws Ch. 748

Stats. Implemented: 2009 OR Laws Ch. 748

Hist: NEW

Solar Photovoltaic Pilot Programs

860-084-0100

Solar Photovoltaic Pilot Programs

(1) Prior to April 1, 2010, each electric company must establish a pilot program to demonstrate the use and effectiveness of volumetric incentive rates and payments for electricity delivered from qualifying solar photovoltaic energy systems.

(2) Capacity reservations in the solar photovoltaic pilot programs will be accepted from April 1, 2010, through March 31, 2015, or until a total installed solar photovoltaic pilot program capacity limit of 25 megawatts is reached, whichever comes first, and subject to any limitations on participation approved by the Commission, including customer class rate impacts.

Stat Auth: 2009 OR Laws Ch. 748

Stats. Implemented: 2009 OR Laws Ch. 748

Hist: NEW

860-084-0110

Qualifying Systems for the Solar Photovoltaic Pilot Programs

Individual solar photovoltaic energy systems qualifying for the Solar Photovoltaic Pilot Programs in OAR 860-084-0100 must:

(1) Meet the electric company's customer load service obligation;

(2) **Indirectly** ~~Directly~~ connect to an electric company's electrical system within Oregon, or indirectly connect to a third party electrical system within Oregon;

(3) Have meters or other devices in place to monitor and measure the quantity of energy generated;

(4) Meet the design, interconnection, installation, and electric output standards and codes required by OAR 860-084-0260;

(5) Meet the siting requirements defined in OAR 860-084-0120 and OAR 860-084-0130(3);

(6) Meet Commission established requirements for quality and reliability; and

(7) Have a nameplate generating capacity less than or equal to 500 kilowatts.

Stat Auth: 2009 OR Laws Ch. 748

Stats. Implemented: 2009 OR Laws Ch. 748

Hist: NEW

860-084-0120

Systems Eligible for Enrollment in Pilot Programs

(1) Individual solar photovoltaic energy systems eligible for the Solar Photovoltaic Pilot Programs in OAR 860-084-0100 must be:

(a) A qualifying system, as established in OAR 860-084-0110;

(b) Permanently installed in the State of Oregon by a retail electricity consumer of the electric company;

(c) Installed in the service territory of the electric company;

(d) Installed after April 1, 2010;
(e) Financed without expenditures under ORS 757.612 (3)(b)(B) or tax credits under ORS 469.160 or ORS 469.185 to 469.225; and
(f) Certified by the **retail** ~~residential~~ electric consumer as constructed from new components (modules, inverter, batteries, mounting hardware, etc.).

(2) Systems that are located outside of the service territory of the electric company are not eligible for enrollment in the electric company's pilot programs.

(3) Contracted systems that are uninstalled before the end of the contract term are not eligible for subsequent volumetric incentive rates, other feed-in tariffs, or pilot programs during the remainder of the contract term; and these systems cannot be reinstalled for the purposes of entering a new contract under any solar photovoltaic pilot program, volumetric incentive or other feed-in tariff program in the service territory of any electric company in the State of Oregon, except that a contracted system may be uninstalled and reinstalled at another location under the same contract under the conditions set forth in OAR 860-084-0280.

(4) Retail electricity consumers submitting applications for a 500 kilowatt project are not eligible to reserve capacity in the solar photovoltaic pilot program if ~~this~~ **the same** project is also competing for a purchased power agreement under the Solar Capacity Standard.

Stat Auth: 2009 OR Laws Ch. 748

Stats. Implemented: 2009 OR Laws Ch. 748

Hist: NEW

860-084-0130
Ownership and Installation

(1) An electric company must contract **to provide an incentive** for solar photovoltaic energy generated from eligible systems. **The contract may be between the electric company and the system owner or between the electric company and the retail electricity customer.** ~~installed by retail electricity consumers of the electric company.~~

(2) Eligible systems must be installed on the same property as the property where the retail electricity consumer buys electricity from the electric company, with the eligible system directly connected into the distribution feeder that services the consumer at the property or indirectly connected through the system of an electric company's retail customer or the electric system of a third party that is not an electric company's retail electricity consumer but whose system is located within this state.

(3) A retail electricity consumer must be allowed to transfer their existing contract to another **eligible** retail electricity consumer ~~eligible to contract with the electric company~~ under the pilot program.

(4) Eligible systems may be owned, operated, or owned and operated by qualifying third parties, as **where the system is** ~~given below~~:

(a) Owned by a qualifying third party as part of a loan agreement, or

(b) Owned and operated by a qualifying third party on behalf of the retail electricity consumer, or

(c) Owned and operated by qualifying third parties, or

(d) Operated by third parties on behalf of the retail electricity consumer.

(5) Ownership of Renewable Energy Certificates:

(a) The electric company receiving energy from solar photovoltaic energy systems meeting the requirements of OAR 860-084-0120, must receive 100 percent of the renewable energy certificates created through the generation of energy ~~contracted to the electric company~~ by these systems.

~~(b) Retail electricity consumers may retain renewable energy certificates created through the generation of energy used to supply system requirements.~~

Stat Auth: 2009 OR Laws Ch. 748

Stats. Implemented: 2009 OR Laws Ch. 748

Hist: NEW

860-084-0140

Assignment of Payments

(1) Electric companies must enable retail electricity consumers to assign payments to a qualifying third party under standard contracts that comply with Commission guidelines.

(2) Electric companies may charge a reasonable fee for the assignment of payments, at the time that the standard contract is assigned. Electric companies may charge for changes to assignment of payments over the contract term.

Stat Auth: 2009 OR Laws Ch. 748

Stats. Implemented: 2009 OR Laws Ch. 748

Hist: NEW

860-084-0150

Solar Photovoltaic Pilot Capacity Limit

(1) Pilot programs close to new capacity reservations on March 31, 2015, or when the cumulative capacity of contracted systems in pilot programs reaches 25 megawtts of nameplate capacity, whichever is earlier.

(2) Power that qualifies against this capacity limit is measured as the sum of power generated on the alternating current side of system inverters across all contracted systems.

Stat Auth: 2009 OR Laws Ch. 748

Stats. Implemented: 2009 OR Laws Ch. 748

Hist: NEW

860-084-0160

Measurement of Capacity under the Solar Photovoltaic Pilot Program

(1) ~~Except as provided in section (3) of this rule,~~ The capacity of solar photovoltaic energy systems used to satisfy the requirements of OAR 860-084-0150 must be measured on the alternating current side of the system's inverter.

