JOHN R. KROGER
Attorney General

MARY H. WILLIAMS
Deputy Attorney General

DEPARTMENT OF JUSTICE
GENERAL COUNSEL DIVISION

February 17, 2010

Filing Center
Public Utility Commission of Oregon
550 Capital Street, NE
Suite 215
Salem, Oregon 97308-2148

Re: AR 538/UM 1452;
In the Matters 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 (UM 1452) and a Rulemaking Regarding Solar Photovoltaic Energy Systems (AR 538)

Dear Filing Center:

Enclosed for filing are replacement originals and copies of Staff Final Comments in UM 1452 and AR 538, filed on February 12, 2010. The Staff Final Comments in these dockets omitted a signature. These originals and copies include a signature.

These documents have been served on UM 1452 parties. Electronic copies of these documents have been sent to AR 538 parties.

Thank you for your attention.

Very truly yours,

Stephanie S. Andrus
Assistant Attorney General
Of Counsel for Staff of
Public Utility Commission of Oregon

Enc.
c. UM 1452/AR 538 Service List

1162 Court Street NE, Salem, OR 97301-4096
Telephone: (503) 947-4789 Fax: (503) 378-5300 TTY: (800) 735-2900 www.doj.state.or.us

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UM 1452 and AR 538

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.	STAFF FINAL COMMENTS

I. Introduction.

House Bill 3039 ("HB 3039") mandates Volumetric Incentive Rate Pilot Programs ("pilots", "VIR Pilot Programs"), for each electric company doing business in Oregon to demonstrate the use and effectiveness of volumetric incentive rates ("VIR"). HB 3039 also creates a Solar Capacity Standard ("SCS") under which each of Oregon's three investor-owned utilities must acquire a share of 20 MW's of nameplate capacity from solar photovoltaic energy systems by 2020.

Parties filed opening comments in UM 1452 and AR 538 on January 14, 2010. Staff's Opening Comments incorporated feedback from five Staff-facilitated workshops held between September 30, 2009 and January 6, 2010, and rested heavily on recommendations from the Oregon Department of Justice (DOJ) as how best to address jurisdictional limitations on the Commission's ability to establish VIR in the pilot programs.[1] Staff's Opening Comments included Staff's proposal for the design of the VIR Pilot Programs, proposed rules to implement the pilots and SCS, and documents showing Staff's approach to establishing VIR. Staff's Opening Comments explained design elements of the VIR Pilot Programs and recommended changes from a previously-published Straw Proposal.[2]

Staff makes final recommendations to implement HB 3039 in these Final Comments and attached draft of proposed rules. (Attachment A.)

II. Staff responses to questions presented in the Commission's January 22, 2010 ruling.

1. **Bidding: If the Commission requires bidding, how should it structure the bidding process for efficiency and effectiveness? What, if anything, should it include in the rules (docket AR 538) or in the UM 1452 order on the bidding process?**

[1] A December 15, 2009, Memorandum from the DOJ included the DOJ's analysis of the impact of federal legislation giving FERC exclusive jurisdiction over wholesale sales of energy in interstate commerce and some recommendations on how to implement HB 3039. The memorandum was distributed to parties.

[2] Staff created the Straw Proposal, filed December 4, 2009, to facilitate discussions regarding VIR Pilot Program design and rules to implement the pilots.

The Commission should require bidding for large-scale systems (between 101 and 500 kW), but not for small- and medium-scale systems. A primary advantage of the VIR option, compared to the VIR net-metering option, is that VIR payments are not limited to annual customer usage. The usage constraint associated with the VIR net-metering could become a barrier to development of large systems. The VIR bid option removes this constraint and the potential unintended incentive to increase usage.

Business consumers interested in developing large solar PV systems likely have experience participating in competitive solicitations and should be capable of managing the complexity and cost of the bidding process. However, for those consumers installing small- and medium-scale systems, the complexity and cost of the bidding process could become a barrier to participation in the VIR Pilot Programs. For these reasons, the Commission should use the bidding VIR solely for large systems.

The Commission should structure the VIR bid option as a price-based request for proposals ("RFP") process. Each utility should solicit proposals to achieve their annual allocated capacity for large-scale systems. Consumers interested in developing large-scale systems should bid their required fixed VIR payment. The electric companies should score the bids primarily on price and not adjust for non-price factors such as location. The utilities should rank the VIR bids from lowest to highest. Bid selection should start with the lowest-bid VIR and continue until the addition of a bid would cause the cumulative capacity of selected bids to exceed the amount of capacity targeted in the request for proposals. Winning bids should be paid their fixed bid for a term of 15 years.

Staff recommends that the Commission adopt proposed OAR 860-084-0100 and OAR 860-084-0365 to implement Staff's VIR bid option and adopt Staff's proposed RFP process by order. Staff also recommends that the Commission order utilities to file draft RFP's for solar PV capacity for Commission approval no later than 30 days after the final order in Docket UM 1452.

2. Utility and Affiliate Ownership: Should the Commission allow utilities or their affiliates to own and operate eligible projects as qualifying third parties? If so, how would it work? How would the Commission address issues of payment, ratemaking treatment, etc?

The Commission should prohibit utilities and their affiliates from owning or operating eligible projects and from becoming assignees of VIR payments because the additional program and regulatory process complexity required by utility or affiliate ownership is not warranted given the limited time and the limited capacity deployed under the pilots.

3. Net metering incentives*:* Some parties are concerned about the perverse incentive for owners to waste energy under the net metering approach. Is this a problem? If so, how should the Commission address it (if the net metering approach is adopted)? Can (and should) the Commission limit the size of the system installed relative to the consumer's usage?

The VIR net-metering option could create a perverse incentive for owners to waste energy and a disincentive to improve energy efficiency. Owners of large-scale systems are most at risk because they would be more likely than owners of medium- and small-scale systems to generate more energy than they can consume in the ordinary course of business. Accordingly, Staff does not recommend the VIR net-metering option participants with large-scale systems.

With respect to the VIR net-metering option for medium- and small-scale systems, Staff recommends that the Commission limit the size of systems that may be installed by retail electricity consumers. Staff recommends that the Commission adopt rules requiring that (1) the estimated output of qualifying systems under the VIR net-metering option be no more than 90% of the rolling average of the retail electricity consumer's previous three year's of usage,; and (2) VIR net-metering participants certify that their systems meet this requirement in the standard contracts.

4. Market Rate Authority: How difficult is it for small project owners to obtain FERC market rate authority? How viable are other options for project owners (such as the Commission obtaining blanket authority for all participants)?

The process for obtaining market-based rate authorization ("MBRA") is explained on the Federal Energy Regulatory Commission's ("FERC's") website. An applicant must first obtain a docket number from FERC (electronically) and then file an application that includes 1) a transmittal letter; 2) contact information; 3) names and addresses of those served with the application; 4) description of services to be offered under market-base rate tariff; 5) description of applicant's business activities; 6) description of the business activities of applicant's affiliates or a statement that the applicant has no affiliates; 7) representations of how the applicant satisfies FERCs concerns regarding horizontal market power; 8) representations of how the applicant satisfies FERC's concerns regarding vertical market power; 9) any requests for waivers or authorizations; 10) a FERC Electric Tariff; and 10) an appendix listing the applicant's generation and transmission assets. (*See* Attachment 1; Print-out of Webpage re: "How to Get [MBRA] Authorization.")

FERC's website includes a sample application packet including a transmittal letter, petition for MBRA, asset list, and tariff. (Attachment 2; sample application). The petition for MBRA is for an Affiliated Generator Owner, but could be used for a generator that controls generating facilities rather than owns them. FERC's website includes sample worksheets ("screens") that each applicant must complete in connection with representations regarding vertical and horizontal market power. (Attachment 3: sample screens.) The information required by the screens includes the generator's capacity and that of affiliates, the extent to which the capacity is committed, and some information regarding reserve requirements and load within the Balancing Authority area.[3]

The sample petition includes bolded text specifying that an applicant will satisfy the Commission's concerns regarding vertical and horizontal market power if the applicant's entire capacity is less than 500 MW and committed under long-term contract and if any affiliates satisfy certain criteria. According to the bolded text, such an applicant may submit a "streamlined application."

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[3] A technical advisor at FERC stated that a MBRA applicant could obtain the Balancing Authority information from an annual report the Balancing Authority is required to file (Form 714), or by accessing information in a MBRA application filed by an entity within the applicant's Balancing Authority area. Also, the Commission could direct Staff to compile the necessary information regarding the Balancing Area on an annual basis and make it available to pilot program participants.

