BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

UM 1673

In the Matter of OREGON PUBLIC UTILITY COMMISSION Staff Questions for Parties on the Solar Incentive Program Report under HB 2893.	Comments from the Sierra Club in response to Staff Questions for Parties on Solar Incentive Program Report under HB 2893

The Sierra Club appreciates the opportunity to participate in this proceeding, to offer our thoughts on the proposed scope of the Solar Incentive Program Report to the legislature under HB 2893, and to provide these comments on the value of solar photovoltaic (PV) distributed generation. We believe that solar PV has a bright future in Oregon, particularly in regard to its potential to unlock substantial benefits for the collective of consumers, taxpayers, and ratepayers in this state. Sierra Club notes that, as with all public policy initiatives, the method and structure of policy implementation can have a profound impact on outcomes. The series of questions distributed by Commission Staff on November 21, 2013 raise important issues that inform optimal policy design. Sierra Club appreciates the opportunity to submit these comments to aid the Commission in that goal.

The Sierra Club is a state-wide and national advocate for clean, renewable energy to reduce air pollution, water pollution, and the effects of climate disruption resulting from fossil fuel extraction and combustion. In Oregon, the Sierra Club has been part of multiple state legislative efforts to pass Oregon energy policies including Oregon's renewable portfolio and energy efficiency standards. The Sierra Club also engages at the grassroots level, working with individual businesses to connect our approximately 20,000 members and supporters in Oregon with opportunities to increase the energy efficiency of their homes and install rooftop solar. Our overall interest in this proceeding is to help the Commission and the State of Oregon identify and implement opportunities to dramatically increase solar installation in our state to the benefit of taxpayers, ratepayers, and Oregon's environment.

Our responses generally follow the structure posed by Commission staff, but in some instances we depart from this structure in order to elucidate points that fall under more than one specific question or section.

Q1. What is the primary goal in supporting solar?

Goal-setting should be a threshold consideration and is an important element of any public policy decision. The framing of this question suggests that there might be a singular goal that should take priority above all other possible goals. We decline to do this, because we believe that promoting solar can achieve numerous public policy goals that are, to a large degree, of equal importance and significance. Consequently, we suggest the following as *primary goals* of promoting solar in Oregon:

- Maximize the amount of installed solar PV generation in Oregon;
- Reduce carbon dioxide emissions from traditional electricity generation methods by increasing the amount of solar in the generation mix, and correspondingly diversifying Oregon's energy mix;
- Maximize the use of the existing built environment (i.e., rooftops) towards these ends, and avoid other adverse land-use impacts often present in energy development (e.g., clearing of land and habitat destruction or disruption associated with transmission development);
- Allow all energy consumers to directly participate in deciding how their energy needs are supplied, and creating avenues for them to reduce the adverse environmental impacts of that supply;
- Create an environment where a historically underutilized resource can grow and prosper in a sustainable manner through the gradual maturation of the technology and associated markets; and
- Support in-state economic growth.

We would also like to note that the question posed appears to relate to promoting solar in a general sense. Consistent with the focus of HB 2983, we suggest that the scope of this particular report be limited to addressing the need for, barriers to, and incentives required to increase production of distributed solar in Oregon. While this somewhat vague term may mean different things to different people, we use it to refer to installations that are located at or near customer load sites, rather than utility-scale projects that are typically sited away from customer loads and intended to function as central-station electricity generation facilities. As participants in the negotiations that led to the passage of HB 2893 and the requirement of this report, the Sierra Club believes that the intent of HB 2893 is to focus on developing and incentivizing distributed solar. While a discussion of utility scale solar in Oregon is important, such a review is best accomplished outside of this proceeding as part of the envisioned and ongoing efforts to realize Governor Kitzhaber's 10-year energy plan.

Q2. What is the proper role of the utility in developing solar?

The role of the utility in developing solar should be one of a collaborator, partner, and facilitator. This means that utilities should accommodate the development of customer-sited solar PV to the largest extent possible and in a proactive manner that continually seeks to maximize the ability of energy consumers to make investments in, and benefit from, on-site solar generation. In this respect, we see the role of utilities to fall less within the realm of development than in facilitating development by others.

Our recommended role for utilities is not meant to prevent utilities from engaging in solar development activities, especially if the utilities' activities support the set of goals described above in a manner that does not reduce opportunities for non-utility development. In other words, utility solar development activities should be designed to offer additional consumer opportunities and, to the extent that they compete with services provided by non-utilities, do so on a level, competitive playing field that provides no unfair advantages to either type of service.

Q3. What are the solar incentive programs under evaluation?

Q3a. What programs are currently in place in Oregon?

The primary solar incentive programs that currently exist in Oregon are as follows:

1.) The Volumetric Incentive Rate (VIR)
2.) The Oregon Energy Trust Solar Incentives program
3.) The Residential Energy Tax Credit

The VIR is an exclusive incentive, meaning that it cannot be combined with the Residential Energy Tax Credit or the Oregon Energy Trust incentive. The Oregon Energy Trust incentive may be combined with the Residential Energy Tax Credit, and both incentives may be combined with net metering. We believe that all of these programs are worthy of evaluation, in that they operate in concert with one another and their individual terms undoubtedly determine consumer decisions to install solar.

Sierra Club notes that net metering is sometimes framed in terms of an "incentive" program, but we generally disputes this designation. While net metering is an important aspect of solar policy, it should not be characterized as an incentive but rather a billing mechanism used to facilitate customer installation of distributed solar generation. There is considerable disagreement in public policy circles over whether net metering produces a subsidy in favor of participating customers. The Commission should avoid any presumptions to this effect absent a comprehensive and transparent cost-benefit analysis of the program. Our more detailed thoughts on this issue are provided in our responses related to the distribution of costs and benefits among retail electricity consumers (see Question 12).

Q3b. What programs outside of Oregon may be worth examining?

The suite of solar incentive programs offered in other states is expansive and characterized by a variety of program designs that frequently reflect other components of a state's energy, renewable energy, and solar energy policies (e.g., the terms of a renewable portfolio standard and/or solar carve-out or the existence of retail competition). Consequently, in some cases, those designs may be difficult to replicate entirely in Oregon, given that they arose under a different set of conditions and in response to characteristics of a specific state solar market.

That said, at a broad level, programs can be divided into two categories: those that provide an energy purchase in conjunction with the purchase of renewable energy credits (RECs) under a long-term contract, and those that rely on net metering in conjunction with separate incentives, often in exchange for the RECs produced by a system. These two options essentially define the "transaction" content of an incentive program.[1] We refer to the former as the "bundled" model because the RECs remain "bundled" with the energy. This model is also sometimes referred to as a "feed-in tariff (FiT)", though we avoid using this term because to some it suggests very specific characteristics (e.g., minimum contract length). There are advantages and drawbacks to both approaches.

[1] A few states also display some reliance on other incentives, most notably state tax credits (e.g., North Carolina, Louisiana, and Oregon).

Net metering has the advantages of being relatively simple and easily understood by consumers (often visualized as an electric meter rolling backwards); directly insulating consumers from the future electricity price increases that most expect; being generally considered a non-taxable arrangement (though separate REC sales might be considered taxable income); and, due to its prevalence, being a foundational element of the third-party owned (TPO) solar business model (i.e., solar leases and retail power purchase agreements).

Bundled models have been advocated for on the basis that they facilitate financing by providing a guaranteed long-term revenue stream, in contrast to some net metering and REC-based programs where REC sales revenue is not guaranteed. However, growth of the bundled model has been stymied in the U.S. largely due to concerns over the legality of above-market rate setting, and the perception that "locking in" the rates paid over the long-term frustrates the ability of markets to progressively lower the costs of the incentive.

Where bundled rates or tariffs have been employed, they have also been victims of their own success, creating a "boom-bust" cycle where available capacity is reserved in days or even minutes of the program start. To some degree, this reflects the difficulty of selecting the appropriate rate and has led some jurisdictions to pursue programs based on competitive solicitations. The same oversubscription effect has been seen in REC-only and non-REC-based programs, resulting in models that employ competitive procurements or frequent adjustments to incentive levels based on market conditions and program demand.