~~(2) The Commission will establish guidelines for electric companies to follow when converting nameplate capacity ratings reported by manufacturers in terms of direct current watts under standard test conditions to an alternating current rating in watts to account for inverter and other system component losses and to account for the effect of normal operating temperature on solar module output.~~

Stat Auth: 2009 OR Laws Ch. 748

Stats. Implemented: 2009 OR Laws Ch. 748

Hist: NEW

860-084-0170
Distributing Solar Photovoltaic Pilot Capacity by Electric Company

(1) Each electric company will receive a share of the total solar photovoltaic pilot program capacity, given in OAR 860-084-0100(2), as established by Commission Order.

(2) An electric company's solar photovoltaic pilot program ends when the company reaches 100 percent of its solar photovoltaic pilot capacity limit.

(3) The Commission may consider requests to adjust each electric company's solar photovoltaic pilot capacity limit by changing the allocation of the total solar photovoltaic pilot program capacity from those established at pilot program initiation.

Stat Auth: 2009 OR Laws Ch. 748

Stats. Implemented: 2009 OR Laws Ch. 748

Hist: NEW

860-084-0180
Distributing Electric Company Capacity Limit by Pilot Year

(1) Each electric company must allocate a percentage of its total pilot capacity limit, as established in OAR 860-084-0170 for reservation in each of the pilot years; this annual allocation percentage will be established by Commission Order.

(2) The Commission may consider requests to adjust the annual allocation percentage for any electric company.

Stat Auth: 2009 OR Laws Ch. 748

Stats. Implemented: 2009 OR Laws Ch. 748

Hist: NEW

860-084-0190
Distributing Capacity Limit by System Size

(1) A solar photovoltaic system capacity is the total capacity contracted by a single retail electricity consumer within a Commission defined area.

(2) Three size classes of qualifying systems are established and defined by a range of nameplate capacity; the Commission may modify these capacity ranges, as required.

(a) **Small-scale** ~~Smaller~~ systems have a nameplate capacity of **less than or equal to** 10 kilowatts ~~or less~~;

(b) **Medium-scale** systems have nameplate capacities **greater** ~~larger~~ than 10 kilowatts and **less than or equal to** ~~up to~~ 100 kilowatts; and

(c) **Large-scale** systems have a nameplate capacity greater than 100 kilowatts and **less than or equal to** ~~up to~~ 500 kilowatts.

(3) **Smaller-scale systems have a nameplate capacity of less than or equal to 100 kilowatts.** ~~Smaller~~ **Smaller-scale** systems must be targeted to **attain a goal of 75 percent of the energy generated within each electric companies' allowed pilot capacity limit,** ~~generate up to 75 percent of the energy delivered to the electric companies under the solar PV pilot program,~~ unless otherwise directed by the Commission.

(4) Distributing Capacity to ~~Smaller~~ Systems: Each year, beginning April 1, 2010, an electric company must allocate a percentage of its annual pilot capacity allocation, established as in OAR 860-084-0180, for reservation to retail electricity consumers installing **small-scale, medium-scale and large-scale** ~~smaller~~ systems; ~~this percentage~~ **these percentages for small-scale, medium-scale and large-scale** systems will be established by Commission Order. The Commission may change **these percentages** ~~this percentage~~ over the pilot program.

~~a) Retail electricity consumers may reserve pilot program capacity at any time during the pilot year until the annual capacity limit is fully deployed.~~

~~b) An electric company with less than one megawatt of total allocation must allocate 100 percent of its solar photovoltaic capacity limit to retail electricity consumers installing smaller systems.~~

~~(5) Distributing Capacity to Medium and Large Systems: Each year, beginning April 1, 2010, an electric company must offer a percentage of its annual pilot capacity allocation, established as in OAR 860-084-0180, for reservation by retail electricity consumers installing medium or large size systems; the percentage allocated to medium capacity systems and the percentage allocated to large capacity systems will be established by Commission Order. The Commission may change these percentages over the pilot program.~~

~~a) Each electric company must receive applications for medium and large systems during the month of April of each year.~~

b) If capacity remains available in any ~~either~~ size class after reservations are made for all consumers whose applications meet established criteria, the electric company must continue to solicit applications and make capacity reservations, on a first-come, first-served basis ~~over the pilot year,~~ until all capacity is reserved.

~~c) If applications received during the month of April over-subscribe available capacity, capacity must be awarded to retail electricity consumers whose applications meet established criteria, by random drawing, until the annual capacity is fully allocated. Drawings must be carried out according to processes that comply with Commission guidelines.~~

~~(6) A retail electricity consumer may reserve capacity in the pilot program for up to five eligible systems.~~

Stat Auth: 2009 OR Laws Ch. 748

Stats. Implemented: 2009 OR Laws Ch. 748

Hist: NEW

860-084-0200

Capacity Reservation, Timing and Volumetric Incentive Rates

Reserved systems are eligible for the volumetric incentive rate in place at the time of their capacity reservation. Capacity reservation applications or standard contracts provided to retail electricity consumers at the time of capacity reservation must communicate the volumetric incentive rate that the retail electricity consumer is eligible to receive, based on their capacity reservation date.

Stat Auth: 2009 OR Laws Ch. 748

Stats. Implemented: 2009 OR Laws Ch. 748

Hist: NEW

860-084-0210

Capacity Reservation, Timing and Duration

(1) The capacity reservation for a reserved system expires as follows:

(a) For **small-scale** ~~smaller~~ systems, a reservation expires twelve months from the reservation start date.

(b) For **medium-scale and large-scale** systems, a reservation expires six months from the date that an interconnection agreement is signed or twelve months from the reservation start date, whichever is longer. ~~A four month extension may be granted if the majority of system components have been purchased and installation is underway, with work contracted for completion in the four-month window.~~

(2) Electric companies must collect data on time to interconnection agreement and carry out pilot program satisfaction surveys so as to be able to improve capacity reservation and interconnection processes over the pilot program, as required. Data collection and surveys must particularly explain and recommend or implement changes to processes that result in:

(a) Interconnection agreements that have not been successfully negotiated between the electricity company and the retail electricity consumer within a six month window after an application for interconnection has been filed, or

(b) Retail electricity consumers that have reserved capacity under the pilot programs, whose capacity reservations expire before solar photovoltaic energy systems are installed.

(3) Electric companies may request that the Commission impose fees for capacity reservation applications, based on analysis of this data.