Finally, the FERC website also includes an electronic template for a FERC Electricity tariff that a participant could complete by filling in boxes. (Attachment 3; print out of electronic tariff template.)

There is a 21-day notice requirement for the MBRA and FERC Electricity tariff. Also, there is a 30-day notice period if the applicant asks for blanket approval under Part 34 of FERC's regulations of future issuances regarding securities and assumptions of liabilities. An applicant can ask that these notice periods be shortened. A technical advisor at FERC stated that FERC will typically act on a MBRA and accompanying tariff within three weeks of the expiration of the notice periods (at the expiration of 30 days). However, if the MBRA application has a material error, the applicant will be required to re-submit the application and the notice period will start over. Unless the error affects the request for blanket approval under Part 34, this notice period is 21 days.

Staff does not know whether a Commission request for MBRA for all pilot program participants would be successful. Such a motion has never been filed. Staff is aware of no mechanism to obtain MBRA for all pilot program participants with one application or petition.

5. Pilot Testing: What does the Commission need to do for an effective comparative assessment of the feed in tariff approach versus the current tax credit/subsidy approach? For example, how would one determine whether high/low participation in the pilot program vis-a-vis the current approach isn't simply a response to high or low volumetric incentive rates? Do the rules specify the right information to be collected for this analysis?

The Commission's primary tool to measure the effectiveness of the VIR Pilot Programs is data the utilities collect and provide to the Commission. The utilities will compile statistics showing the amount of capacity enrolled at each VIR. Further, Staff recommends that VIR Pilot Program participants be *required* to complete up to three surveys over the course of the pilots in order to receive VIR payments. (*See* Proposed OAR 860-084-0240(g).) These surveys can be designed to help the Commission determine which customers and customer segments are motivated by VIR, as opposed to existing incentives for the installation of SPV facilities.

Proposed rules require the utilities to compile specific data regarding each participant, *e.g,* nameplate capacity, location, date of enrollment, etc., which should help the Commission identify trends in VIR Pilot Program participation. The proposed rules do not define what information should be obtained through surveys but specify the surveys will be designed through a collaborative process. (*See* Proposed OAR 860-084-0440.) Staff's final proposed rule regarding survey design calls for the utilities to design the survey, or commission the Energy Trust of Oregon ("ETO") to design the surveys, and require that the utilities or ETO, if applicable, consult with the Commission and stakeholders before finalizing and distributing the surveys.

6. Carve outs and/or Rate Differentials: Should the Commission create "carve outs" and/or higher rate for non-profit organizations? For other groups? Why or why not?

The Commission should not create a rate carve out for any particular type of participant beyond what is recommended in Staff's proposal. Staff's proposal to differentiate between participants that install small-, medium-, and large-scale systems is based on expected participant costs and on estimates of the participants' market sophistication levels. Staff's rate proposal is sufficient to enable participation by a broad range of consumers.

Staff does recommend some special accommodation for non-profit organizations, however. The decentralized organization of many non-profits may put them at a disadvantage when it comes to competing in a capacity reservation open season. Entities with a more centralized management structure are likely to be better equipped to respond to changing market conditions and meet the application deadline associated with the open seasons. Accordingly, Staff recommends that the Commission order in UM 1452 that non-profit organizations may reserve capacity in the same manner as participants with small-scale systems (at any time); as long as the capacity of the organization's PV system does not exceed 100 kW.

The Commission should not create a carve-out or special rate for any other customer group.

7. Rate Calculations – methods and results: What explains the wide differences in the Matching Incentives approach versus the Cost Models Approach? What explains the wide differences in results for different cost models? What is the basis for the input assumptions used to estimate breakeven costs for the different categories?

The wide differences in calculated VIR from the different cost models is largely attributable to differences in two types of input assumptions: (1) parameters that determine expected annual energy production; and (2) parameters that determine the installed cost of the solar systems. To facilitate understanding of the wide discrepancy in modeled VIR, Staff describes the results of a series of calculations in Section IV. H of these final comments. These calculations reflect that different assumptions regarding factors such as insolation in different areas, solar panel orientation, shading, the degradation of solar panel output over the life of the project, and input assumptions for installed project cost and financing significantly impact VIR. The specific impact of these assumptions is shown Staff's Table 2 in Section IV. H.

8. System Quality: What system quality requirements should the Commission impose, if any?

The Commission should adopt quality and reliability standards in place for existing ETO and ODOE programs. Staff explains this recommendation more fully in its comments below.

9. Rate Adjustments. Should the Commission use a formulaic approach in adjusting rates (i.e. hardwired adjustment) or an approach that leaves the Commission flexibility in how it adjusts rates?

The Commission should implement a rate-adjustment mechanism that has eight semi-annual rate adjustments and a rebuttable presumption that a rate adjustment, up or down, is appropriate if certain capacity targets are met in the preceding six-month period. Such an approach will clearly define when and how rate adjustments may be made, but will leave the Commission flexibility to determine that the circumstances as whole do not warrant a rate adjustment. Staff's proposed rate adjustment mechanism is described in Section IV. J, below.

10. Capacity Reservation Activity: What information about the level of activity (e.g. available capacity) should be made public, and why?

Electric companies should disclose information regarding available capacity semi-annually, in connection with each rate adjustment window in Staff's proposed rate-adjustment mechanism. The electric companies should also disclose when capacity in any rate class is fully subscribed. These publications give interested parties sufficient information on which to base a petition to the Commission to change the capacity allocations among customer classes or years, and also, sufficient information regarding VIR to decide whether to participate in the VIR Pilot Programs.

Communication about the level of activity should otherwise be limited to graphical representations of the size range of installations, generally located on a map. This information would be available for positive publicity about the pilot programs, and provide visibility to how rapidly capacity is being deployed, in a very general sense.

Real-time information about available capacity could distort learning because such information could be used for "limited time offers" that may incent participation. Staff recommends that the Commission design the pilot programs so that retail electricity consumers will engage in programs because programs pencil out for them, not because there is a sale on, "where the deal will never be better than it is today."

III. Solar Capacity Standard.

Staff AR 538 recommendation

Staff recommends that the Commission adopt proposed Oregon Administrative Rules:

860-084-0000 Scope and Applicability of Solar Photovoltaic Programs
860-084-0010 Definitions for Solar Photovoltaic Capacity Standards and Pilot Programs,
860-084-0020 Solar Capacity Standard
860-084-0030 Qualifying Systems under the Solar Photovoltaic Standard
860-084-0040 Measurement of Capacity under Solar Capacity Standard
860-084-0050 Compliance Report
860-084-0060 Cost Recovery
860-084-0070 Renewable Energy Certificates and Compliance with Renewable Portfolio Standards
860-084-0080 Implementation Plans

Parties' positions

Portland General Electric Company ("PGE") objects to Staff's initial proposed OAR 860-084-0020, which specifies each utility's portion of the SCS. PGE recommends that the Commission base each utility's share of the capacity standard on each utility's share of total 2008 retail sales volume, as opposed to each utility's share of total 2008 retail sales revenue.

A coalition of parties led by the Renewable Northwest Project ("the RNP Coalition") opposes Staff's recommendation to use a conversion factor to convert nameplate capacity ratings reported in direct current watts to a capacity rating reported in alternating current watts. (*See* proposed OAR 860-084-0040.) The RNP Coalition asserts that the capacity of facilities used to comply with the SCS may be measured under standard test conditions and that no conversion factor is necessary.[4]

Discussion

1. **The Commission should base its allocation of the 20 MW SCS on each utility's share of retail sales volumes rather than on each utility's share of 2008 retail sales revenue.**

HB 3039(3) provides "the minimum generating capacity for each electric company is determined by multiplying 20 megawatts by a fraction equal to the electric company's share of **all retail electricity sales** made in this state in 2008 by all electric companies." (emphasis added.) When drafting the proposed rules to implement the SCS, Staff interpreted this language to mean the SCS allocation should be based on revenue from retail sales. Accordingly, the allocations in Staff's initial proposed OAR 860-084-0020, are based on this assumption.