Both program models essentially grapple with the same issue of providing revenue certainty for participants while attempting to restrain costs by allowing incentive rates to reflect market forces. The chief differences are: (1) net metering programs have historically been "uncapped" in terms of available program capacity or have utilized caps that provide for greater participation; and (2) net metering programs are typically designed to limit individual system size to the amount needed to serve on-site needs. The practical effect is that under net metering, development is constrained to individual load sites and to the sizes of those loads, while bundled programs typically allow greater site freedom and the ability to maximize the size of systems according to the physical, rather than on-site load, constraints of a site.

By and large, the most successful solar incentive programs in other states (as measured by installed capacity) utilize a model that combines net metering with the provision of other incentives, usually involving a transfer of REC ownership from the participant to another entity (e.g., a utility). Excluding utility-scale projects, during 2012, all of the top ten states in new residential and non-residential installed solar capacity utilized net-metering-based programs.[2] While this measure of success is sensitive to population, if analyzed on a per capita basis, through 2012, nine of the top ten states in terms of cumulative installed capacity per capita utilize net metering in conjunction with other (typically REC-

[2] The top ten states in new residential and non-residential installed solar capacity are Arizona, California, Colorado, Hawaii, Maryland, Massachusetts, New Jersey, New York, Ohio, and Pennsylvania.

based) incentives.[3] While this measure includes contributions from utility-scale projects, it remains indicative of the fact that net metering is a core component of successful state solar programs.[4]

This is not to say that bundled REC and energy purchase programs cannot be successful, which they have been in many other countries. Rather, it should be taken to mean that in the United States, net metering has consistently been a core component of many of the most successful state solar programs when supplemented by other incentive programs. In this respect, it is the "tried and true" model, which has proven to be effective in many states.

Leaving aside the question of the incentive "transaction" content, we recommend that the Commission consider the following program design principles essential to fostering successful solar adoption by consumers. Our description of these principles is followed by examples of other state programs that illustrate how some of these principles have been applied in practice. We recognize that a number of these principles can operate cross-purposes to one another. While we do not believe that any "perfect" program design exists, thoughtful consideration of each design is necessary for identifying a suitable middle ground that reconciles the conflicts that do exist and best reflects program priorities and goals. Those design principles are as follows:

1.) Maintain certainty and transparency in terms of program availability and incentive levels;
2.) Create opportunities for participation by all sectors and types of consumers by ensuring accessibility and simplicity;
3.) Provide reasonable returns for participants while limiting costs;
4.) Create avenues for continuous or periodic program effectiveness evaluations; and
5.) Establish mechanisms that allow program terms to respond to changing market conditions.

Example #1: The California Solar Initiative (CSI)

The CSI was established as a long-term, continuously funded solar incentive program with clear overall program targets and a step-based incentive structure that provided for pre-determined incentive level reductions upon the achievement of installed capacity targets. It also utilizes specific residential and non-residential sector-specific allocations and a continuously updated website where consumers and industry professionals can track incentive availability under each step and plan accordingly. In contrast to several other examples provided herein, the CSI was established outside and separate from the California renewable portfolio standard (RPS) and does not require participants to surrender their RECs in exchange for an incentive.

This program design provides transparency in terms of incentive availability and levels, coupled with long-term certainty and predictability of both program funding for incentives and program costs borne by

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[3] The top ten states in cumulative installed capacity per capita are Arizona, California, Colorado, Delaware, Hawaii, Massachusetts, Nevada, New Mexico, New Jersey, New York, and Vermont. The one-in-ten exception to the per-capita installation figures is Vermont, which offers both a standard offer energy purchase program and net metering. In Vermont, 2012 installations were split roughly evenly between the standard offer energy purchase program and net metering installations.

[4] Interstate Renewable Energy Council. *U.S. Solar Market Trends 2012,* July 2013, *available at* http://www.irecusa.org/wp-content/uploads/2013/10/Solar-Rpt_Oct2013_FINAL.pdf

ratepayers. The sector-differentiated program structure provides incentives designed to meet the needs of both residential and non-residential customers, and the program includes further components for solar in newly-constructed homes, single-family, and multi-family affordable housing. The multi-family affordable housing component has also been supported by the establishment of a virtual net metering policy that allows participants to share in the generation produced by a central solar facility.

Example #2: Connecticut ZREC and Residential Solar Investment Programs

Similar to the current situation in Oregon with the VIR and Energy Trust programs, these two programs constitute consumer options that operate exclusive to one another, meaning that participation in one excludes the consumer from participation in the other. In both cases, the programs are authorized for multi-year periods with pre-established funding levels.

The ZREC (which stands for zero-emission REC) program offers 15-year fixed price REC contracts for customer-sited solar installations up to 1 MW. The program is open to new systems and those placed in service on or after July 1, 2011. For projects larger than 100 kW, contracts are awarded based on a competitive bidding process, while smaller projects are eligible for a standard offer contract. The standard offer price is reset annually based on the priced offers made within the most recent competitive solicitation for larger projects. During 2013, the program utilized a two-week open application window for the standard offer portion of the program, with all applications during that window considered to have arrived simultaneously. Thereafter, the program remained open for new applications, which were prioritized for awards based on their time of submission. Applications during the two-week open period exceeded available funding, resulting in a random selection process.

The Residential Solar Investment program provides another consumer option, but in contrast to the ZREC program, applies only to new projects. The program is differentiated based on the ownership arrangement, with customer-owned systems eligible for a tiered, up-front incentive that varies by system size and expected performance, and third-party owned systems eligible for a six-year performance-based incentive that accrues over time. Incentive levels are stepped down over time, but the steps are not pre-determined in advance. Instead, the program administrator periodically defines each new step and incentive level based on market conditions. Program status updates are published every one to two weeks, indicating the remaining capacity available in each step and the trigger points for incentive level revisions. The program also offers a state-arranged solar lease and a solar loan through competitively-selected providers.

The collective Connecticut solar programs are designed to provide multi-year incentive availability and certainty, if not definitive certainty of future incentive levels. The programs are transparent in terms of defining how incentive levels are determined, but the Residential Solar Investment program does permit market participants to view the current status of the program and forecast when and how future changes will be made. The collective programs excel at providing a suite of potential consumer options, and allowing the participant to select the most appropriate path according to their own goals. The periodic adjustments to the residential program and the annual review and solicitation protocol of the ZREC program allow for adjustments that reflect changing market conditions.

Example #3: New York Customer-Sited Tier Incentive Programs

New York offers separate incentive programs for customer-sited solar facilities of 200 kW or less and larger customer-sited solar facilities. Both programs are established on the basis of the targets for customer-sited renewables created under the New York RPS and are authorized through 2015 - the last year of the state's current RPS schedule. Likewise, since both programs are part of New York's centrally designed RPS model, both effectively involve the surrender of RECs because the associated generation is counted under the RPS.

The program for smaller systems is devised as a standard offer up-front incentive program, with tiers that offer lower incentives for larger systems. While the overall level of program funding is established on an annual basis, the program now utilizes a monthly budgeting system and a waitlist for applications that exceed the amount of monthly funding available. The available funding and waitlist levels are updated on a weekly basis and posted to the program web site. Changes to incentive levels are determined on a bi-monthly basis based on consumer demand, rather than according to a pre-determined schedule.

The program for facilities larger than 200 kW is based on periodic competitive solicitations (roughly quarterly), where participants bid a $/kWh incentive level for a single project or a collection of projects. Incentives are awarded solely on the basis of the bid amount, comprised of two separate up-front payments and three annual performance payments. The program has two unique design elements that bear mention. First, bonus incentives are awarded for projects located in designated Strategic Locations that have been determined as providing distribution grid benefits. Second, available funding is allocated on the basis of location (load zone) in the interest of aligning the geographic diversity of ratepayer collections that fund the program with incentive awards. This grouping also allows the incentive levels to reflect differences in retail power prices between the up-state and down-state portions of the state, because projects compete for funding within their location group rather than against projects in other portions of the state that may require lower or higher incentives due to these differences.

The collective New York programs illustrate how different programs may be designed distinctively in order to meet consumer needs and address related policy issues such as the equitable distribution of ratepayer funds and incentive requirement differentials between different portions of a state. Like the other programs mentioned here, they exhibit long-term program availability commitments and market adjustment mechanisms. For its part, the standard offer program has a less transparent incentive revision mechanism than other state programs, but participants are able to ascertain the current status of the program and anticipate when incentive changes are likely.

Separately, New York is also working to establish a "Green Bank" for the purpose of providing enhanced financing options for energy efficiency and renewable energy improvements and aligning state-provided incentive offerings with those of the Long Island Power Authority (LIPA) in order to provide a more consistent suite of programs available throughout the state. This last endeavor could be seen as an effort to increase accessibility and simplicity for solar providers, who currently must operate under the complications entailed by working in two distinct and separate markets.