Stat Auth: 2009 OR Laws Ch. 748

Stats. Implemented: 2009 OR Laws Ch. 748

Hist: NEW

860-084-0220

Capacity Availability

(1) Each electric company must announce the available capacity for the upcoming pilot year, no later than February 1 of each year. Each company must announce when the capacity allocation for the year is fully reserved.

(2) Capacity reserved for **small-scale** ~~smaller~~ systems that is not reserved in a pilot year must be added to the available capacity for **small-scale** ~~smaller~~ systems in the next pilot year;

capacity reserved for **medium-scale and large-scale** systems must be added to the available capacity for **medium-scale and large-scale** systems, **respectively,** in the next pilot year, unless otherwise directed by the Commission.

(3) In January 2013, or at a time otherwise determined by Commission Order, the remaining pilot capacity may be reallocated. Unless otherwise directed by the Commission, this reallocation may redistribute the remaining pilot program capacity so that 75 percent of the energy generated is generated from ~~smaller~~ **smaller-scale** systems at the time the pilot program reaches 25 megawatts of alternating current.

Stat Auth: 2009 OR Laws Ch. 748
Stats. Implemented: 2009 OR Laws Ch. 748
Hist: NEW

860-084-0230
Application for Capacity Reservation

(1) The electric company must establish, in compliance with Commission Order, a capacity application process for **small-scale** ~~smaller~~, **medium-scale and large-scale** capacity systems. The electric company must provide instruction to enable retail electricity consumers to generate capacity applications that meet the established criteria referenced in OAR 860-084-0280.

(2) Retail electricity consumers must simultaneously file an application for capacity reservation, an application for interconnection, and any required application fees.

(3) The capacity reservation application must require that retail electricity consumers certify that they have read and understand the standard contract established under the pilot program. Standard contract forms must be provided to retail electricity consumers as part of the application process.

Stat Auth: 2009 OR Laws Ch. 748
Stats. Implemented: 2009 OR Laws Ch. 748
Hist: NEW

860-084-0240
Standard Contracts

(1) Each electric company must file, for Commission approval, a standard, 15-year contract.

(a) This contract establishes a purchase agreement; the electric company contracts with participating retail electricity consumers to ~~purchase~~ **provide a volumetric incentive rate** for 100 percent of the kilowatt-hours generated~~, net of system requirements,~~ from eligible solar photovoltaic systems installed in the service territory of the purchasing electric company, at the applicable volumetric incentive rates approved by the Commission.

(b) Contracts, under the solar photovoltaic pilot programs, may only be issued to retail electricity consumers of the electric company eligible to participate in the pilot programs.

(2) The standard contract must allow for three options at normal termination of the 15 year contract:

(a) Retail electricity consumers may continue generation, under the existing contract, in return for payments that are based on the annual resource value, or

(b)Retail electricity consumers may uninstall their contracted system, or

(c) Retail electricity consumers may discontinue generation under the pilot program and apply to continue generation under volumetric incentive rate or net metering programs then in place.

(3) Standard Contracts must include at least the following elements:

(a) Name and address of the retail electricity consumer and the installation address of the eligible system.

(b) Volumetric incentive rate. The standard contract must be based on the volumetric incentive rate in place at the time of the capacity reservation for the retail electricity consumer.

(c) Contract term and termination option. Each standard contract must include a date of initiation and a date of contract expiration. The default termination option must be continuation of the contract in return for payments that are based on the resource value of power *g*enerated, unless otherwise selected by the customer.

(d) Certification of compliance. Each standard contract must include a section to record retail electricity consumer certifications that:

(A) No investor in the qualifying system has accepted or will accept incentives from the Energy Trust of Oregon or Oregon state residential or business tax credits for the qualifying system covered by the contract, and

(B) The system **and its individual components are new and have not been previously installed**. ~~is a new system.~~

(e) Agreement to release information about participation. Each retail electricity consumer must sign a release that allows the electric company to release lists of all participants in the pilot programs to the Oregon Department of Revenue, the Oregon Department of Energy, the Public Utility Commission, and the Energy Trust of Oregon. The standard contract must contain descriptions of the confidentiality requirements that those receiving this information must follow.

(f) Agreement to participate. Each standard contract must require a retail electricity consumer agreement that continued eligibility for the volumetric incentive rate pilot program requires the pilot participant to complete up to three surveys on the effectiveness of the pilot programs. The retail electricity consumer must also sign a release allowing the electric company to release this information to the Public Utility Commission and the Energy Trust of Oregon.

(g) Preferred payment option. Each standard contract must specify whether the retail electricity consumer elects to be paid monthly through direct payment or elects that the payment and billing be aggregated on a single bill. The default payment method must be aggregation on a single bill.

(h) Assignment of payment. Each standard contract must allow a retail electricity consumer to assign payments to a qualifying third party.

(i) Transfer of contract. Each standard contract must allow the transfer of an existing retail electricity consumer's contract under the pilot program to another retail electricity consumer eligible to receive payments from the electric company under the pilot program.

(j) Disclosure that payments are taxable as income, under Oregon and Federal Tax law, and that an eligible system is not subject to property tax in the State of Oregon.

Stat Auth: 2009 OR Laws Ch. 748

Stats. Implemented: 2009 OR Laws Ch. 748

Hist: NEW

860-084-0250

Billing and Payment Requirements

The volumetric incentive rate ~~Payments for energy generated from the qualifying system~~ must be paid monthly. Retail electricity consumers may request that:

(1) Payments be paid directly to the consumer each month; the consumer will continue to receive a standard monthly bill for electricity purchased under a scheduled tariff; or

(2) The electric company aggregate generation payments from up to two pilot program contracts with the standard monthly bill for electricity purchased under the consumer's existing tariff; or

(3) The electric company assign payments to a third party. An electric company may impose a **reasonable** fee, for account setup, for this alternative.

Stat Auth: 2009 OR Laws Ch. 748

Stats. Implemented: 2009 OR Laws Ch. 748

Hist: NEW

INTERCONNECTION: APPLICATION AND AGREEMENTS

860-084-0260

Interconnection Requirements for Solar Photovoltaic Pilot Program

(1) As established in OAR 860-084-0110(d), a qualifying system must be certified as complying with the requirements of section (2) of this rule.