PGE argues that sales should be interpreted as "the proportion of power consumed by retail electricity consumers" (sales volume) rather than as "the proportion of utility revenues" (sales revenue) and points to requirements of the Renewable Portfolio Standard (RPS) that are based on MWh sales rather than revenue.[5]

Staff agrees that it is appropriate to allocate capacity for the SCS in the same manner that the RPS imposes qualifying electricity standards on electric utilities and recommends that the Commission adopt proposed OAR 860-084-0020 as modified below:

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~~ **10.9 megawatts**
(2) Pacific Power: ~~7.9 megawatts~~ **8.7 megawatts**
(3) Idaho Power Company: ~~0.3 megawatts~~ **.4 megawatts**

2. **The Commission should require utilities to use a conversion factor when converting capacity ratings reported in direct current watts to capacity ratings reported in alternating current watts.**

Under HB 3039, the total capacity installed under the SCS and under the VIR Pilot Programs must be measured on the AC side of the inverter. Staff recommends the Commission use an industry-standard conversion factor to translate the manufacturer's nameplate capacity rating to capacity representing

[4] Comments of the RNP Coalition 34.
[5] PGE Opening Comments 16 and Senate Bill 838 section 6.

the actual capacity on the alternating current (AC) side of the inverter for qualifying systems used in the VIR Pilot Programs and to meet the SCS.

Although the RNP Coalition is correct that capacity can be measured as the maximum alternating current output, the measurement cannot be made until there is sufficient data from the system's operation. It is critical for the pilot programs that capacity estimates be available before the systems come on-line to allow utilities to track the amount of reserved and available capacity for the pilot programs. Although it is less critical to have early capacity estimates for purposes of the SCS, Staff believes it is appropriate to use the same method to measure capacity for the VIR Pilot Projects and SCS.

Additionally, measurements of actual capacity are influenced by environmental conditions. The RNP Coalition has recommended that measurement take the place of a conversion factor but has not explained how measurement variability would be controlled or eliminated or why this variability is unimportant. In the absence of any other proposals that will meet the time and accuracy requirements as well as the conversion factor, Staff recommends the Commission adopt Staff's proposed OAR 860-084-0160.

Staff UM 1452 recommendation

None.

IV. VIR Pilot Programs.

A. Pilot Program Requirements

Staff AR 538 recommendation

Staff recommends the Commission adopt proposed Oregon Administrative Rules:

860-084-0000 Scope and Applicability of Solar Photovoltaic Programs
860-084-0010 Definitions for Solar Capacity Standard and Pilot Programs
860-084-0100 Solar Photovoltaic Pilot Programs
860-084-0110 Qualifying Systems for the Solar Photovoltaic Pilot Programs
860-084-0120 Systems Eligible for Enrollment in Pilot Programs
860-084-0130 Ownership and Installation
860-084-0140 Assignment of Payments
860-084-0240 Standard Contracts
860-024-0250 Billing and Payment Requirements
860-084-0360 Volumetric Incentive Rates and Payment – Net Metering Option
860-084-0365 Volumetric Incentive Rate Bidding Option

Proposed OAR 860-084-0100 requires electric companies to offer a VIR bid option and a VIR net-metering bid option and specifies that the Commission will determine which retail electricity customers are eligible for each option by Commission order. Proposed OAR 860-084-0360 and OAR 860-084-0365 prescribe certain elements of both options.

Staff has modified proposed OAR 860-084-0010, Definitions for Solar Capacity Standard and Pilot Programs, to include a definition of "qualifying third party." Under OAR 860-084-0130 (regarding ownership and installation), an "eligible system" may be owned, operated or owned and operated by a "qualifying third party." In its original draft of proposed rules, Staff included a rule defining "qualifying third parties." This rule provided that electric companies could not be "qualifying third parties." Staff inadvertently omitted a rule defining "qualifying third parties" in the revised proposed rules released on November 14, 2010.

Staff has also modified definitions of "eligible energy," "excess generation," "nameplate capacity," "payable generation," "reservation start date," "resource value," "volumetric incentive rate," and the rules regarding ownership and installation and standard contracts. The changes are intended to facilitate Staff's VIR net-metering option or are in response to recommendations from other parties.

Staff's final proposed OAR 860-084-0100 omits the requirement that electric companies establish pilot programs prior to April 1, 2010.

Parties' positions

ELAW and OREP oppose Staff's recommendation for VIR net-metering and bid options.

PGE recommends that the Commission reject the proposed rule prohibiting VIR Pilot Program participants from assigning VIR payments to electric companies. PGE also recommends that the Commission allow electric companies to operate, own, or operate and own qualifying systems.[6]

RNP recommends revisions to the proposed rules' definitions of "equipment package"; "nameplate capacity"; "IEEE standards," "reservation start date"; "system requirements"; and "resource value" (OAR 860-084-0010) and the proposed rule regarding ownership and installation (OAR 860-084-0110).

Discussion

Staff will discuss the merit of the VIR net-metering options and VIR bid-options in Section V. when addressing competing proposals to implement VIR in light of jurisdictional limitations.

1. **Electric companies should not be qualifying assignees or qualifying third parties eligible to own or operate a qualifying system.**

PGE recommends that the Commission allow participants to assign VIR payments to electric companies and also allow electric companies to own, operate, or own and operate eligible systems because (1) HB 3039 does not preclude utilities from operating or owning the qualifying systems; and (2) prohibiting utilities from owning or operating the systems may inhibit larger projects, such as the Sunway project, without good cause.[7]

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[6] PGE Opening Comments 16-17.
[7] PGE Opening Comments 16-17.

Staff agrees that HB 3039 does not preclude utilities from owning the systems that generate energy under the pilot programs. Staff believes that the additional program and regulatory process complexity required by utility or affiliate ownership and operation is not warranted given the VIR Pilot Programs' limited duration and capacity.

If electric companies are allowed to own or operate qualifying systems in the VIR Pilot Programs, the Commission, or the utilities, would have to implement protocols to ensure the utilities do not have a conflict of interest (or to ensure that there is no perception that utilities have a conflict of interest) with respect to managing the capacity reservation process, approving or denying interconnection requests, or creating and sharing information about network locations that are favorable for interconnection.

On the other hand, it does not appear that allowing utilities to own or operate qualifying systems would benefit ratepayers. If utilities participate in the VIR Pilot Programs by investing capital dollars in solar PV systems and contracting with retail electricity consumers to install these systems on their behalf, Staff expects that the utility will apply for recovery of this investment in rates and report the VIR payments (that it makes to itself) as Miscellaneous Revenue. This accounting and rate recovery will distort learning from the VIR Pilot Programs: the actual VIR will not incent (or disincent) utility participation. This is because participants who have eligible systems installed or operated by electric companies will likely not be incented to participate in the pilots by VIR. Instead, they will be incented to participate by solicitations by the electric companies. And the electric companies will not be incented by the VIR because return of their investment or expense will ties to the rate-making process, not VIR payments.

Furthermore, PV system investments that are recovered through ratemaking processes will be paid back at a rate higher than those proposed under Staff proposed VIR. The costs of communicating the benefits of utility ownership and operation, on behalf of the retail electricity consumer, are likely to be difficult to separate from the costs of communicating the pilot program. In such a case, the ratepayer is at risk of paying twice for this marketing and business generation expense: once in the volumetric incentive rate and again through cost recovery of the costs of administering the pilot programs.

Finally, the capacity of the pilot programs is a valuable and limited resource for learning; Staff has identified nothing that it can learn with the utilities as "developers" that cannot be learned through the participation of non-utility developers.

2. The Commission should accept some, but not all, of the RNP Coalition's recommended modifications to the proposed rules regarding pilot program requirements.

Staff has modified its definition of "nameplate capacity," "reservation start date," "resource value," and "volumetric incentive rate," and its proposed rule regarding ownership and installation in response to recommendations by the RNP Coalition. Staff recommends that the Commission reject the RNP Coalition's proposed changes to the definitions of "IEEE Standards," "equipment package," and "system requirements." The RNP Coalition's recommendation regarding the definition of IEEE standards is unlawful because the proposed language would delegate Commission authority to another body. The recommended change to "equipment package," unnecessarily departs from existing net-metering rules. And finally, Staff does not agree that it is inappropriate to exclude any reference to "system requirements" when determining the output of a qualifying system.

3. **HB 3039 requires that the Commission, not electric companies, establish VIR Pilot Programs by April 1, 2010.**

HB 3039 requires that the Commission establish VIR Pilot Programs by April 1, 2010. The Commission is on track to do so. However, it is not clear that utilities will have time to file tariffs and implement the necessary process to implement these programs by April 1, 2010. Accordingly, Staff's final proposed OAR 860-084-0100 requires that electric companies establish pilot programs, but does not specify the companies must do so by April 1, 2010.