Example #4: Utility REC-Purchase Programs in Arizona and Colorado

While the Arizona and Colorado solar markets differ in some ways, they have historically shared a similar incentive design structure. This structure is based on annual utility RPS procurement plan filings that result in standard-offer REC-purchase programs for customer-sited systems (coupled with net metering) with occasional competitive procurements for larger-scale customer-sited systems and utility-scale systems. The standard offers have used a mix of up-front incentives, typically for residential and small commercial systems, and performance-based incentives for larger commercial systems. One major difference between Oregon and these solar markets is that both Arizona and Colorado have established carve-outs within their RPS for distributed generation resources. This policy underpins and results in the annual utility program filings and associated REC-purchase program offerings.

Available program funding and incentive levels have historically been set on the basis of the level needed to meet the DG targets in the RPS. However, in instances where programs have been oversubscribed before the end of a program year, the existence of accelerating targets under the RPS in future years has allowed programs to be extended under the rationale that consistency is key to the industry, and the RECs purchased can be used to meet obligations in future years. The long-term RPS targets thus provide some degree of certainty for the industry, and a certain amount of flexibility with respect to program availability in any given year. The annual procurement plan filing requirements also allow market participants the opportunity to participate in the incentive design process in a transparent setting. These proceedings have also been a forum for the development of programs that address market gaps or underserved sectors, such as community solar and specific programs for public schools.

While this model has not been without its own issues, it has proven reasonably adept at maintaining transparency and certainty for solar providers, providing a mechanism for the establishment of novel programs, and allowing for consistent review and adjustment according to changing market conditions. Moreover, while both states utilize a net-metering-based model with incentives provided in the form of REC purchases for customer-sited systems, their structure is such that most often enrollment in both proceeds through a single, consolidated process. Thus, the model is simpler than those that require a REC transaction that is fully separate from net metering enrollment.

The examples cited above are certainly not the limit of possibilities, and the descriptions omit many details of program design and mechanics. For instance, the conduction of a competitive solicitation process that promotes certainty of project completion is a complex topic in and of itself. While in many ways, these details can have a profound effect on the success of a program, we believe it is more useful at this time to investigate different program models at a high level rather than become bogged down in the technical details of every program option. These finer program design elements can be examined at a later date.

Q4. How should solar incentive programs be evaluated?

The evaluation criteria and metrics should be based on goals and priorities of an individual program. Different priorities require the use of different metrics to arrive at any conclusions of program effectiveness. Therefore, we recommend that the Commission hold off on finalizing evaluation criteria until such time as overall program goals have been defined, and allow participants a separate opportunity to weigh in on the proper evaluation criteria once the broad goals have been agreed upon. We have provided some preliminary thoughts below on the sub-questions based on the program goals as we see them. We also emphasize that care should be taken in basing program comparisons/evaluation solely on relative costs per hypothetical unit, as different program designs may have different quantifiable or unquantifiable benefits.

Q4a. What evaluation criteria should be used?

As provided in our response to Question 4, the proper evaluation criteria will depend on the program goals. From the perspective of the goals that we identified in Question 1, cost per unit of carbon displaced and the cost per kWh provide similar information in terms of the effect that the incentive has on avoiding generation from fossil fuels. Of these, our preference would be for evaluations to take place per unit of carbon displaced, though arriving at this figure is potentially more complicated than a cost-per-kWh calculation. The Commission should also consider other avoided emissions, such as criteria pollutants, in devising evaluation criteria.

Apart from emissions criteria, programs should also be evaluated based on how well they support geographic and demographic diversity of participants and how well they support a "sustainable" solar industry within the state of Oregon. The latter may be best evaluated in a qualitative rather than a quantitative manner.

Q4b. How can the evaluation criteria be selected so that different programs are compared on an apples-to-apples basis?

One chief challenge in conducting "apples to apples" comparisons among programs is ensuring that the same data is collected for all programs and that the collection protocol is defined such that those providing the information do so in a consistent manner. For example, one consumer or solar provider may interpret "installed costs" to mean something different than another, rendering even an apples-to-apples comparison akin to analyzing apple prices without knowing whether the reported price is for a Red Delicious apple, a Fuji apple, or some other variety. In this respect, the primary issue is reporting consistency, which can largely be remedied by defining the parameters for data requests in sufficient detail.

A further challenge will likely arise if programs that act in concert with one another are evaluated individually rather than as a collective whole. For some of the potential metrics identified in the list of questions, this is not a significant concern. For instance, the cost of an incentive per kWh of generation or per installed watt can be evaluated on a program-specific basis, because that cost remains wholly specific to that program. On the other hand, outcome-based metrics such as units of carbon displaced require that each individual contributor be assigned its fair portion of the outcome. In other words, how much did net metering, a state tax credit, and an Energy Trust incentive individually contribute to that unit of carbon displacement? Such parsing is unnecessary and needlessly complicated, therefore we suggest that outcome-based metrics be calculated only in reference to incentive system as a whole rather than its individual components. The same rationale should apply beyond the carbon displacement example above to other potential outcome metrics such as jobs created, reductions in soft costs, or other environmental benefits.

Q4c. What data is needed and how should it be gathered?

Without a definitive determination of what the evaluation criteria are to be, it is difficult to respond to questions about how the necessary data should be gathered. We suggest that consideration of data needs be deferred until a clearer context exists for what that data will be measuring. We expect that, should disagreements arise on evaluation protocols, they will arise in the choice of those protocols rather that the data needed to measure them. Our suggested primary criteria would require information on estimated average electricity generation from individual systems and location or utility service territory. Evaluating participant demographics and industry sustainability would obviously require different types of data, but we would prefer to defer a lengthy discussion of those needs until it becomes necessary due to their selection as evaluation criteria.

Q5. In UM 1559, the Commission chose not to require utilities to report certain elements of Resource Value, such as avoided CO_2, fuel price volatility, integration, and transmission and distribution costs. Should we calculate them now? If so, how should we do so with the data available?

Docket UM 1559 explored some of the costs and benefits associated with distributed solar, but the investigation was not sufficient to quantify the full solar resource value. Other factors not considered in UM 1559 could be very relevant to policy makers. We recommend that the Commission undertake the valuable task of quantifying these benefits so that the value of solar incentive programs can be better understood by state policy makers. Elements to consider include:

- Economic development;
- The avoided cost of purchased power, generation, generating capacity, transmission and distribution capacity, and transmission and distribution losses;
- The environmental value of on-site generation compared to the utility's generation facilities; and
- The long-term resource value, taking into account the full life of the system and its benefits.

We recommend that the Commission follow the guidance of the recently-published IREC report entitled *A Regulator's Guidebook: Calculating the Benefits and Costs of Distributed Solar Generation.* The report suggests standardized approaches for measuring the various benefits and costs and explains how to calculate them regardless of the structure of the program or rate in which this valuation is used.[5]

Solar resource value quantification can be done professionally and efficiently by experienced outside consultants. Outside consulting assistance is likely to be necessary if the Commission, utilities, and other stakeholders are to have a meaningful and useful solar resource value study to ground future policy conversations. Sierra Club stands ready to work with the Commission, utilities, and other stakeholders to find creative measures to design and fund such a study.

[5] Jason Keyes and Karl Rabago, *A Regulator's Guidebook: Calculating the Benefits and Costs of Distributed Solar Generation* (Interstate Renewable Energy Council, Inc.), October 2013, *available at* http://www.irecusa.org/wp-content/uploads/2013/10/IREC_Rabago_Regulators-Guidebook-to-Assessing-Benefits-and-Costs-of-DSG.pdf.

Q6. How does the resource value of distribution solar compare with utility-scale solar? To make this comparison, what factors do we take into account, and what data would be needed?

The value of distributed solar differs from the value of utility-scale solar in several ways. Though the environmental benefits are similar, utility-scale solar does not necessarily exhibit the benefits of reducing or avoiding the costs of transmission and distribution capacity additions, or avoiding transmission and distribution losses. On the other hand, utility-scale solar generally costs less on a per-kilowatt basis, so the environmental benefits come at a lower cost. Both types of systems have a place on the grid and should be considered in utility and Commission plans. However, in doing so, we advise the Commission to weigh the differences between distributed solar and utility solar that stretch beyond the resource value, as elaborated upon in our response to Question 7.