(2) To be qualified for interconnected operation, a system must be certified as complying with the following standards as applicable:

(a) IEEE **1547 and other applicable** standards; and

(b) UL 1741 Inverters, Converters, and Controllers for Use in Independent Power Systems ~~(January 2001).~~

(3) A system is considered as certified to the standards of section (2) of this rule, and the electric company may not require further design review, testing or additional equipment, if:

(a) The system components ~~is a complete equipment package that~~ **have** been submitted by a manufacturer to a nationally recognized testing and certification laboratory, and **have** ~~has~~ been tested and listed by the laboratory for continuous interactive operation with an electric distribution system in compliance with the applicable codes and standards listed in section (2) of this rule; or

~~(b) The system is an equipment package which includes a generator or other electric source and the equipment package has been tested and listed as an integrated package in compliance with the applicable codes and standards listed in section (2) of this rule, or~~

~~(c) The certified equipment package comprises only the interface components (switchgear, inverters, or other interface devices) and the interconnection applicant has shown that~~

~~(A) The solar photovoltaic energy system being utilized is compatible with the equipment package,~~

~~(B) Testing and listing of the solar photovoltaic generator being utilized, as performed by the nationally recognized testing and certification laboratory, is consistent with the testing and listing of the interface component equipment package, and~~

~~(C) The testing and listing specified for the package is consistent with the applicable codes and standards listed in section (2) of this rule.~~

(4) A qualifying system may not interconnect to a transmission line.

Stat Auth: 2009 OR Laws Ch. 748

Stats. Implemented: 2009 OR Laws Ch. 748

Hist: NEW

860-084-0270
Authorization to Interconnect

(1) A person may not interconnect an eligible system to an electric company's distribution system without authorization from the electric company.

(2) A person proposing to interconnect an eligible system to an electric company's distribution system must submit an application for interconnection to the electric company.

(3) A person with contracted system who proposes to make any change to the facility, other than a minor equipment modification, must submit an application to the electric company. Changes affecting the nameplate capacity or the output capacity of the system authorized in the agreement governing the contract require that the applicant apply for an additional capacity reservation and for a new interconnection review.

(4) An application for interconnection must be submitted on a standard form, available from the electric company and posted on the electric company's website. The submission of a completed application launches the process of interconnection review. The application form must require the following types of information:

(a) The name of the applicant and the electric company involved;

(b) The type and specifications of the complete equipment package of the solar photovoltaic energy system, including the solar photovoltaic generator;

(c) The Level of interconnection review sought; e.g. Level 1, Level 2 or Level 3;

(d) The contractor who will install the solar photovoltaic energy system;

(e) Equipment certifications;

(f) The anticipated date the solar photovoltaic energy system will be operational; and

(g) Other information that the utility deems is necessary to determine compliance with these solar photovoltaic pilot program interconnection rules.

(5) Within three business days after receiving an application for Level 1, Level 2 or Level 3 interconnection review, the electric company must provide written or electronic mail notice to the applicant that it received the application and whether the application meets established criteria.

(a) If the application does not meet established criteria, the written notice must include a list of all of the information needed to complete the application.

(b) If the number of applications received in a day exceeds 20, the electric company may notify customers by electronic mail that the company will respond within ten business days.

(6) Each electric company must designate an employee or office from which an applicant can obtain basic application forms and information through an informal process; this process must be outlined and posted on the electric company's website. On request, the electric company must provide all relevant forms, documents, and technical requirements for submittal of an application that meets established criteria for an interconnection application under these solar photovoltaic pilot program rules, as well as specific information necessary to contact the electric company representative assigned to review the application.

(7) A person may also request information about the feasibility of interconnecting a qualifying system, in advance of filing an application for capacity reservation or interconnection. The information provided by the electric company in response to this request must include relevant existing studies and other materials that may be used to understand the feasibility of interconnecting a solar photovoltaic facility at a particular point on the electric company's distribution system. The electric company must comply with reasonable requests for access to or copies of such information, except to the extent that providing such materials would violate security requirements, confidentiality obligations to third parties, or be contrary to federal or state regulations. The electric company may require a person to sign a confidentiality agreement if required to protect confidential or proprietary information. A person requesting information under this section must reimburse the electric company for the reasonable costs of gathering and copying the requested information.

(8) The electric company is not responsible for the cost of determining the rating of equipment on the customer side of the meter.

Stat Auth: 2009 OR Laws Ch. 748

Stats. Implemented: 2009 OR Laws Ch. 748

Hist: NEW

860-084-0280

Interconnection Cost Responsibility

(1) For a Level 1 interconnection review, the electric company may not charge any fees, unless otherwise directed by the Commission.

(2) For a Level 2 or Level 3 interconnection review, the electric company may charge an application fee, as established by Commission order. If an interconnection request is denied by the electric company, this fee must be refunded to the applicant.

(3) Except as provided in OAR 860-084-0290, all interconnection costs associated with the meter, interconnection facilities, modifications to the electric distribution system, interconnection review, or system upgrades are at the electric company's expense.

(a) Interconnected systems must be equipped with metering equipment that can measure the flow of electricity in both directions and comply with ANSI C12.1 standards and OAR 860-023-0015. The customer may determine the location of the meter.

(b) The electric company constructs, owns, operates, and maintains the meter and applicable interconnection facilities on the company side of the meter.

(c) The retail electricity consumer chooses the location of the meter and is responsible for the costs of connection between the eligible system and the meter.

(4) A retail electricity consumer who is reinstalling a contracted system, and is eligible to continue in the solar photovoltaic pilot program under an existing standard contract, must pay the expense of the meter, interconnection equipment, modifications to the electric distribution system, interconnection review, or system upgrades in the new location as applicable.

Stat Auth: 2009 OR Laws Ch. 748

Stats. Implemented: 2009 OR Laws Ch. 748

Hist: NEW

860-084-0290
Reasonable Costs

(1) The electric company may deny an interconnection application that exceeds a reasonable cost standard, as given in section (2) of this rule.

(2) Each electric company must file, as part of periodic updates to the Commission, a list of interconnection requests that are denied. This list must include name and billing address of retail electricity consumer and intended installation address and interconnection location.

(3) The Commission will, by Order, establish a "reasonable cost" standard to limit the costs associated with the costs of interconnection review, installation, additional interconnection facilities, minor modifications, and system upgrades that are borne by the electric company in the installation of a solar photovoltaic energy system under this pilot program. Before applying the reasonable cost standard, the electric company must determine that the identified electrical system changes or upgrades would not be performed by the electric company in the normal operation and maintenance of its system or in compliance with other Commission Order.

(4) The Commission will, by Order, establish the processes that an applicant may follow to complete installation of the system denied. These processes may include, but will not be limited to, processes whereby the applicant may choose to pay the difference between estimated and reasonable costs.