Staff UM 1452 recommendations

Establish guidelines for the VIR bid option.

Order electric companies to develop RFP's for VIR bid option

Order electric companies to file tariffs to implement the VIR Pilot Programs established by the Commission within 30 days of the Commission order in Docket No. UM 1452.

Order that VIR Pilot Program applicants with small- or medium-scale systems are eligible for VIR net-metering option in OAR 860-084-0100(2).

Order that VIR Pilot Program applicants with large-scale systems are eligible for the VIR bid option in OAR 860-084-0100(3).

Adopt the following guidelines regarding "permanently installed": "A system is permanently installed if it is intended to be in place for the duration of its useful life. A permanently installed system must be secured to a permanent surface. Any indication of portability, including, but not limited to, temporary structures, quick disconnects, unsecured equipment, wheels, carrying handles, dolly, trailer, or platform, will indicate the system is not permanently installed."

Parties' positions

As noted above, ELAW and OREP oppose Staff's proposal for a VIR net-metering option and VIR bid option. The RNP Coalition supports both options, with modifications to certain elements that are discussed under later subsections.

The RNP Coalition and ELAW recommend that the Commission base the definition of "permanently installed" on criteria used in other jurisdictions. [8]

Discussion

[8] Opening Comments of ELAW 4-5; Comments of the RNP Coalition 3.

Imposing VIR net-metering for participants installing small- and medium-scale facilities and VIR bid option for participants installing large-scale facilities. Staff recommends the net-metering option for participants with small- and medium-scale systems because these participants are likely to be less sophisticated than those installing systems with capacity of 100 kW and above, and thus, less likely to engage in the VIR bid process. The net-metering option is simpler, more accessible, and less expensive for participants installing systems with capacity of 100 kW and less.

Second, Staff's proposal to limit VIR net-metering to small-scale and medium-scale systems is intended to minimize the risk of perverse incentives. As stated in response to Commission question no. 3, Staff believes that participants with large-scale systems are the most likely to be incented to waste energy under a VIR net-metering option. Accordingly, Staff does not recommend that the Commission implement the VIR bid option for these customers.

Third, Staff proposes two VIR options to increase opportunity to test VIR.

VIR net-metering option. The components of the VIR net-metering option are specified in proposed administrative rules or other sections of these final comments.

VIR bid option. Staff proposes the Commission adopt the following structure for the VIR bid option:

a) Utilities develop and file for Commission approval a draft RFP for large-scale systems;
b) Bid scoring and evaluation based primarily on price without adjustment for non-price factors;
c) Bidding capped at the VIR established for medium-scale systems;
d) Bids selected from the lowest VIR to the highest, until the targeted capacity in the RFP is achieved; and
e) No single developer, financer, or retail electricity consumer has exceeded their capacity limit under the pilot program.

Permanently installed. HB 3039(2) specifies that systems generating energy for the pilot programs must be "permanently installed." Staff previously recommended that "permanently installed" means a system that could not be disconnected within 15 years of its installation. ELAW and the RNP Coalition note that this definition is inconsistent with definitions used in other jurisdictions. Staff agrees that a modification to the previously proposed definition is appropriate and recommends a guideline based on guidelines provided in ELAW's opening comments.[9]

B. Quality and Reliability.

<u>Staff AR 538 and UM 1452 recommendations</u>

Adopt proposed OAR 860-084-0120, which specifies that VIR-Pilot-Program-eligible solar photovoltaic systems must be (1) in compliance with the siting, design, interconnection, installation, and electric output standards and codes required by the laws of Oregon, (2) certified by the consumer

[9] *See* Opening Comments of ELAW 4-5.

as constructed with new components; and (3) compliant with Commission quality and reliability requirements for photovoltaic systems and system installations.

Adopt guidelines for quality and reliability from ETO, which ETO developed jointly with the Oregon Department of Energy ("ODOE"): "Solar Electric System Installation Requirements, Developed by the Energy Trust of Oregon," version 13, released 5/18/2009 and found at the following url: http://energytrust.org/library/forms/SLE_RQ_PV_SysReq.pdf

Order that solar PV systems installed under the VIR Pilot Programs must be installed by ETO Trade Allies that are in good standing as ETO Solar Trade Allies and that these systems be subject to the random audits established to audit performance of Solar Trade Allies. Staff recommends the Commission authorize the ETO to charge installation contractors up to $500 for inspection and re-inspection in the case of a failed audit.

Order that require estimates of energy generation from a system installed under the pilot program be provided by ODOE TCCT certified solar installers according to ODOE estimation calculations. All ETO Solar Trade Allies must have an ODOE TCCT certified solar installer on staff.

Parties' positions

No party has opposed the idea of imposing quality and reliability standards in the VIR Pilot Programs in written comment or during the workshops. Staff introduced its proposal to adopt guidelines from the ETO in its Opening Comments and does not know if any party opposes adopting these guidelines.

Staff's proposal regarding installation requirements is new in these final comments, and Staff does not know whether other parties oppose it.

Discussion

Adopting quality and reliability requirements would help to ensure that the VIR Pilot Programs incent the same type of facilities incented under existing incentive programs (ETO incentives and Oregon tax credits). Further, adopting such requirements, as well as guidelines regarding installations, will protect VIR Pilot Program participants.

C. Standard Contract.

Staff AR 538 recommendation

Adopt proposed OAR 860-084-0240 requiring electric companies to (1) draft a 15-year standard contract according to Commission requirements; (2) submit the standard contract template to the Commission for approval as part of their VIR tariff filings; and (3) offer the standard contract to eligible consumers that have reserved capacity in the company's VIR Pilot Program. Under proposed OAR 860-084-0240 standard contracts would include:

(a) Name and address of retail electricity consumer and address of qualifying system;

(b) Volumetric Incentive Rate based on the VIR in place at the time of the consumer's capacity reservation and specifying whether the VIR is for the bid option or net-metering option;
(c) Pilot program option allowing a participant using the net-metering option to donate excess generation to the electric company's low-income assistance program or to receive payment for this excess generation at a market-based rate. In order to choose second option, participant must certify in the contract that he or she has authority to sell energy for resale at market-based rates;
(d) Contract term;
(e) Certification by the participant that his qualifying system i) will not be subsidized by ETO incentives or State of Oregon tax credits; ii) is a new system; and iii) meets quality, reliability, and system installation requirements established by Commission guidelines;
(f) Participant's agreement to release information about participation in pilots;
(g) Participant's agreement to participate in up to three surveys regarding the effectiveness of the pilots and a statement that electric company will withhold the participant's VIR payment if the participant does not complete a survey;
(h) Preferred payment option;
(i) Assignment of payment, if applicable;
(j) Transfer of contract provision;
(k) Disclosure that VIR payments may be taxable as income under Oregon and Federal tax law and that an eligible system may be subject to property tax in Oregon;
(l) Names and addresses of solar installer or contractor and system financer and description of the PV equipment package.
(m) For VIR net-metering participants, certification that the qualifying systems complies with OAR 860-084-0100(2)(e).

Staff recommends that the Commission not require utilities to use the same standard contract. Instead, Staff recommends that the Commission require each utility to develop its own standard contract for all VIR Pilot Program transactions.

Parties' positions

The RNP Coalition recommends that the Commission clarify in subsection (1)(a) that the standard contract is not a purchase agreement. The RNP Coalition also recommends that the Commission modify subsection (3)(d)(D) to require that retail electricity customers certify that "the system and its individual components are new and have not been previously installed," as opposed to requiring customers to certify that "the system is new."[10]

Discussion

Under HB 3039, electric companies must enter into contracts with consumers who install eligible qualifying systems and successfully reserve capacity. To simplify the contracting process and ensure standard contracts are consistent with Commission requirements, Staff recommends that the Commission adopt proposed OAR 860-084-0240. Staff agrees that the changes suggested by the RNP Coalition are appropriate and has modified its proposed OAR 860-084- 0240 accordingly.

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[10] Comments of the RNP Coalition 43.

Staff UM 1452 recommendation

None.