Q7. How does cost effectiveness match up with the overall goal of promoting solar energy in Question 1?

The term "cost effectiveness" is generally used to refer to an analysis that compares costs to outcomes for two or more actions. This type of analysis provides a basis for comparing scenarios with similar types of outcomes but does not attempt to measure how hypothetical costs relate to the resulting benefits. While we realize that the term "cost effective" is used at one point in the language of enacted H.B. 2893, we are concerned that in the present context, its use departs from the statute, which seeks to investigate both costs and benefits from the perspective of retail electric consumers. This could be a simple terminology issue, but in this case we believe that the terminology is important in defining the meaning of the question. Consequently, we will respond to the question as though it were worded to request comments on how the "costs and benefits match up with the overall goal of promoting solar energy in Question 1," which we believe better represents the language and intent of the underlying law.

As we provided in our response to Question 1, there are numerous public policy objectives that solar is well suited to address, rather than a single primary goal. At this point in time, the costs are essentially limited to the cost of incentives, as Oregon is far from approaching the level of solar grid penetration where integration costs become an issue. A portion of the benefits is embodied in the resource value of solar, as addressed in Questions 5 and 6. However, the resource value of solar is supplemented by other societal benefits that should be considered as well. While this investigation is defined by language that refers to electricity ratepayers rather than to society as a whole, we would argue that for the most part, the two are one and the same.

Consequently, we urge the Commission to consider beneficial aspects of solar development such as local job creation, tax base enhancement, and health benefits as it considers how solar development affects Oregon citizens and ratepayers. The aforementioned *Regulator's Guidebook* contains a detailed discussion of why it is appropriate to include societal benefits in a value of solar analysis.

Separately, when considering the merits of rooftop solar in comparison to utility-scale solar projects (which some may still constitute distributed generation), we urge the Commission to extend its consideration beyond technical resource value to include other factors that differentiate the two. Most specifically, we refer to the detrimental effects that utility-scale solar development can have on natural and open spaces in the form of forest destruction, open space appropriation, habitat disruption and destruction, and erosion and stream sedimentation increases. While these impacts can prove difficult to reliably quantify and monetize, they do exist and should be assessed, at a minimum, on a qualitative level. Land-use and environmental effects need to be weighed against the fact that solar applications can be readily integrated into the built environment, and in some cases may in fact improve a structure's function (e.g., solar carports or awnings that provide shading).

To summarize, testing the cost-effectiveness of different incentive scenarios against a limiting metric such as cost-per-MWh of generation is an inadequate basis for arriving at an accurate assessment of the costs and benefits of promoting solar. Any such assessment should either test each scenario against a complete set of preferred goals or use a cost-benefit approach from a societal perspective.

Q8. How are the benefits of incentive programs distributed among non-participating retail customers?

As discussed in Question 7, there are numerous benefits of solar incentive programs that accrue to all ratepayers and citizens, though perhaps not in an entirely homogenous fashion. For instance, while the benefits of foregone carbon emissions can be considered more or less evenly dispersed, the health benefits of foregone emissions of other pollutants, such as particulate matter, will be most heavily felt near emission sources. Likewise, economic development benefits will vary based on how evenly development takes place throughout the state. In this respect, pursuing a model focused on truly distributed rooftop solar will cause the benefits to be more evenly dispersed than a model that relies on utility-scale development.

It can also be expected that the resource value of solar will be different in distinct locations and utility service territories. These benefits can be seen as accruing to all of the customers of a given distribution utility, though there could be circumstances where benefits are distributed across a wider area. One example of this would be the suppression of peak power prices on a regional basis, due to the effects of both solar generation itself and reduced lines losses. Ultimately, it is not possible to say precisely where and to what degree these effects will exist without a detailed analysis, but again we would urge the Commission to consult the *Regulator's Guidebook* for expert guidance on the topic. As with utility ratemakings, both the costs and benefits will be socialized to some degree, and no two consumers will experience precisely the same costs or benefits.

Q9. Can those benefits be quantified? If so, how? What studies would need to be done and what data would be needed?

At the outset, Sierra Club asserts that the benefits of solar generation generally, and distributed solar generation in particular, are absolutely capable of reliable quantification. As a first layer of readily-quantifiable benefits, the operational characteristics of solar, like any generation resource, can be quantified into an "avoided cost" value that represents the costs that a utility would have incurred to generate the same kWh in absence of the solar resource. While the avoided cost concept has historically been fairly constricted in its application, in that solar resources have typically been valued merely at the energy and capacity value of centralized, fossil-fired generation, there are many more costs/values that may be considered and quantified consistent with an avoided cost approach. These resource- and location-specific benefits can be added on as a second layer of grid-related benefits. Sierra Club strongly recommends the *Regulator's Guidebook* as a resource for considering the types of benefits to quantify and the data needed to make value determinations related to the costs that distributed solar generation can enable a utility to avoid and the grid-related benefits that it can provide.

Sierra Club recommends a fresh look at the avoided cost of distributed solar generation to account for its specific operational benefits, but notes that this can be done without necessarily re-inventing the wheel. According to FERC regulations and precedent, a generation resource that is a qualifying facility(QF) is entitled **full avoided cost** if it chooses to take advantage of the federally-guaranteed obligation that an interconnected utility must purchase its output. While energy and capacity are key components of avoided cost, FERC has recently clarified that avoided cost may include other considerations, including but not limited to resource specific procurement requirements (e.g., a solar specific carve out within a state's RPS), any actual environmental costs that a QF allows the utility to avoid, and any transmission or distribution costs that the QF would allow the utility to avoid.[6]

Thus, the existing avoided cost concept can be adapted to capture the "distributed" values of distributed generation, including scalability of these resources which would allow a utility to avoid "lumpy" capacity additions from central generation plants and the ability to defer or avoid distribution or transmission upgrades. Importantly, FERC has recognized that these resource- and location-specific benefits of DG are already contemplated by existing law as quantifiable elements of utility avoided cost.[7]

Accordingly, by starting from a familiar framework, the grid benefits of distributed solar generation can be obtained using utility cost of service data and by building off of the data currently used to determine avoided cost. Even if the types of data are not already provided in avoided cost proceedings, PURPA provides the state regulatory authority charged with implementing PURPA wide discretion to require the types of information required to determine additional elements of avoided costs.[8] Sierra Club suggests that much of the data necessary to properly quantify the grid benefits of distributed solar generation is already available or could be made available by data request to the utilities.

Second, Sierra Club would recommend a study of societal benefits associated with distributed solar generation, which would include public health benefits of reducing emissions from fossil-fired plants, increased tax revenue from increased economic activity and job creation, and reduced use of water in the generation process, among others. For quantifying societal benefits, Sierra Club believes that those benefits are certainly capable of quantification and monetization, but acknowledges that more work will need to be done to identify data sources within Oregon that are robust enough to support a statewide, comprehensive examination. Sierra Club encourages the Commission to leverage sources of public health, economic, and demographic data that are available from state and federal government agencies, as well as accepted methodologies that have been used by those agencies previously to monetize societal benefits. At a minimum, Sierra Club suggests that a study of the societal benefits should consider and attempt to monetize the following benefit categories:

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[6] *California Public Utilities Commission*, Order Denying Rehearing, 134 FERC 61,044 (2011). *See also*, *Unlocking DG Value: A PURPA-Based Approach to State Policy Design* (IREC), January 2013, *available at* www.irecusa.org/wp-content/uploads/2013/05/Unlocking-DG-Value.pdf.

[7] *See* 18 C.F.R. § 292.304(e)(2)(vii).

[8] 18 C.F.R. 292.302(d).

- Economic effects of increased solar market activity, including job creation and downstream effects on related industries/activities;
- Ability of program to leverage private capital and federal tax incentives to create local benefits;
- The stimulative effect of increasing the discretionary spending of customers through bill savings realized from installing onsite solar;
- Avoided morbidity and mortality associated with emissions from the fossil-fuel generation fleet;
- Reduced GHG emissions and mitigation of climate change-related impacts;
- Reduced reliance on water resources for thermal generation process; and
- Avoided land use impacts of distributed solar.

Q10. What available studies on benefits of SPV (national or from other states) might be applicable to Oregon, and how would the results be adjusted so that the dollar value of the benefits is realistic for Oregon?