(5) An applicant may choose to pay for interconnection costs above the "reasonable cost" standard without obtaining a Commission Order.

Stat Auth: 2009 OR Laws Ch. 748

Stats. Implemented: 2009 OR Laws Ch. 748

Hist: NEW

860-084-0300
Insurance

An electric company may not require a contracted system to obtain liability insurance in order to interconnect with the electric company's distribution system.

Stat Auth: 2009 OR Laws Ch. 748

Stats. Implemented: 2009 OR Laws Ch. 748

Hist: NEW

860-084-0310
Level 1 System Interconnection Review

(1) An eligible system meeting the following criteria is eligible for Level 1 interconnection review:

(a) The facility is inverter-based; and

(b) The facility has a capacity of 25 kilowatts or less.

(2) The electric company must approve interconnection under the Level 1 interconnection review procedure if:

(a) The aggregate generation capacity on the distribution circuit to which the eligible system will interconnect, including the capacity of the eligible system, may not contribute more than 10 percent to the distribution circuit's maximum fault current at the point on the high voltage (primary) level that is nearest the proposed point of common coupling.

(b) An eligible system's point of common coupling may not be on a transmission line, a spot network, or an area network.

(c) If an eligible system is to be connected to a radial distribution circuit, the aggregate generation capacity connected to the circuit, including that of the eligible system, may not exceed 15 percent of the circuit's total annual peak load, as most recently measured at the substation.

(d) If an eligible system is to be connected to a single-phase shared secondary, the aggregate generation capacity connected to the shared secondary, including the eligible system, may not exceed 20 kilovolt-amps.

(e) If a single-phase eligible system is to be connected to a transformer center tap neutral of a 240 volt service, the addition of the eligible system may not create a current imbalance between the two sides of the 240 volt service of more than 20 percent of nameplate rating of the service transformer.

(3) Within 10 business days after the electric company notifies a Level 1 applicant that the application is complete, the electric company must notify the applicant that:

(a) The eligible system meets all applicable criteria and the interconnection is approved upon installation of any required meter upgrade, completion of any required inspection of the facility, and execution of an interconnection agreement; or

(b) The eligible system has failed to meet one or more of the applicable criteria and the interconnection application is denied.

(4) If an electric company does not notify a Level 1 applicant in writing or by electronic mail whether the interconnection is approved or denied within 20 business days after the receipt of an application, the interconnection will be deemed approved. Interconnections approved under this section remain subject to section 7 below.

(5) Within three business days after sending the notice to an applicant that the proposed interconnection meets the Level 1 requirements, an electric company must notify the applicant:

(a) Whether an inspection of the eligible system for compliance with these interconnection rules is required prior to the operation of the system; and

(b) That an interconnection agreement is required for the eligible system. The electric company must also execute and send to the applicant a Level 1 interconnection agreement, unless the applicant has already submitted such an agreement with its application for interconnection.

(6) On receipt of an executed interconnection agreement from the applicant and satisfactory completion of any required inspection, the electric company must approve the interconnection, conditioned on compliance with all applicable building codes.

(7)The retail electric customer must notify the electric company of the anticipated start date for operation of the eligible system at least five business days prior to starting operation, either through the submittal of the interconnection agreement or in a separate notice. If the electric company requires an inspection of the eligible system, the applicant may not begin operating the facility until satisfactory completion of the inspection.

(8) If an application for Level 1 interconnection review is denied because it does not meet one or more of the applicable requirements in this rule, an applicant may resubmit the application under the Level 2 or Level 3 interconnection review procedure, as appropriate.

Stat Auth: 2009 OR Laws Ch. 748

Stats. Implemented: 2009 OR Laws Ch. 748

Hist: NEW

860-084-0320

Level 2 System Interconnection Review

(1) An electric company must apply the following Level 2 interconnection review procedure for an application to interconnect an eligible system that meets the following criteria:

(a) The facility has a capacity of 500 kilowatts or less; and

(b) The facility does not qualify for or failed to meet applicable Level 1 interconnection review procedures.

(2) The electric company must approve interconnection under the Level 2 interconnection review procedure if:

(a) The aggregate generation capacity on the distribution circuit to which the eligible system will interconnect, including the capacity of the eligible system, will not cause any distribution protective equipment (including, but not limited to, substation breakers, fuse cutouts, and line reclosers), or customer equipment on the electric distribution system, to exceed 90 percent of the short circuit interrupting capability of the equipment. In addition, an eligible system may not be connected to a circuit that already exceeds 90 percent of the short circuit interrupting capability, prior to interconnection of the facility.

(b) If there are posted transient stability limits to generating units located in the general electrical vicinity of the proposed point of common coupling, including, but not limited to within three or four transmission voltage level busses, the aggregate generation capacity, including the eligible system, connected to the distribution low voltage side of the substation transformer feeding the distribution circuit containing the point of common coupling may not exceed 10 megawatts.

(c) The aggregate generation capacity connected to the distribution circuit, including the eligible system, may not contribute more than 10 percent to the distribution circuit's maximum fault current at the point on the high voltage (primary) level nearest the proposed point of common coupling.

(d) If an eligible system is to be connected to a radial distribution circuit, the aggregate generation capacity connected to the electric distribution system by non-electric company sources, including the eligible system, may not exceed 15 percent of the total circuit annual peak load. For the purposes of this subsection, annual peak load will be based on measurements taken over the 12 months previous to the submittal of the application, measured for the circuit at the substation nearest to the eligible system.

(e) If an eligible system is to be connected to three-phase, three wire primary electric company distribution lines, a three-phase or single-phase generator must be connected phase-to-phase.

(f) If an eligible system is to be connected to three-phase, four wire primary electric company distribution lines, a three-phase or single-phase generator must be connected line-to-neutral and must be effectively grounded.

(g) If an eligible system is to be connected to a single-phase shared secondary, the aggregate generation capacity on the shared secondary, including the eligible system, may not exceed 20 kilovolt-amps.

(h) If an eligible system is single-phase and is to be connected to a transformer center tap neutral of a 240 volt service, the addition of the eligible system may not create a current imbalance between the two sides of the 240 volt service that is greater than 20 percent of the nameplate rating of the service transformer.

(i) An eligible system's point of common coupling may not be on a transmission line.