D. Capacity Reservation.

Staff AR 538 recommendation

Adopt proposed Oregon Administrative Rules:

860-084-0210 Capacity Reservation, Timing and Duration
860-084-0230 Application for Capacity Reservation

Parties' positions

The RNP Coalition asserts that under Staff's original proposal for capacity reservation, developers, particularly those of large and medium systems, will take on significant risk that their initial investment in qualifying systems may go unrecovered. This is because an application package must include detail regarding the proposed system and because developers of medium and large system will have to spend money for legal fees, site visits, design and engineering work, etc., before knowing whether their requests for capacity will be approved (for small developers) or selected by random drawing (by medium and large developers). The RNP Coalition recommends that the Commission reject Staff's proposal to allocate capacity to medium and large projects by lottery in certain circumstances, and Staff's proposed timeline for site development. The RNP Coalition proposes a different method to reserve and allocate capacity, under which applicants provide a deposit, a signed contract, proof of site control, and use of licensed and bonded contractors and comply with a "rigorous deadline" by which the system must be installed.[11]

Ecumenical Ministries of Oregon ("EMO") notes that most of its constituents would fall into lower-end the medium-scale category and would therefore have to compete for capacity with commercial installations and asks that the Commission allow it to apply for capacity at any time, rather than during enrollment windows.[12]

Discussion

The capacity reservation process must balance an applicant's needs with those of the electric companies, and also provide opportunity for a broad range of participation. Staff has attempted to do balance these needs by requiring that applicants provide information showing that the project is viable. Staff agrees it is appropriate to modify the proposed rules regarding capacity allocation to address the RNP Coalition's concerns regarding unrecovered investment. However, Staff does not agree with the modifications proposed by the RNP Coalition. The proposed rules submitted by Staff in these final comments incorporate different fixes.

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[11] Opening Comments of RNP Coalition 11.
[12] Opening Comments of EMO-OIPL 3.

First, Staff agrees that it is possible to require less information regarding interconnection in the capacity reservation application and has modified its proposed capacity reservation application requirements accordingly.

With respect to the RNP Coalition's opposition to allocating capacity to participants with medium-sized systems when utilities receive applications for more capacity than is available, Staff sees no difference between the failure to secure a capacity reservation in the random drawing process and the failure to secure a capacity reservation in a first come, first served process that is oversubscribed. Staff believes the random drawing is critical to prevent accusations that the companies are not managing the program properly. Furthermore, in response to the RNP Coalition's concern that developers may attempt to game the random-drawing process by submitting multiple applications, Staff has proposed a rule requiring that developers may submit only one application per location and must certify the total percent of pilot program capacity secured.

Staff's proposal for a month-long application collection and a random drawing for participants with medium-sized systems has a positive, but unintended consequence. The random-drawing process increases the likelihood of a broader distribution of developers who secure a capacity reservation. A first-in-first-out process has potential to result in a significant portion of capacity reserved by a single developer.

The RNP Coalition is concerned that participants will be able to reserve capacity even though there is little likelihood they will actually install a system. To address this concern, the RNP Coalition recommends that applicants for a capacity reservation should provide documentation of a fully defined, viable project, a signed contract, and documentation that financing has been arranged. RNP does not describe who should be responsible for vetting project applications to determine whether they meet these criteria.

In response to the RNP Coalition's concern regarding reserved, but unused capacity, Staff modified its proposed rules limit applicants to two opportunities to convert successful reservations of capacity to installations. If capacity is reserved and not installed, the retail electricity consumer would have only one other opportunity to secure and install capacity.

Staff UM 1452 Recommendations

Order that VIR Program participants with small-scale systems must use the capacity reservation mechanism in OAR 860-084-0195(2)(a).

Order that VIR Program participants with medium-scale systems must use the capacity reservation mechanism in OAR 860-084-0195(2)(b).

Order that VIR Program participants with large-scale systems must use the capacity reservation mechanism in OAR 860-084-0195(2)(c).

Order that VIR Program participants that are non-profit organizations must use the capacity reservation mechanism in OAR 860-084-0195(2)(b), if their systems are 100 kW or less.

Order electric companies to file tariffs describing the capacity reservation mechanisms no later than 30 days from the date of the Commission's UM 1452 order.

E. Interconnection and Interconnection Applications.

Staff AR 538 Recommendation

Adopt proposed Oregon Administrative Rules:

860-084-0260 Interconnection Requirements for Solar Photovoltaic Pilot Program
860-084-0270 Authorization to Interconnect
860-084-0280 Interconnection Cost Responsibility
860-084-0300 Insurance
860-084-0310 Level 1 System Interconnection Review
860-084-0320 Level 2 System Interconnection Review
860-084-0330 Level 3 System Interconnection Review
860-084-0340 Installation, Operation, Maintenance, and Testing of Contracted Systems
860-084-0350 Requirements after Approval of Solar Photovoltaic Interconnection

Parties' positions

PGE, PacifiCorp, and Idaho Power are in relative agreement that the Commission should adopt the interconnection rules used in the standard net-metering program. PacifiCorp and Idaho Power state that "by incorporating established interconnection processes into the net metering VIR program, the program will reduce administrative complexity and avoid confusion for consumers who may have trouble distinguishing between the net metering VIR program and the traditional net metering program."[13] PGE states that it supports the general adoption of net metering interconnection rules with modifications to the cost recovery mechanism in proposed OAR 860-084-0280 and 860-084-0290 and minor modifications to proposed OAR 860-084-0330 and 860-084-0340.[14]

The RNP Coalition also "generally" agree with Staff's proposal to mirror the Commission's net-metering rules, but suggest minor modifications to proposed OAR 860-084-0260 regarding certification requirements and reasonable costs in proposed OAR 860-084-0290.

Discussion

Interconnection costs. Staff's initial proposed interconnection rules mirrored net-metering rules in OAR 860-039-0015 through OAR 860-039-0050, with the following modifications:

1. For level 2 and level 3 interconnection reviews the Commission will determine an application fee by order. If the interconnection request is denied, the application fee will be refunded;
2. The time in which an electric company must respond to an application is extended;
3. The pilot program applicant may choose the location of the meter;

[13] Joint Comments of PacifiCorp and Idaho Power 5.
[14] PGE Opening Comments 12-13.

4. The costs of interconnection, up to a reasonable limit, are borne by the electric company, instead of by the applicant; and,

5. The customer is responsible for interconnection costs exceeding the cost allowance limit that is established by the Commission.

In Opening Comments, Staff specified that under its VIR net-metering proposal, systems serving multiple retail loads at differing retail rates must be wired and metered as independent systems. For purposes of the interconnection costs, Staff proposed that these systems be treated as multiple projects.

Staff's initial recommendation that the utility bear the cost of interconnection, up to a reasonable limit, was based on Staff's understanding that such costs are recoverable in utility rates, whether they are integrated into VIR or borne directly by the electric company. However, Staff's proposed VIR are based on project cost data for 2008-2009 from the Energy Trust of Oregon, which includes interconnection costs. Accordingly, Staff's initial proposal for an interconnection cost allowance would essentially pay the customer twice for interconnection.

In light of this double-recovery issue, Staff no longer supports the proposed minor modifications listed as 1, 3, 4, and 5 above. Staff has modified proposed OAR 860-084-0280 Interconnection Cost Responsibility, proposed OAR 860-084-330 Level 3 System Interconnection Review, and proposed OAR 860-084-0350 Requirements after Approval of a Solar Photovoltaic Interconnection, so that they are consistent with existing net-metering rules and will not allow VIR Pilot Program participants to double recover interconnection costs.

Other Staff proposed modifications to net-metering rules. Staff agrees with PGE, PacifiCorp, and Idaho Power that adopting the interconnection rules used in the standard net-metering program will reduce administrative complexity and avoid confusion between the existing program and the VIR net-metering proposal. In fact, this is why Staff proposed only minor modifications to the current net-metering interconnection rules and now only proposes three modifications to the Commission's net-metering rules.

Staff's first proposed modification to the net-metering rules extends the time utilities have to respond to interconnection requests. Staff believes this extension is warranted because utilities may receive a flood of interconnection requests at the beginning of the pilot projects. Staff does not anticipate this extension will cause confusion.

Staff's investigation of Commission jurisdiction to execute the VIR Pilot Programs indicates that the grid may not be used to aggregate energy generated by multiple systems on a consumer's premises. Instead, any aggregation must be done "behind" the customer's meter. Therefore, Staff does not recommend that the Commission adopt the net metering language in section OAR 860-039-0065 Aggregation of Meters for Net Metering. While this modification does add complexity to the VIR net-metering proposal, Staff believes it is a necessary modification.