If the Commission were seeking information on solar benefit studies just five years ago, those studies could be counted on one hand. Today, there is a growing body of cost-benefit studies and literature focused on solar generation resources, with several more studies expected over the next year. Oregon has the benefit of reviewing what has worked and what has failed in these studies, and can use the emerging consensus regarding the types of benefits that solar generation delivers to inform its own study.

Unfortunately, Oregon is unlikely to be able to draw any meaningful conclusions regarding the value of solar in Oregon based solely on the previous work done in other jurisdictions and we do not discuss those absolute values here. Rather, of greater importance is the fact that although the <u>**types**</u> of benefits that solar provides should be nearly the same everywhere, there is no universally accepted standardized methodology for determining the value of solar. Accordingly, it is important for the decision-makers in each instance to oversee the development of a methodology to ensure that the baked-in assumptions are consistent with state policy objectives and planning horizons and national best practices in valuing generation resources. There is an emerging consensus regarding the types of benefits that solar can provide, as well as a general understanding that the <u>**actual value**</u> of each of those benefits will depend on regional or utility-specific inputs. Thus, Oregon may be able to derive "ballpark" values by looking to existing studies as references, but Sierra Club believes that such rough approximations would be inadequate to support public policy decisions and could prove to be a distraction.

Given the growing number of solar studies, Sierra Club would recommend that the Commission review several recent papers that provide an overview of cost-benefit studies. Among these papers, the *Regulator's Guidebook* highlights the importance of having the Commission participate in choosing methodological assumptions and not delegating that task to parties with their own natural biases. In addition, we recommend that the Commission review the Rocky Mountain Institute's (RMI) recently published meta-study of sixteen recent regional or utility-specific distributed solar generation studies.[9] The RMI report provides a survey of some of the values determined in these studies, further revealing a

[9] *A Review of Solar PV Benefit & Cost Studies* (RMI 2013 Study"), July 2013, *available at* http://www.rmi.org/elab_empower.

diversity of results based on different methodological assumptions. Another publication of value on this topic is *A Generalized Approach to Assessing the Rate Impacts of Net Energy Metering*, which discusses methodological approaches to assessing the cost-effectiveness of net metering programs and evaluates the approaches taken by a 2006 study in Austin, Texas, and two 2009 studies conducted in both Arizona and California.[10] The *Generalized Approach* paper discusses several of the methodological flaws in these early studies, but also provides a good discussion of the types of benefits that should be considered for solar resources. Sierra Club suggests that the Commission use these resources to learn from the mistakes made by other jurisdictions.

Q11. Do incentive programs create cross subsidies?

An incentive or any program can create a subsidy if the benefits approximately balance out the costs. If benefits created by program participants exceed the costs, and those benefits are enjoyed by non-participants, then it could be said that the subsidy flows in the direction of non-participants. If, on the other hand, participating customers receive benefits in excess of the value they create, then the subsidy could be said to flow in favor of participants, imposing net costs on non-participants. Given the complexity of making this determination, Sierra Club cautions against including net metering within the category of programs that "create cross subsidies". Without a comprehensive cost-benefit study, that presumption should be avoided. Sierra Club suggests that it is quite possible that net metering provides net benefits once the benefit categories are set and properly assessed.

Q11a. Who pays them?

In most cases, utility-administered direct incentives are funded by utility ratepayers through public purpose charges or other similar rate components. In the case of programs that may cause a utility to fall short of collecting its full revenue requirement—including demand-side programs that reduce kWh sales to the utility—a utility may attempt make up any shortfall in revenue the next general rate case or through some Commission-approved adjustment clause to recover identified lost revenue more quickly. The method that is used to collect these revenues (i.e., either through a volumetric rate component or through a fixed per customer charge) can affect the extent to which certain customer groups shoulder the burden of a subsidy.

Q11b. Are some ratepayer classes more affected than others?

In the context of electric rate setting, the mechanism of the cross-subsidy can impact which customers are most affected. There may be structural subsidies among rate classes, depending how revenue allocation is accomplished. If a revenue requirement shortfall that is due primarily to the activities of one rate class is allocated to all rate classes in a general rate case proceeding, there may be an interclass subsidy. Sierra Club would note that where such interclass cost shifts are possible, they are not inevitable and can be balanced in the ratemaking process with other policy priorities. In other words, it would be wrong to start with the premise that incentives naturally create a subsidy that is spread among classes.

[10] Jason Keyes and Joseph Wiedman, *A Generalized Approach to Assessing the Rate Impacts of Net Energy Metering* (Solar America Board of Codes and Standards), January 2012, *available at* www.solarabcs.org/about/publications/reports/rateimpact.

Q11c. How are low-income ratepayers protected?

Sierra Club understands that equity is a core concern in balancing the policy benefits of an incentive program against the potential negative impacts on those who bear the economic burden. The relative impact on particular groups of how a subsidy is recovered can depend on the mechanism used to recover it. If the subsidy is embedded in volumetric rate components, then it could be said that customers with higher usage carry a higher proportion of the subsidy. To the extent there is a correlation between high income and high usage of electricity (assuming larger homes with more amenities and appliances consuming electricity), it might be the case that low income/low usage customers do not carry a disproportionate share of this intra-class subsidy.

On the other hand, a subsidy that is collected through a per customer account surcharge would be unavoidable and could result in low-usage customers bearing a higher proportion of the costs than would be the case under a volumetric collection of that subsidy.

Sierra Club would add, however, that given the relatively modest size of incentive programs, the impacts on low-income customers should be de minimis. Understanding that a criticism of incentives for solar PV is that low-income customers are often unable to enjoy the benefits because they lack the resources to install, or do not own their dwelling, Sierra Club notes that a number of creative opportunities exist to enable low-income customers to enjoy the benefits of solar. One way is through shared solar, which could be provided and targeted at this group through income-based eligibility requirements and could provide bill savings by allowing these customers to receive bill credits from the output of these shared systems.

Q11d. Do some types of programs create less of a cross subsidy than others?

It is erroneous to begin with the assumption that incentive programs create a subsidy before first ascertaining the relative benefits and costs of the program. Indeed, programs like net metering are capable of delivering direct net benefits to non-participating customers. While it is impossible to answer this type of general question without quantitative data on particular programs, Sierra Club believes that it is important to point out that some programs are capable of providing net benefits and may not impose a cross subsidy at all.

Q12. Do VIR and Net Metering participants pay their full share of the fixed costs of maintaining the grid? How are fixed costs recovered, and how should they be recovered?

Sierra Club cannot credibly answer this question without, again, having quantitative data regarding the full cost of service for customers participating in net metering or receiving VIR payments and the amount of revenue still collected from those customers net of bill credits or payments. Generally, if a customer is offsetting substantial amounts of grid consumption with onsite generation but still remits sufficient payments to the utility to cover the costs of providing service, that customer should be considered to be paying his fair share.

It is important to consider, in this respect, that net-metered customers can have a lower cost of service than similarly situated customers without onsite generation, since the utility's marginal costs will be different given the differences the differences in consumption profiles for net usage by virtue of onsite generation. California's recent net metering study shows that net-metered customers, taken as a whole, continue to pay enough to the utilities to cover the utilities' full costs of providing service to net-metered customers.[11] If a similar study were undertaken in Oregon, it might discovered that customers who participate in VIR or net metering still pay their fair share of the cost of service.

Q13. At what level of penetration does the impact on utility revenue become a significant factor?

Sierra Club is not aware of any utility in the nation, including high-penetration solar markets, that is facing significant financial consequences as a result of distributed solar generation. As discussed above, if there is a shortfall in the revenue requirement, utilities are usually able to recover that shortfall through either a true-up process or through a general rate case proceeding. In those circumstances it is non-participants that would bear the risk of lost revenue, and the utility would ultimately recover its required revenue without downgrading its credit or upsetting its shareholders.

Ultimately, Sierra Club does not see a direct or imminent threat to the utility business model from the continued growth of solar, but notes that this has been a hot topic in 2013. In fact, at the beginning of the year, the Edison Electric Institute (EEI)[12] published a widely read article warning that distributed solar generation has a potential to be a disruptive force that could threaten to upend the utility business model and lead to dire financial losses for utilities. While this is a thought-provoking and important article—and Sierra Club appreciates that the author's intent was to engage stakeholders in a discussion of what the utility of the future will look like—Sierra Club believes that the concerns of economic collapse are highly theoretical and do not provide cause for immediate concern or protectionist reaction.