(j) If an eligible system's proposed point of common coupling is on a spot or area network, the interconnection must meet the following additional requirements:

(A) For an eligible system that will be connected to a spot network circuit, the aggregate generation capacity connected to that spot network from the eligible system, and any generating facilities, may not exceed five percent of the spot network's maximum load;

(B) For an eligible system that utilizes inverter-based protective functions, which will be connected to an area network, the eligible system, combined with any other generating facilities on the load side of network protective devices, may not exceed 10 percent of the minimum annual load on the network, or 500 kilowatts, whichever is less. The percent of minimum load must be calculated based on the minimum load occurring during an off-peak daylight period; and

(C) For an eligible system that will be connected to a spot or an area network that does not utilize inverter-based protective functions, or for an inverter-based eligible system that does not meet the requirements of paragraphs (A) or (B) of this subsection, the eligible system must utilize low forward power relays or other protection devices that ensure no export of power from the eligible system, including inadvertent export (under fault conditions) that could adversely affect protective devices on the network.

(3) Within 15 business days after notifying a Level 2 applicant that the application is complete, the electric company must perform an initial review of the proposed interconnection to determine whether the interconnection meets the applicable criteria. During this initial review, the electric company may, at its own expense, conduct any studies or tests it deems necessary to evaluate the proposed interconnection and provide notice to the applicant of one of the following determinations:

(a) The eligible system meets the applicable requirements and that interconnection will be approved following any required inspection of the facility and fully executed interconnection agreement. Within three business days after this notice, the electric company must provide the applicant with an executable interconnection agreement;

(b) The eligible system failed to meet one or more of the applicable requirements, but the electric company determined that the eligible system may be interconnected consistent with safety, reliability, and power quality. In this case, the electric company must notify the applicant that the interconnection will be approved following any required inspection of the facility and fully executed interconnection agreement. Within five business days after this notice, the electric company must provide the applicant with an executable interconnection agreement; or

(c) The eligible system failed to meet one or more of the applicable requirements, and that additional review would not enable the electric company to determine that the eligible system could be interconnected consistent with safety, reliability, and power quality. In such a case, the electric company must notify the applicant that the interconnection application has been denied and must provide an explanation of the reason(s) for the denial, including a list of additional information, or modifications to the eligible system, or both, which would be required in order to obtain an approval under Level 2 interconnection procedures.

(4) An applicant that receives an interconnection agreement under subsection (3)(a) or (3)(b) of this rule must:

(a) Execute the agreement and return it to the electric company at least 10 business days prior to starting operation of the eligible system (unless the electric company does not so require); and

(b) Indicate to the electric company the anticipated start date for operation of the eligible system.

(5) The electric company may require an electric company inspection of an eligible system for compliance with these solar photovoltaic rules prior to operation, and may require and arrange for witness of commissioning tests as set forth in IEEE standards. The electric company must schedule any inspections or tests under this section promptly and within a reasonable time after submittal of the application. The applicant may not begin operating the eligible system until after the inspection and testing is completed.

(6) Approval of interconnected operation of any Level 2 eligible system must be conditioned on all of the following occurring:

(a) Approval of the interconnection by the electrical code official with jurisdiction over the interconnection;

(b) Successful completion of any electric company inspection or witnessing of commissioning tests, or both, requested by the electric company; and

(c) Passing of the planned start date provided by the applicant.

(7) If an application for Level 2 interconnection review is denied because it does not meet one or more of the requirements of this rule, the applicant may resubmit the application under the Level 3 interconnection review procedure.

Stat Auth: 2009 OR Laws Ch. 748

Stats. Implemented: 2009 OR Laws Ch. 748

Hist: NEW

860-084-0330
Level 3 System Interconnection Review

(1) The electric company must apply the Level 3 review procedure for an application to interconnect an eligible system that meets the following criteria:

(a) The facility has a capacity of 500 kilowatts or less; and

(b) The facility does not qualify or failed to meet Level 2 interconnection review procedures.

(2) Following receipt of a Level 3 application and within three business days of a request from the applicant, the electric company must provide pertinent information to the applicant, such as the available fault current at the proposed interconnection location, the existing peak loading on the lines in the general vicinity of the eligible system, and the configuration of the distribution lines at the proposed point of common coupling.

(3) Within seven business days after receiving a complete application for Level 3 interconnection review, the electric company must conduct an impact study which includes a good faith cost estimate for determination of whether the electric company costs comply with the Reasonable Cost standard, as defined in OAR 860-084-0290. The impact study must be conducted in accordance with good utility practice and must:

(a) Detail the impacts to the electric distribution system that would result if the eligible system were interconnected without modifications to either the eligible system or to the electric distribution system;

(b) Identify any modifications to the electric company's electric distribution system that would be necessary to accommodate the proposed interconnection; and

(c) Focus on power flows and utility protective devices, including control requirements; and

(d) Include the following elements, as applicable:

(A) A load flow study;

(B) A short-circuit study;

(C) A circuit protection and coordination study;

(D) The impact on the operation of the electric distribution system;

(E) A stability study, along with the conditions that would justify including this element in the impact study;

(F) A voltage collapse study, along with the conditions that would justify including this element in the impact study.

(4) The electric company must complete the impact study and must notify the applicant within 30 calendar days of one of the following results:

(a) Only minor modifications to the electric company's electric distribution system are necessary to accommodate interconnection. In such a case, the electric company must approve the application and send the applicant an interconnection agreement; or

(b) The eligible system may be safely interconnected, substantial modifications to the electric company's electric distribution system are necessary to accommodate the proposed interconnection, and the costs associated with the substantial modifications meet the criteria as defined in OAR 860-084-0290. In such a case, the electric company must approve the application and send the applicant an interconnection agreement; or

(c) The eligible system may be safely interconnected, substantial modification to the company's electric system are necessary to accommodate the proposed interconnection, and the interconnection costs exceed the reasonable cost standard defined in OAR 860-084-0290. In such a case, the applicant may request a binding estimate of the cost of those facilities that is above the reasonable cost standard and of the estimated time required to build and install those facilities. The applicant may choose to pay the cost of the facilities above the reasonable cost standard and request the approval of the interconnection application.

(5) If the proposed interconnection may affect electric transmission or delivery systems other than those controlled by the electric company, operators of those other systems may require additional studies to determine the potential impact of the interconnection on those systems. If such additional studies are required, the electric company must coordinate the studies but is not responsible for their timing.

(6) If an applicant requests a facilities study under subsection (4)(b), the electric company must provide an interconnection facilities study agreement. The interconnection facilities study agreement must describe the work to be undertaken in the interconnection facilities study and must include a non-binding, good faith estimate of the cost to the applicant for completion of the study. Upon execution by the applicant of the interconnection facilities study agreement, the electric company must conduct an interconnection facilities study to identify the facilities necessary to safely interconnect the eligible system with the electric company's electric distribution system, and if the costs associated with this interconnection exceed the reasonable cost standard defined in OAR 860-084-0290, to propose a non-binding, good faith estimate of the cost of those facilities and the time required to build and install those facilities.