Staff previously proposed language that would allow additional cost allowances to customers who had systems serving multiple retail loads at differing retail rates and wished to be wired and metered as independent systems for purposes of maximizing its offset of load at the customer site. However, due to Staff's change to proposed rules regarding cost allowances; Staff no longer supports allocating additional interconnection cost allowances to this specific customer group.

Staff's final proposed modification to the existing net-metering rules is to allow the utility to charge an additional monthly service charge for the meter. Staff's proposed VIR Pilot Program net-metering option requires an additional meter at the customer's premises, for which the utility will incur costs and an on-going monthly service charge. Staff recommends that the Commission impose a $10 monthly service charge by rule and modified proposed OAR 860-084-0280 (4)(b) to do so.

RNP proposed modifications. Staff recommends that the Commission reject the RNP Coalition's proposed changes to certification requirements in proposed OAR 860-084-0260. [15] Proposed OAR 860-0840 is consistent with the Commission's net-metering rules. The RNP Coalition did not provide a reason for its recommendation to depart from the certification standards for the existing net-metering program. In absence of a compelling reason to differentiate between the interconnection requirements of pilot program systems and net-metering systems, Staff does not agree with the RNP Coalition recommendation.

Staff does not object to the RNP Coalition's recommendation to add language to proposed OAR 860-084-290 that specifies an applicant may choose to pay for interconnection costs above the reasonable cost standard without obtaining a Commission order.[16]

<u>Staff UM 1452 Recommendation</u>

None.

F. Measuring Capacity.

<u>Staff AR 538 recommendation</u>

Adopt proposed OAR 860-084-0160. OAR 860-084-0160(1) mirrors the requirement in HB 3039 that the capacity of solar photovoltaic energy systems used in the VIR Pilot Projects must be measured on the alternating current side of the system's inverter. OAR 860-084-0160(2) specifies electric companies will calculate the conversion of nameplate ratings reported in direct current watts to an alternating current rating in watts by multiplying the direct current watts by 0.85.

<u>Parties' positions</u>

The RNP Coalition's opposition to a conversion factor was set forth in Section III, above.

<u>Discussion</u>

For the reasons stated in Section III, Staff recommends that the Commission adopt proposed OAR 860-084-0160.

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[15] *See* Comments of RNP Coalition 45.
[16] *See* Comments of RNP Coalition 47.

G. **Establishing and Terminating Contracts.**

<u>Staff AR 538 recommendation</u>

No recommendation in addition to Staff's recommendation to adopt proposed OAR 860-084-0240, Standard Contracts, as modified in these final comments. (*See* Section IV. C. Standard Contracts.)

<u>Staff UM 1452 Recommendation</u>

HB 3039 section 2(4) specifies that at the conclusion of a customer's 15-year contract under a VIR Pilot Program, the retail electricity consumer "may receive payments based upon the actual electricity generated from the qualifying system at a rate equal to the resource value." Staff recommends that the Commission take no action to implement HB 3039 section 2(4). This subsection has specific language addressing what compensation will be owed to VIR Pilot Program participants after the initial 15-year contract period expires. It is possible that fifteen years from now, the state *will* have authority to require utilities to compensate solar PV generators at a specific rate. The Commission should wait to whether the regulatory environment changes before attempting to implement HB 3039 section 2(4).

H. **Volumetric Incentive Rates**

<u>Staff AR 538 recommendation</u>

None.

<u>Staff UM 1452 Recommendation</u>

Adopt the VIR shown in Table 1 below:

Table 1. Volumetric Incentive Rates by Rate Class and Project Size.

Rate Class	IOU Service Counties	IOUs	Project Size Less Than or Equal to 10 kW	Project Size Greater Than 10 kW and Less Than or Equal to 100 kW
			$/KWH	$/KWH
1	Benton, Clackamas, Clatsop, Columbia, Lane, Lincoln, Linn, Marion*, Multnomah*, Polk*, Tillamook, Washington, Yamhill*	Pacific Power & PGE*	0.750	0.550
2	Coos, Douglas, Hood River	Pacific Power & PGE*	0.650	0.550
3	Gilliam, Jackson, Josephine, Klamath, Morrow, Sherman, Umatilla, Wallowa, Wasco	Pacific Power	0.600	0.550
4	Baker*, Crook, Deschutes, Jefferson, Lake, Malheur*, Harney*	Pacific Power & Idaho Power*	0.550	0.550

Parties' positions

Several parties have argued that the calculations underlying Staff's proposed VIR should be stated more clearly and made more transparent. The ETO supports Staff's proposal to have different VIR for different counties in Oregon, but recommends an alternative classification of the counties based primarily on estimates of local production capacity.[17] PGE opposes varying VIR by geographic regions.[18] PGE has described a "Matching Incentive" approach to calculating VIR and compared the results of this approach to those of a "Cost Based" approach.[19] At workshops held in this proceeding on January 20, 2010, OREP presented a spreadsheet model it built to calculate cost-based VIR in Oregon. Finally, on January 22, 2010, the Commission invited parties in this proceeding to address the wide discrepancy in the results of the various volumetric incentive rate calculations and the differences in input assumptions underlying the calculations.[20]

Discussion

Below is a table summarizing a series of VIR calculations to facilitate the Commission's analysis of concerns and questions regarding the calculation of VIR that have been raised in these proceedings.[21] Each step in the series is intended to quantify how a specific recommendation or issue raised by a party will impact the calculation of VIR. The series of calculations can be used to understand the wide discrepancy in rates being discussed in this proceeding.[22]

Table 2. Volumetric Incentive Rates for Small Projects in Rate Class 1 (Portland and Surrounding Counties).

[17] Opening Comments of ETO 2.
[18] AR 538/UM 1452 PGE Opening Comments 18-19.
[19] AR 538/UM 1452 PGE Opening Comments 19-23.
[20] See Question #8 in the Commission's Ruling dated January 22, 2010.
[21] Attachment A is a copy of programming code used by Staff to calculate its volumetric incentive rates.
[22] Attachment B shows the summary statistics for each step in the series of volumetric incentive rate calculations.

Step	Description	VIR ($/kWh)	Change ($/kWh)
0	Staff Opening Comments	0.61	
1	ETO County Classification and LPCs	0.57	-0.04
2	ETO TSRF	0.63	0.06
3	OREP Degradation Factor	0.67	0.04
4	OREP Insurance Cost	0.69	0.02
5	OREP Meter Service Charge	0.74	0.05
6	OREP Loan Fee	0.75	0.01
7	OREP Income Taxes	0.75	0.00
8	OREP Tax Preparation Fee	0.79	0.04
9	Finance at 7.00% Interest	0.84	0.05
10	Finance at 8.00% Interest	0.88	0.04
11	Finance at 9.00% Interest	0.93	0.05
12	Finance at 10.00% Interest	0.97	0.04

Step 0—The VIR recommended in Staff's Opening Comments.[23] Staff provided a detailed description of the calculations underlying this rate in Addendum B to its opening comments.

Step 1—Implements the county reclassification recommended by the ETO in Opening Comments. The ETO recommends moving Tillamook, Lincoln, Polk, Marion, Linn, Benton, and Lane counties from Rate Class 2 to Rate Class 1. The ETO also recommends estimating annual system generation using a local production capacity estimate of 1.1 kWh per installed watt instead of the 1.08 kWh per installed watt used in Staff Opening Comments. This reclassification increased the number of projects in this category from 160 to 242. This shift resulted in a higher median system cost but a lower median installed cost per watt due to the larger sizes of the additional projects. However, the $0.04 decrease in the VIR is solely attributable to the change in the estimated annual energy production. The combination of the slight increase in project sizes and the slight change in local production capacity increased the median annual generation from 2.932 kWh to 3,152 kWh and decreased the median VIR from $0.61 to $0.57 per kWh. The lesson learned from this step in the progression is that VIR calculations are sensitive to assumptions regarding project size and estimates of annual energy production.

Step 2--Reflects the change in VIR due to another ETO recommendation. During the January 20, 2010 workshop the ETO recommended using a "total solar resource fraction" of 90 percent to further adjust the estimates of annual energy output to account for suboptimal solar panel orientation and shading. The ETO reported that it based this recommended 10 percent reduction in output on actual data collected from systems receiving ETO incentives. The decrease in annual production increases the VIR in this step from $0.57 to $0.63 per kWh.