For example, a central argument of the EEI paper is that increasing penetration of solar will cause non-participant rates to sky-rocket, as the costs of maintaining and operating the grid are spread out among fewer billing determinants. The paper theorizes that eventually this will lead to ratepayer revolt and could lead state commissions to provide ratepayers relief (under political pressure), leaving the utility with the stranded cost of redundant generation capacity. This, theoretically, could cause shareholder losses, credit downgrades, and an increase in the cost of capital.

Sierra Club would like to point out that public opinion polling reveals that solar remains overwhelmingly popular, despite utility arguments that it causes a cost shift and exists as a subsidy. Ratepayer impacts remain quite modest, far short of the critical mass necessary to cause a widespread ratepayer revolt. For instance, California's recent cost-effectiveness study showed that a high penetration scenario of over 5.5 gigawatts of net-metered systems would impact just one percent of the overall revenue requirement.[13] It is hard to imagine that this impact would move the political needle enough to result in the type of regulatory treatment feared in the EEI report.

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[11] *California Net Energy Metering Evaluation* (Energy and Environmental Economics, Inc.), at p. 101, October 2013, *available at* www.cpuc.ca.gov/NR/rdonlyres/75573B69-D5C8-45D3-BE22-3074EAB16D87/0/NEMReport.pdf.
[12] Peter Kind, *Disruptive Challenges: Financial Implications and Strategic Responses to a Changing Retail Electric Business*, January 2013, *available at* http://www.eei.org/ourissues/finance/Documents/disruptivechallenges.pdf.
[13] California E3 Study at p. 67.

Putting aside speculation of worst case scenarios, Sierra Club notes that fair and transparent rate design can provide a rationale check to ensure that the cost of maintaining and operating critical utility infrastructure will not become stranded and that utilities will not suffer significant financial consequences. On the utility's part, it is incumbent upon them to become far more proactive in resource planning to account for the demand for customer-sited generation. Prudent planning will help utilities harness the inevitable growth of distributed solar generation without unnecessarily locking horns with the solar industry and solar advocates in pitched battle at every turn. As discussed above, Sierra Club views the utility's role, ideally, as that of facilitator and partner to the development of distributed solar generation.

Q14. What are sources of forecasts of solar panel prices? How big is the range of estimates?

The installed cost of solar, including both hardware and soft costs, has gradually declined in recent years and is predicted to continue that trend. Greentech Media is the leading source of data on the current and forecasted price of solar modules. According to its 2013 Q2 report, module manufacturing costs are expected to decrease to $0.36/W by 2017, down from $0.50/W in Q4 of 2012. The decline is expected to occur due to advanced technology and automation in the manufacturing processes.[14] Assuming a 50 percent markup, this puts the 2017 wholesale price of solar at approximately $0.75/W by 2017.

The predicted decrease is somewhat slower than price trends during the past decade. For instance, the wholesale price for modules fell from $4.04/W in 2005 to $2.40/W in 2010, and the capacity-weighted installed cost average of residential and commercial PV system prices fell from $7.90/W to $6.20/W.[15] Median installed prices follow a similar trend, as seen in Figure 1 below. Most of the decrease in the installed cost of PV is attributable to falling module prices.[16]

[14] Rinaldi, Nicholas. *Solar PV Module Costs to Fall to 36 Cents per Watt by 2017.* 17 June 2013. http://www.greentechmedia.com/articles/read/solar-pv-module-costs-to-fall-to-36-cents-per-watt.
[15] Ardani, K., G. Barbose, R. Margolis, R. Wiser, D. Feldman, S. Ong. *Benchmarking Non-Hardware Balance of System (Soft) Costs for U.S. Photovoltaic Systems Using a Data-Driven Analysis from PV Installer Survey Results.* November 2012. http://emp.lbl.gov/sites/all/files/lbnl-5963e.pdf
[16] Barbose, G., N. Darghouth, S. Weaver, R. Wise. *Tracking the Sun VI: An Historical Summary of the Installed Price of Photovoltaics in the United States from 1998 to 2012.* July 2013. http://emp.lbl.gov/sites/all/files/lbnl-6350e.pdf

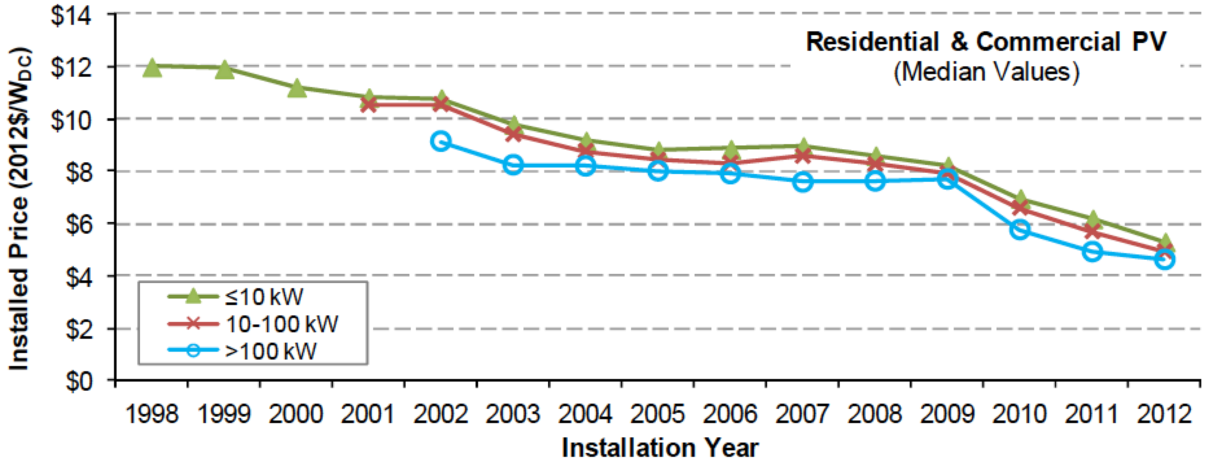

Figure 1: Installed Price of Residential and Commercial PV over time.[17]

We were unable to obtain forecast data that is specific to Oregon. Indeed, it is not clear to us that state-specific cost forecasts even exist, and if they do, they do not appear to be readily available. That said, the declining price of PV modules is both a global and national trend, indicating that hardware costs in Oregon will continue to decline in a corresponding manner. Soft costs, however, will decrease as a result of streamlined permitting and incentive application processes as well as decreased labor and marketing costs due to increased installation volume, all factors that the legislature and the Commission can and should strive to influence.

Q15. How much of SPV system costs are soft costs (interconnection, permitting, code compliance, other)?

In addition to demonstrating declining costs, the costs referenced above also demonstrate that soft costs are accounting for an increasing percentage of the installed cost of a system. Soft costs can vary widely by region or locality, reaching as high as 64% of the installed cost (Figure 2).[18] However, the variability in the installed cost is decreasing, reflecting that the maturing market is resulting in more standardized soft costs across the country.[19]

Hardware costs are a product of international markets and technology advancements - factors largely out of reach from the influence of the state. Thus, in order to continue to increase the cost-competitiveness of solar, focus must be placed on reducing the soft costs associated with PV installations. We recommend that the Commission focus on determining the volume of solar necessary to reduce business market costs (e.g., labor and marketing), determining the appropriate incentives necessary to reach that volume, and continuing to streamline interconnection, net metering, and incentive application processes in collaboration with the Energy Trust of Oregon.

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[17] Ibid.

[18] U.S. Department of Energy, Office of Energy Efficiency and Renewable Energy. *Reducing Non-Hardware Costs*, December 2013, *available at* http://www1.eere.energy.gov/solar/sunshot/nonhardware_costs.html.

[19] Barbose, G., N. Darghouth, S. Weaver, R. Wise, *Tracking the Sun VI: An Historical Summary of the Installed Price of Photovoltaics in the United States from 1998 to 2012*, July 2013, *available at* http://emp.lbl.gov/sites/all/files/lbnl-6350e.pdf.