(7) Upon completion of an interconnection facilities study, the electric company must provide the applicant with the results of the study and an executable interconnection agreement. The agreement must list the conditions and facilities necessary for the eligible system to safely interconnect with the electric company's electric distribution system.

(8) If the applicant wishes to interconnect, it must execute the interconnection agreement and return it to the electric company at least 10 business days prior to starting operation of the eligible system, unless the electric company does not so require.

(9) If the applicant wishes to interconnect under the terms of a reasonable costs exception, the applicant must pay a deposit of not more than 50 percent of the estimated cost of the facilities identified in the interconnection facilities study, complete installation of the eligible system, and agree to pay the electric company the actual installed cost of the facilities needed

to interconnect as identified in the interconnection facilities study.

(10) Within 15 business days after notice from the applicant that the eligible system has been installed, the electric company must inspect the eligible system and must arrange to witness any commissioning tests required under IEEE standards. The electric company and the applicant must select a date by mutual agreement for the electric company to witness commissioning tests.

(11) If the eligible system satisfactorily passes required commissioning tests, if any, the electric company must notify the applicant in writing, within three business days after the tests, of one of the following:

(a) The interconnection is approved and the eligible system may begin operation; or

(b) The interconnection facilities study identified necessary construction that has not been completed, the date upon which the construction must be completed, and the date when the eligible system may begin operation.

(12) If the commissioning tests are not satisfactory, the applicant must repair or replace the unsatisfactory equipment to reschedule a commissioning test.

Stat Auth: 2009 OR Laws Ch. 748

Stats. Implemented: 2009 OR Laws Ch. 748

Hist: NEW

860-084-0340

Installation, Operation, Maintenance, and Testing of Contracted Systems

A contracted system must include and maintain a manual disconnect switch that will disconnect the solar photovoltaic energy system from the electric company's system.

(1) The disconnect switch must be a lockable, load-break switch that plainly indicates whether it is in the open or closed position.

(2) The disconnect switch must be readily accessible to the electric company at all times.

(3) The electric company must install the required disconnect switch at the electric company's expense.

(4) For customer services of 600 volts or less, an electric company may not require a disconnect switch for an eligible system that is inverter-based with a maximum rating as shown below.

(a) Service type: 240 Volts, Single-phase, 3 Wire—Maximum size 7.2 kilowatts

(b) Service type: 120/208 Volts, 3-Phase, 4 Wire—Maximum size 10.5 kilowatts

(c) Service type: 120/240 Volts, 3-Phase 4 Wire—Maximum size 12.5 kilowatts

(d) Service type: 277/480, 3-Phase, 4 Wire—Maximum size 25.0 kilowatts

(e) For other service types, the eligible system must not impact the retail electric consumers' service conductors by more than 30 amperes.

Stat Auth: 2009 OR Laws Ch. 748

Stats. Implemented: 2009 OR Laws Ch. 748

Hist: NEW

860-084-0350

Requirements after Approval of a Solar Photovoltaic Interconnection

(1) Once a contracted system has been approved under these solar photovoltaic

interconnection rules, the electric company may not require a retail electric consumer to test or perform maintenance on its facility except for:

(a) An annual test in which the contracted system is disconnected from the electric company's equipment to ensure that the inverter stops delivering power to the grid;

(b) Any manufacturer-recommended testing or maintenance;

(c) Any post-installation testing necessary to ensure compliance with IEEE standards or to ensure safety; and

(d) Testing required if the retail electric customer replaces a major equipment component that is different from the originally installed model.

(2) When a contracted system undergoes maintenance or testing in accordance with the requirements of these solar photovoltaic interconnection rules, the retail electric consumer must retain written records for seven years documenting the maintenance and the results of testing.

(3) An electric company has the right to inspect a retail electric consumer’s facility after interconnection approval is granted, at reasonable hours and with reasonable prior notice to the retail electric consumer. If the electric company discovers that the contracted system is not in compliance with the requirements of these solar photovoltaic interconnection rules, the electric company may require the retail electric consumer to disconnect the contracted system until compliance is achieved.

Stat Auth: 2009 OR Laws Ch. 748

Stats. Implemented: 2009 OR Laws Ch. 748

Hist: NEW

Rates and Cost Recovery

860-084-0360

Volumetric Incentive Rates

(1) A retail electricity consumer participating in a pilot program receives payments for the electricity delivered to the electric company from the consumer’s contracted system as follows:

(a) For 15 years from the date of the consumer’s date of enrollment, the payment equals the product of the kilowatt-hours of electricity delivered to the electric company and the applicable volumetric incentive rate per kilowatt-hour, with the applicable rate per kilowatt-hour determined from rates or through a rate formula in a rate schedule in effect at the date of capacity reservation.

(b) The payment thereafter equals the product of the kilowatt-hours of electricity delivered to the electric company and a volumetric incentive rate equal to the annual resource value per kilowatt-hour.

(2) Rates for payment under this rule are established by Commission Order. Electric companies must file compliance tariffs incorporating the rates established by the Commission.

(3) The Commission will establish initial volumetric incentive rates to enable participation in the pilot programs to begin April 1, 2010.

(4) The Commission will periodically consider adjusting rates to meet targeted levels of participation as follows:

(a) Commission staff must consult with interested parties and make a recommendation at a public meeting regarding the need to adjust volumetric incentive rates or make other changes in the pilot programs.

(b) Commission staff must make its recommendations in time to allow rate adjustments or program changes to occur on July 1, 2010, and every six months thereafter, and as otherwise directed by the Commission, for the term of the pilot programs.

Stat Auth: 2009 OR Laws Ch. 748
Stats. Implemented: 2009 OR Laws Ch. 748
Hist: NEW

860-084-0370
Resource Value

(1) On July 1 of 2010, 2012, and 2014, each electric company must file, for review in a Commission proceeding, its estimate of the 15-year levelized resource value for the company, along with supporting work papers.

(2) For the purpose of determining payments to retail electricity consumers at the end of the 15-year contract term, each electric utility must file, beginning January 1, 2025, and every January 1 thereafter, its estimates of the annual resource value for the company for each of the next five years.