Step 3—Shows the result of a further decrease in annual output proposed by OREP. OREP has proposed decreasing annual energy output to account for the degradation of the solar panels over the

[23] In Staff Opening Comments all VIRs were rounding to the nearest $0.05, so this value appeared as $0.60 per kWh.

lifetime of the project. The step reflects a 6 percent reduction in annual output. Again, a lesson learned from Steps 1 - 3 is that wide discrepancies in proposed VIRs can be attributable to different assumptions related to estimated annual energy production.

Steps 4-6—Demonstrate the change in the calculated VIR from adding costs of insuring the solar PV system, paying a monthly meter service charge, and a one percent load processing fee.

Step 7-8—Show the impact of adding the cost of state and federal income taxes. For the majority of the projects in the ETO database, the projected taxable income is zero. This is because the project tax deductions exceed the projected annual expenses. Step 8 adds $100 to the annual cost for tax preparation services.

Steps 9 – 12—Show how different assumptions regarding interest rates for loan financing change the calculated VIR. Each step reflects a one percent increase in the interest rate. In the January 20, 2010 workshops, OREP presented a spreadsheet model that included placeholders of 7.5 percent interest for loan financing and 2.5 percent risk premium. The lesson learned from Steps 9 - 12 is that wide discrepancies in proposed VIR can be attributable to different financial assumptions related to the cost of acquiring a loan to purchase and install the solar PV system and assumptions regarding any required risk premium.

The results of this series of VIR calculations are not an endorsement for solar PV development in Oregon. Solar PV is a very expensive resource option. Therefore, the prudent and reasonable expenditure of ratepayer dollars is an important issue to consider when setting VIR. Simply implementing a start-high end-low approach to setting the incentive rates, with an eye towards achieving the overall pilot program goal of 25 MW of installed solar capacity, would assign secondary importance to cost-effectiveness. With hindsight, reasonable people would surely ask whether the same result could have been achieved by starting with lower incentive rates.

In setting the initial VIR, the Commission is confronted with two dangers: (1) setting the rates too low and failing to incent investment in solar PV systems; and (2) setting the rates too high and failing to spend ratepayer dollars in a cost-effective manner. Navigating between the Scylla of failed incentives and the Charybdis of failed cost-effectiveness requires a cautious approach.[24] Setting the initial incentive rates too high may not doom the ship, but the damage of starting too high cannot be undone. Setting the initial rates too low, likewise, may not doom the ship, but the damage of starting too low can potentially be undone by future rate changes. Given the irreversibility of the damage from setting the initial VIR too high, Staff recommends the Commission be conservative in setting the initial VIR.

Table 1 shows Staff's recommended VIR by rate class and project size. These rates are based on the results of the Step 8 model run described above. The rate classes are based on the ETO's grouping of counties.[25] The rates also reflect the ETO's adjustment to annual system output to account for suboptimal solar panel orientation and shading. The Step 8 model runs also includes OREP's insurance costs, meter service charge, and loan processing fee, and tax preparation cost. The

[24] http://en.wikipedia.org/wiki/Scylla_and_Charybdis
[25] Attachment B shows the summary statistics for the Step 8 calculations.

financial calculation of the loan payback amounts assume and interest rate of 7.5 percent with no assumed risk premium.

Staff recommends that the Commission use the value at the 25th percentile of the VIR distributions. For projects less than or equal to 10 kW, Staff used the value at the 25th percentile of each rate class distribution. For projects greater than 10 kW but less than or equal to 100 kW, Staff used the value at the 25th percentile of the single VIR distribution that encompasses all of the rate classes. Using the values at the 25th percentiles provides some protection against setting the initial VIRs too high and failing to acquire cost-effective solar PV systems.

I. Payment and Assignment of Payments

Staff AR 538 Recommendation

Adopt proposed Oregon Administrative Rules:

860-084-0010(11) defining "qualifying assignees"
860-084-860-084-0140 Standard Contract
860-084-0250 Billing and Payment Requirements
860-084-0360 Volumetric Incentive Rates and Payments – Net Metering Option
860-084-0365 Volumetric Incentive Rate Bidding Option

Parties' positions

Some parties oppose Staff's VIR net-metering and bid options and thus, oppose proposed OAR 860-084-0360 and 860-084-0365. Staff will address the merit of the net-metering and bid options in Section V below.

As discussed above, PGE recommends that the Commission allow utilities to be "qualifying assignees" and thus, eligible to receive VIR payments through assignment.[26]

Discussion

Staff recommends that the Commission enable broad participation in the VIR Pilot Programs by allowing multiple ownership models: third-party financing, participation by non-profit organizations, and direct ownership by retail electricity customers. The proposed rules identified above facilitate these ownership models by allowing participants to assign payments to system owners and operators.

Staff has recommended that the Commission not allow electric companies to own or operate qualifying systems. For similar reasons, Staff recommends that the Commission not allow utilities to be "qualifying assignees." Furthermore, there is little or no reason for VIR Pilot Program participants to assign utilities VIR payments if the utilities cannot own or operate the systems.

[26] AR 538/UM 1452 PGE Opening Comments 16.

Staff UM 1452 Recommendation

None.

J. Deployment of Pilot Program Capacity and Pilot Design

Staff AR 538 recommendation

Adopt proposed Oregon Administrative Rules:

860-084-0170 Distributing Solar Photovoltaic Pilot Capacity by Electric Company
860-084-0180 Distributing Electric Company Capacity Limit by Pilot Year
860-084-0190 Distributing Annual Capacity by System Size
860-084-0195 Mechanisms for Reserving Capacity

Staff's proposed OAR 860-084-0190 specifies that the Commission must allocate the 25 MW of pilot program capacity by order and that the Commission may change that allocation. Staff's proposed OAR 860-084-0170 specifies that electric companies must allocate a percentage of their total capacity limit in each of the pilot years as established in Commission order and that the Commission may change this percentage. Staff's proposed OAR 860-084-0190 specifies that pilot program capacity will be distributed by system size and classifies systems into three categories: small-scale, medium-scale, and large-scale. The rule also specifies that the pilot programs should be targeted to obtain 75 percent of generation from small systems (systems with capacity of 10 kW and less). Staff's proposed OAR 860-084-0195 specifies that the Commission will decide by administrative order which capacity classes will use which capacity reservation mechanisms.

Parties' positions

No party opposes staff's proposed OAR 860-084-0170 and 860-084-0180. The RNP Coalition opposes Staff's proposed OAR 860-084-0190 and 860-084-0195.

The RNP Coalition recommends that the Commission adopt a different version of OAR 860-084-0190. This version uses the same classification criteria and categories as in Staff's latest proposed rule, but also includes a fourth category, "smaller-scale systems," which encompass both small-scale and medium-scale systems (systems with capacity of 100 kW and less). The RNP Coalition rule specifies that the pilot programs should be targeted to obtain 75 percent of generation from smaller-scale systems.[27]

RNP objects to the mechanisms to allocate capacity in proposed OAR 860-084-0195, asserting they create too much risk of unrecovered investment in the event of an unsuccessful capacity reservation application.

[27] Comments of RNP Coalition 40.

Discussion.

The important difference between the Staff and RNP Coalition proposed rules allocating capacity by system size is how the 75 percent goal of HB 3039 section 2(6) is applied. Under Staff's proposed rule, the 75 percent goal in HB 3039 is targeted at systems with capacity of 10 kW and less. Under the RNP Coalition's proposed rule, the 75 percent goal is targeted at systems with capacity of 100 kW and less. This issue should be resolved in proper context, which is by examining several of the moveable pieces of the pilot programs at once, e.g., how capacity should be allocated across differently-sized systems and across pilot years. Accordingly, Staff will discuss this issue in connection with its recommendations to the Commission in UM 1452 as to how to allocate the VIR Pilot Program capacity.

The RNP Coalition's objections to Staff's proposed mechanisms for distributing capacity to participants were discussed in Section III.