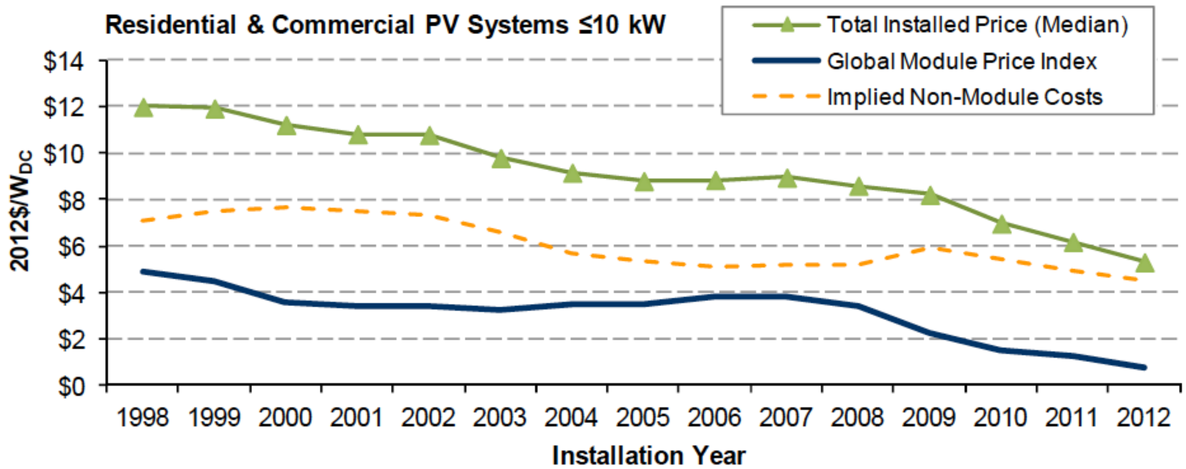

Figure 2: Installed Price, Module Price Index, and Implied Non-Module Costs over Time for Residential and Commercial PV Systems ≤ 10 kW[20]

Q.16 What initiatives are underway to lower soft costs? Is the trend in soft costs going down at the same pace as panel costs? Do soft costs create a "floor?"

There are several initiatives underway to reduce the various components of the soft costs of a system. Most notably, the Department of Energy's SunShot Initiative has a goal of decreasing total installed costs to $1.50/W for residential systems and $1.25/W for commercial systems by 2020, which would include reducing soft costs to $0.65/W for residential systems and $0.44/W for commercial systems.[21] The SunShot Initiative has many resources to assist local governments in decreasing the various components of soft costs.

Oregon has already taken some steps to reducing soft cost for solar through simplified permitting processes. Oregon has this opportunity because of the state's authority over local building code requirements. Oregon's statewide Solar Installation Specialty Code covers both technical requirements and application processes at the municipal level. The state has a specific website for solar building code information,[22] but still leaves most of the process of local permit processes up to the municipality.[23] In addition, The Energy Trust of Oregon has made significant advances in the solar market with its incentive and technical assistance programs.

We recommend that the Commission, the Energy Trust of Oregon, and the ODOE continue to streamline interconnection and permit applications and to make their administrative processes more transparent and efficient. In addition, the Commission should evaluate the solar market in the state to determine what

[20] Ibid.
[21] Ardani, K., G. Barbose, R. Margolis, R. Wiser, D. Feldman, S. Ong, *Benchmarking Non-Hardware Balance of System (Soft) Costs for U.S. Photovoltaic Systems Using a Data-Driven Analysis from PV Installer Survey Results*, November 2012, *available at* http://emp.lbl.gov/sites/all/files/lbnl-5963e.pdf.
[22] Oregon Building Codes Division, *Solar Code*, December 2013, *available at* http://www.cbs.state.or.us/bcd/programs/solar.html.
[23] Interstate Renewable Energy Council, *Sharing Success: Emerging Approaches to Efficient Rooftop Solar Permitting*, May 2012, *available at* http://www.irecusa.org/wp-content/uploads/Sharing-Success-final-version.pdf.

level of solar is necessary in order to realize the soft-cost reduction benefits that come with increased volume of solar, and incentivize the market such that it reaches that volume goal.

We also recommend that the Commission, the Energy Trust of Oregon, and the ODOE encourage local Solarize programs throughout the state. Solarize programs bring together groups of residential customer to purchase solar at a bulk rate from a participating solar company or companies. Such programs have shown the potential to play a major role in reducing customer acquisition costs, and have frequently resulted in significant discounts to participants. Solarize programs have been successful in Portland and across the country. Among the determining factors of the consumer discount realized is the scale of the program, such that programs with more participants experience greater discounts. This can have the effect of reducing the effectiveness of small programs, such as those sponsored by small local jurisdictions. Consequently, a larger program that brings together many smaller communities is likely to be more successful than smaller individual programs. The involvement of a state organizing entity could facilitate the creation of such a multi-jurisdictional program. The successful Solarize Massachusetts program could serve as a useful model in this respect.[24]

Q.17 List perceived barriers within the incentive programs in Oregon.

Some of the real and perceived barriers within the incentive programs in Oregon include:

- The lack of stability over time in the rates established for the VIR program leads to uncertainty for both installers and consumers.
- The elimination of the business energy tax credit in Oregon resulted in the inability for small businesses and non-profit organizations to finance and participate in Oregon's solar incentive programs.
- State tax incentives including the residential energy tax credit and former business energy tax credit are limited by the state's budget capacity and political will and do not enjoy an independent and stable source of funding.
- Oregon's incentive programs lack a clear target or goal for the quantity of solar installations the state wishes to achieve and therefore the incentive programs are not appropriately calibrated to reach such a goal. Similarly, Oregon's Renewable Portfolio Standard is less aggressive than some other states, which reduces the incentive for individual utilities to aggressively pursue increased renewable development as compared to states with more aggressive standards.

Q18. List "other" barriers unrelated to incentive programs (e.g. local permitting, building codes, other)

Other barriers unrelated to incentive programs that can be identified by the Sierra Club include:

- Sierra Club agrees that permitting, building codes and fire codes can be a barrier.
- Lack of market scale (to interest major TPO providers and competition)
- Lack of consumer/commercial financing options (i.e., Green Bank)

[24] Massachusetts Clean Energy Center, Solarize Mass, December 2013, *available at* http://www.masscec.com/solarizemass.

- Lack of group net metering reduces options for some consumers
- Low electric prices, lack of rate design that incentivizes conservation
- Complexity (i.e., multiple incentive programs)
- Low electricity rates in the Pacific Northwest due to the prevalence of hydropower on the grid make it more difficult to finance solar projects than in other areas of the country.

Q19. At what penetration does solar generation affect local distribution reliability?

The best metric for gauging the level of solar grid penetration that presents reliability and safety concerns are interconnection standards, which have been developed precisely with these issues in mind. Oregon currently utilizes a 15% of annual peak load screen for Level I and Level II interconnections, thus it seems safe to assume that the Commission is confident that this level of penetration presents no potential for problems.[25] We are unaware of any instances where a distribution circuit in Oregon has been closed to new interconnections or rendered unavailable for Level I or Level II interconnection review as a result of high solar penetration. Together, these indicators lead us to conclude that the issue of distribution grid reliability is adequately addressed by current standards, and at present does not constitute a barrier to new solar installations.

That said, it is our understanding that the peak load screens utilized in the interconnection standards of Oregon and other states were always intended as an imprecise way to address the real source of concern, that generation could exceed the minimum load on a distribution circuit. Lack of data on minimum loads prompted the use of assumptions about how minimum load would relate to peak load (at least 33%), the use of a safety margin (divide 33% by two) and some rounding, leading to the establishment of 15% of peak load as a commonly used screen. In reality, the level at which concerns should arise has always been, and remains, 100% of the minimum load on a circuit.

This screen has now become a supplemental metric in more recently adopted interconnection standards, including high solar penetration states such as California[26], and most recently by the Federal Energy Regulatory Commission (FERC)[27] and the state of Ohio.[28] Under a slightly different model, Hawaii, another high penetration solar state, has adopted a 50% of minimum load screen, but with minimum load determined in reference to the time a system is generating power (i.e., the daytime rather than nighttime for solar).[29] Under these recent adoptions, the initial peak load screen has been maintained, but projects that fail this screen may elect to proceed through a supplemental review process if they meet the 100% of minimum load screen, (or 50% of minimum load during operation hours in the case of Hawaii) and other

[25] Or. Admin. R. 860-039-0030 & 860-039-0030.

[26] CPUC Decision, Docket R11-09-011, Decision No. 12-09-018, *Decision Adopting Settlement Agreement Revising Distribution Level Interconnection Rules and Regulations – Electric Tariff Rule 21 and Granting Motions to Adopt the Utilities' Rule 21 Transition Plans,* September 20, 2012, *Available at* http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M028/K168/28168335.PDF

[27] FERC Order, RM13-2-000, Order 792, *Small Generator Interconnection Agreements and Procedures.* November 22, 2013.