Stat Auth: 2009 OR Laws Ch. 748
Stats. Implemented: 2009 OR Laws Ch. 748
Hist: NEW

860-084-0380
Cost Recovery and Rate Impacts

(1) An electric company may recover in rates all costs prudently incurred to offer the pilot program established under these rules, including, but not limited to, costs not otherwise reflected in rates for electricity usage related to:

(a) Payments for the output of contracted systems,

(b) Interconnection studies and related system modifications and upgrades, and

(c) Data collection and analysis for assessment of the company's pilot program.

(2) On July 1 of 2010, 2012, and 2014, and as otherwise directed by the Commission, each electric company must file for review in a Commission proceeding its estimates of the rate impact for each customer class of participation in its pilot program, along with supporting work papers.

(3) The Commission may establish total generator nameplate capacity limits for an electric company so that the rate impact of the pilot program for any customer class does not exceed 0.25 percent of the company's revenue requirement for the class in any year.

Stat Auth: 2009 OR Laws Ch. 748
Stats. Implemented: 2009 OR Laws Ch. 748
Hist: NEW

860-084-0390
Cost Recovery Mechanism

An electric company may request recovery of prudently incurred costs associated with compliance with the solar photovoltaic pilot program requirements. Mechanisms for recovery of cost associated with compliance will be established by Commission Order.

Stat Auth: 2009 OR Laws Ch. 748
Stats. Implemented: 2009 OR Laws Ch. 748
Hist: NEW

Data Collection and Reporting

860-084-0400
Data Collection

Except as provided in OAR 860-084-0410, each electric company must collect from the retail electricity consumer participating in the pilot program data on the installed solar photovoltaic energy system. The collected data elements must include, but are not limited to:

(1) Nameplate Capacity;
(2) Total Installed Cost;
(3) Photovoltaic module cost;
(4) Non- photovoltaic module cost (including other hardware, labor, overhead, and regulatory compliance costs);
(5) Total financing cost;
(6) Financing terms (including interest rate)
(7) System location;
(8) Technology type (building-integrated versus rack-mounted; crystalline silicon versus thin-film; solar tracking versus rack-mounted; etc.)
(9) Federal tax credit;
(10) In-service date;
(11) Expected annual energy output
(12) Date of certification of compliance
(13) Class of service of retail electricity consumer

Stat Auth: 2009 OR Laws Ch. 748

Stats. Implemented: 2009 Or Laws. Ch. 748

Hist: NEW

860-084-0410

Compliance with Pilot Program Requirements

(1) Electric companies must require pilot program participants, as a condition of participation in the pilot program, to certify, at the time of enrollment and at contract signing, that no investor in the qualifying system has accepted or will accept incentives from the Energy Trust of Oregon or Oregon State residential or business tax credits for the system contracted in the solar photovoltaic pilot program.

(2) Each electric company must send a list of all reserved and contracted systems that have completed this certification to the Energy Trust of Oregon, the Oregon Department of Revenue, or the Oregon Department of Energy, upon request by each organization. Data included in this listing includes, but is not limited to:

(a) Name and address of retail electricity consumer;

(b) Name and address of individual receiving volumetric incentive rate payments;

(c) Installation location of eligible or contracted system;

(d) In-service date; and

(e) Date of certification of Compliance.

Stat Auth: 2009 OR Laws Ch. 748

Stats. Implemented: 2009 OR Laws Ch. 748

Hist: NEW

860-084-0430

Data Availability

(1) Each electric company must verify that the data collected pursuant to OAR 860-084-0400 and OAR 860-084-0420 has been recorded in an appropriate electronic database prior to making volumetric incentive rate payments to participating retail electricity consumers.

(2) Each electric company must provide the data collected pursuant to OAR 860-084-0400 and OAR 860-084-0420, in a format established by the Commission, upon request. Reports that include this raw data and a summary of this data for the pilot program to date, must be provided to the Oregon Department of Energy, the Energy Trust of Oregon, the Oregon Department of Revenue, and to the Commission, quarterly, on the 15th day of the first month of each calendar quarter.

(3) Each electric company must make graphically visible, on a **publicly** ~~publically~~ accessible website, the general locations and sizes of reserved and contracted systems. This information must not include consumer names or installation addresses ~~or total capacity deployed to date~~.

Stat Auth: 2009 OR Laws Ch. 748

Stats. Implemented: 2009 OR Laws Ch. 748

Hist: NEW

860-084-0440
Pilot Program Overhead

(1) Electric companies must contribute to Commission-led evaluations of solar photovoltaic pilot programs through efforts including, but not limited to:

(a) Proposals for the design and execution of surveys to measure participant satisfaction with and recommendations for improving the pilot program processes,

(b) Proposals for the design and execution of surveys to solicit participant decision processes in choosing between the volumetric incentive rate program and the net-metering program, combined with tax credits and Energy Trust incentives, and

(c) Comment on Commission recommendations for regulatory policy changes that can lead to the increased use of solar photovoltaic energy systems, making solar photovoltaic systems more affordable, reducing the cost of incentives to utility customers, and promoting the development of the solar industry in Oregon.

(2) Each electric company may enter into a contract with the Energy Trust of Oregon to provide data collection and summary services required by OAR 860-084-0400 and OAR 860-084-0410. An electric company may also contract with the Energy Trust of Oregon to administer pilot programs, including capacity reservation services, survey execution or program evaluation. The Commission may direct the electric companies to contract with the Energy Trust of Oregon, if the Commission judges that the costs to administer individual pilot programs are unreasonable.

Stat Auth: 2009 OR Laws Ch. 748

Stats. Implemented: 2009 OR Laws Ch. 748

Hist: NEW

860-084-0450
Reports to the Legislature

The Commission must open a docket on or before November 1 of each even-numbered calendar year to receive public comment and recommendations on the draft reports prepared by Commission staff regarding the pilot programs.

Stat Auth: 2009 OR Laws Ch. 748

Stats. Implemented: 2009 OR Laws Ch. 748

Hist: NEW

CERTIFICATE OF SERVICE

I hereby certify that I served the foregoing **COMMENTS OF RENEWABLE NORTHWEST PROJECT AND PARTNERS ON PUC STAFF'S STRAW PROPOSAL FOR FEED-IN TARIFF DESIGN** on the following persons on January 14, 2010, by hand-delivering, faxing, e-mailing, or mailing (as indicated below) to each a copy thereof, and if mailed, contained in a sealed envelope, with postage paid, addressed to said attorneys at the last known address of each shown below and deposited in the post office on said day at Portland, Oregon:

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DATED this 14th day of January, 2010.

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