[28] Finding and Order PUCO.Case No. 12-2051-EL-ORD, *Finding and Order: In the Matter of the Commission's Review of Chapter 4901:1-22, Ohio Administrative Code, Regarding Interconnection Services,* December 4, 2013, *available at* http://dis.puc.state.oh.us/TiffToPDf/A1001001A13L04B42903E62593.pdf

[29] Hawaiian Electric Company, *Rule Number 14, Revised Tariff Sheet 34D-17*, Effective December 3, 2011, *available at* http://www.heco.com/vcmcontent/FileScan/PDF/EnergyServices/Tarrifs/HECO/HECORules14.pdf

supplemental screens rather than proceed through a more time consuming and expensive interconnection study process. Again, the presumption is that projects which are compatible with this screen do not present a safety or reliability concerns, and as such may be interconnected without the need for a detailed interconnection study.

Q20. What initiatives are in place to prepare for greater solar penetration and what initiatives might be considered?

There are a number of ways in which Oregon might prepare for greater solar energy penetration, though at present solar energy production in Oregon is negligible compared to state generation portfolio. [30] [31] Therefore we would like to emphasize that while planning for the future and anticipating changes is a sound course of action, the idea that planning is warranted should not be used as a justification for slowing down the current trajectory of solar growth in Oregon. That rate of growth is clearly already slow in relation to that in many other states, and Oregon is far from the level of solar penetration that necessitates immediate action.

As part of the SunShot Initiative, the U.S. Department of Energy (DOE) has established the High Penetration Solar Portal, a source of technical information and guidance on integrating solar into the grid at high levels. The portal identifies a number of avenues to consider in high penetration solar scenarios, include modernizing the transmission and distribution systems, exploring the capabilities of improved PV system technologies, advancing solar resource modeling and analysis, and improving codes and standards. The Commission should consult the numerous technical resources and reports available through this portal for further information planning components and opportunities.[32]

Projects in a number of states are represented in this portal, but to our knowledge, the most significant state planning initiatives exist in California and Hawaii. Hawaii has a goal of meeting 40% of its energy needs with renewable energy by 2030. As part of the Hawaii Clean Energy Initiative, the Hawaii Solar Integration Study was released in 2013 detailing the technical effects of high penetration on generator operations. The study recommended several mitigation strategies for issues affecting grid reliability and curtailment, and concluded that high levels of variable renewables can be incorporated into the generation capacity without sacrificing reliability. Doing so requires changes to utility equipment and operating practices as well as to the capabilities of renewable generation equipment in support of grid operations. Among these are recommendations that variable generation equipment have the capability for inertial and frequency response, voltage and frequency ride-through, and to provide ancillary services.[33]

California has commissioned several reports and studies related to the integration of DG and renewables into the grid. Navigant Consulting and SCE released a study in 2012 establishing guiding principles and

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[30] U.S. Energy Information Administration, *State Renewable Electricity Profiles: Oregon*, March 8, 2012, *available at* http://www.eia.gov/renewable/state/oregon/.
[31] U.S. Energy Information Administration, *Electricity Power Monthly*, November 20, 2013, *available at* http://www.eia.gov/electricity/monthly/epm_table_grapher.cfm?t=epmt_1_20_a.
[32] U.S. DOE, *Sunshot Initiative High Penetration Solar Portal*, December 2013, *available at* https://solarhighpen.energy.gov/home.
[33] National Renewable Energy Laboratory, *Hawaii Solar Integration Study: Executive Summary*, June 2013, *available at* http://www.nrel.gov/docs/fy13osti/57215.pdf.

assumptions to apply to SCE's system to better understand the cost and impact of high levels of DG integration. The framework is designed to be applicable to other California electric utility distribution systems as well. In addition, the study proposed that the costs and impacts of increased DG could be reduced by guiding projects to locations on the grid that can better accommodate such systems.[34]

Building upon that framework, the California Energy Commission (CEC) and Navigant Consulting released a follow-up study in 2013, analyzing the cost impacts associated with increased DG. Among other things, the study found that DG has more significant impacts on the grid when it is clustered rather than distributed among many feeders across the system, and that the impact of a DG system depends on the type and voltage of a feeder, as well as the location of the system along that feeder. The study noted that advanced communications, automated controls, changes to design standards, operating practices, and maintenances, and new regulatory frameworks may be necessary to achieve the state's DG targets.[35]

We urge the Commission to examine the methodologies and findings of these and other studies and reports available through the DOE portal to guide its own planning activities for higher penetration solar in order to recognize potential issues and identify mitigation strategies. We also make the specific suggestion that the Commission seek information from utilities on the availability of minimum load data and/or their capabilities for assembling it if and when the need arises. As mentioned in question 19, it has historically been difficult to utilize minimum feeder loads as interconnection screens due to the lack of data on minimum loads. In anticipation that a minimum load screen may eventually become part of Oregon's interconnection standards, this seems a reasonable first step in ensuring that it could be implemented if adopted.

Q21. Looking forward, what initiatives are in place to reduce solar integration costs, and what initiatives should be considered?

As in our response to question 21, we urge the Commission to consult the DOE High Penetration Solar Portal and California and Hawaii studies for information on both high penetration costs and potential solutions. To a large degree, the identification of those costs is a topic that falls very much in line with suggestions for solutions. Among those topic areas which might be identified as "solutions" are improvements in the technical capability of solar systems to activate grid support services, modeling improvements that reduce availability uncertainty, and modifications to the electric grid itself that improve its ability to better integrate solar resources, but that also have other significant reliability benefits and applications (e.g., advanced communications and control systems). We support the Commission in its desire to consider such improvements, but again wish to emphasize that high penetration solar integration costs are very much a longer-term issue and correspondingly suggest that the more pressing issue is improving industry growth. Planning is wise, but we should not let problems that do not yet exist distract our attention from solving those that clearly do.

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[34]Southern California Edison, *The Impact of Localized Energy Resources on Southern California Edison's Transmission and Distribution System,* May 2012, *available at* http://www.energy.ca.gov/2013_energypolicy/documents/2013-08-22_workshop/SCE_Local_Energy_Resources_Study.pdf.

[35] Navigant Consulting, *Distributed Generation Integration Cost Study: Analytical Framework*, November 2013, *available at* http://www.energy.ca.gov/2013publications/CEC-200-2013-007/CEC-200-2013-007.pdf.

Q22. What business models would best meet the overall goals in Questions 1 and 2?

No single business model can be effective in supporting solar in comprehensive manner. We recommend that Oregon consider all business models, including utility solar, third-party ownership, customer-owned, and shared solar as worthy components of an overall state solar incentive framework. A diversity of development and consumer options are the best path to an even distribution of costs and benefits. Having said that, we believe that distributed rooftop generation is generally preferable to utility-scale development due in part to the land-use and other issues likely to be present with utility-scale development. However, we do believe that utility-scale generation has a place on already disturbed, and often underutilized, parcels of land such as brownfields and closed landfills. There may also be circumstances where centralized projects that support other valuable goals are worthwhile, provided they are sited, constructed, and operated in an environmentally conscious manner.

RESPECTFULLY SUBMITTED this 18th day of December, 2013.

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UM 1673–CERTIFICATE OF SERVICE

I hereby certify that I have this day caused Comments from the Sierra Club in response to Staff Questions for Parties on Solar Incentive Program Report under HB 2893 to be served by electronic mail to those parties whose email addresses appear on the attached service list, and by First Class Mail, postage prepaid and properly addressed, to those parties on the service list who have not waived paper service from OPUC Docket No. UM 1673.

DATED this 18th day of December, 2013.

Respectfully submitted,

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eDockets

Docket Summary Return to Search Page eFiling

Docket No: UM 1673 **Docket Name:** PUC LEGISLATIVE REPORT TO COMPLY WITH HB 2893 SOLAR INCENTIVES

Print Summary

In the Matter of PUBLIC UTILITY COMMISSION OF OREGON, Report to the Legislature on Effectiveness of Incentive Programs for Solar Photovoltaic Energy. Docket opened by HB 2893. Copy and paste link below into...

Filing Date: 9/23/2013

Case Manager: Adam Bless **Phone:** 503-378-6638 **Email:** adam.bless@state.or.us.

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