Staff UM 1452 Recommendations

Order that:

- Pilot program capacity shall be allocated to electric utilities based on their share of 2008 retail sales revenues, with 14.94 MW allocated to PGE, 9.8 MW allocated to PacifiCorp and 0.4 MW allocated to Idaho Power;
- Pilot program capacity will be distributed to different participant classes as follows: 12 MW to small-scale; 8 MW to medium-scale; and 5 MW to large-scale. Each electric company shall allocate their proportionate share of the pilot program capacity accordingly;
- Each electric company shall allocate their proportionate share of the pilot program capacity evenly across each of the four years of the pilot programs, and unused capacity for any class of participant will be rolled over into the capacity allocated for that class the following year;
- Electric companies will file tariffs that provide for semi-annual rate adjustment windows, pursuant to a rate-adjustment mechanism recommended by Staff below;
- Electric companies will disclose available capacity prior to each pilot year and will announce when capacity in any rate category is reserved. Electric companies will also disclose information regarding available capacity to facilitate rate adjustments. Electric companies will not otherwise disclose information regarding detailed information regarding available capacity.
- Electric companies will disclose information about where capacity is reserved and where systems are installed, but in a manner that masks the actual capacity deployed, reserved, or available.

Discussion

Staff and the RNP Coalition offer competing designs for the VIR Pilot Programs. The RNP Coalition recommends short pilots designed to deploy as many systems as possible in the first two years, with the majority of capacity (50%) allocated to participants with systems between 11 kW and100 kW. Staff proposes four-year pilot programs that will provide time for a broad range of interested persons to learn about and choose to participate in the pilots, with the majority of capacity (50%) allocated to systems up to and including 10 kW. The proposals include similarities, e.g., eight "rate adjustment checkpoints" over the term of the pilots and a notice requirement for rate changes. But, the proposals differ on (1) how much of the total VIR Pilot Program capacity should be allocated per year, (2) the amount of capacity allocated to each size category of qualifying systems, (3) the capacity reservation process, (4) how much information about available capacity should be disseminated, and (5) how and when VIR should be adjusted. The table below illustrate the similarities and differences between the pilot program designs recommended by Staff and the RNP Coalition.

Table 3.Differences in Pilot Designs

PILOT PROGRAM DIFFERENCES	Staff Proposal[28]			RNP Coalition[29]			
	S	M	L	S	M (VIR)	M (bid)	L (BID)
Pilot Length	4 years			2 years			
Capacity Total	12.5	7.5	5	6	13		6
Avg/year	~3	~2	1.25	3	5	1.5	3
Capacity/year (range)	1.25 to 5	1.25 to 2.5	1.25	3			3
Within year Allocation	None			Commission mediated MW allocation[30]		None	
				Quarterly	TBD		
Application Fees	No	No	No	Yes	Yes	?	
VIR review	Semi-annual[31]			Quarterly	Automatic	n/a	
Rate changes	Can go up or down			Can only go down		One RFP process each for medium and for large	
Adjustment allowed	Yes	Yes	Yes	@100% of Quarterly MW*	@95% of MW's		
Required adjustment				None	Yes[32]: 10%		
Maximum adjustment				10%	10%		

[28] Four year proposal with majority to smaller systems, supported by Staff, OREP and ICNU.
[29] Two year proposal, with all details, supported by a broad coalition identified in RNP comments.
[30] Page 26, RNP Comments. Recommends that Commission establish MW capacity targets but doesn't define them.
[31] Review of VIR and/or of bidding process are both completed. Rates or process may or may not change.
[32] If capacity reserved reaches 95% of quarterly allocated capacity, MUST reduce rate by 10%. However, requires 10 days notice before change is effective.

Pilot Program Length. As noted above, the RNP Coalition recommends that the Commission design the pilots to deploy the 25 MW of VIR Pilot Program capacity in two years. Staff recommends the Commission deploy the capacity over four years.

The RNP Coalition argues that learning in the > 10 kW to 100 kW size range will be statistically sufficient only if ~65 100 kW systems or ~260 25 kW systems are installed in the first year of the pilot program. This reduces the annual capacity available for smaller systems (those < 10 kW) to a level lower than is reasonable, unless the pilot program is compressed to two years.[33]

In support of its proposal, the RNP Coalition argues that the solar industry has the capability to rapidly install the full amount of capacity allocated to the medium size category in a two-year period and that HB 3039 calls for the VIR Pilot Programs to enable the growth and development of the solar industry in Oregon. The RNP Coalition asserts that rapidly deploying the pilot program capacity is consistent with this legislative intent.

Staff acknowledges that the solar industry may be well positioned to capitalize on the capacity installation opportunity for medium-scale systems, in a very short timeframe. Staff also acknowledges that solar companies planning to serve as owner/operators (leasing roof space from residential and small commercial consumers) may be able to rapidly deploy capacity in population centers. Staff does not believe the same is true for customers who may install small-scale systems.

Because it is not clear that participants installing small-scale projects are ready to immediately capitalize on the VIR Pilot Programs, Staff recommends longer pilots (at least four years) to investigate whether VIR can (or cannot) attract participation across diverse geographic locations,[34] with diverse ownership models (rooftop leasing, direct ownership, and bank financing), by diverse developers (large commercial and small installers), and with diverse PV technologies (small, efficient roof mounted systems to larger pole mounted arrays). If the pilot program capacity is rapidly deployed to entities already positioned to fill this capacity in a concentrated location, using one or two business models, much less may be learned.[35]

Total Pilot Program Capacity Allocation – by system size. Both Staff and the RNP Coalition recommend classifying the qualifying systems into three categories:

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[33] For clarity, the formulas would be: Pilot Program length = t = Capacity reserved for smaller systems divided by reasonable annual capacity for smaller systems.

Reasonable annual capacity for smaller systems based on historic number of customers engaging in ETO programs today.

Capacity reserved for smaller systems = Total pilot capacity – capacity reserved for medium & larger systems)

[34] The Energy Trust of Oregon shares this judgment.

[35] The SMUD feed in tariff and Energy Trust experience with current net metering programs confirms this judgment. SMUD's 100 MW feed in tariff pilot (which was open to a wide range of renewable technologies) has been fully subscribed with a disappointing[35] lack of variety in technology (almost all solar). Both the SMUD and Gainesville feed in tariffs have resulted in a disappointing lack of variety in developers (most of the capacity was reserved by a smaller number of developers).

- smaller-scale: 10 kW and less
- medium-scale: above 10 kW and 100 kW and less
- large-scale: above 10 kW and no more than 500 kW

The RNP Coalition and Staff recommendations for capacity allocation are matched to their design proposals: the RNP Coalition recommends allocating capacity annually for two years: 6.5 MW per year to medium-size systems, 3 MW per year to small systems, and 3 MW per year to large systems. Staff recommends allocating capacity annually for four years: approximately 3 MW per year to small systems, approximately 2 MW per year to medium systems, and 1.25 MW per year to large systems. Under the RNP Coalition proposal, the majority of the VIR Pilot Program capacity (13 MW) is allocated to medium-size systems. Under Staff's proposal, the majority of the capacity (approximately 12.5 MW) is allocated to the small systems.

Both the RNP Coalition and Staff proposals offer an average of 3 MW of capacity per year to systems smaller than 10 kW. However, capacity is allocated every year for four years under Staff proposal and for only two years under the RNP Coalition proposal. Accordingly, the RNP Coalition proposal allocates only half (25% of 25 MW) of what is allocated to residential customers (small systems) under Staff's proposal (50% of 25 MW). As noted above, a two-year pilot takes away the opportunity to learn, in the residential and smaller commercial sector that are outside of the already-engaged developer community.

The RNP Coalition's argument that Staff's proposal is inconsistent with the legislature's goal to have 75 percent of the energy generated by systems up to 100 kW is not persuasive for at least three reasons. First, HB 3039 is clear that the Commission has discretion to trade off this 75 percent goal against other priorities laid out in HB 3039, namely, "demonstrating the use and effectiveness of the volumetric incentive rate," installation of the 25 MW of photovoltaic energy system capacity, and limiting rate impact. For the reasons discussed above, the Commission's investigation into the use and effectiveness of VIR will be significantly limited if the Commission allocates capacity as recommended by the RNP Coalition. Notably, OREP has supported a smaller allocation of capacity to small systems (at the 60 percent level) to enable learning about the medium size range, even though OREP believes the legislature intended that the 75 percent target is for residential customers. Second, both the RNP Coalition proposal and the Staff proposal already allocate more than 75 percent of program capacity to systems up to 100 kW.

Second, Staff does not agree that the legislature's goal is for 75 percent of the energy to be generated by systems up to 100 kW. Instead, Staff has been advised by DOJ counsel that the legislative history of HB 3039 reflects that 75 percent goal is for energy generated by residential facilities. However, because the Commission has discretion to allocate capacity in the manner that will facilitate the objective of the legislation, Staff does not believe that a debate over the legislative intent underlying the 75 percent goal is necessary.

Third, both the Staff and RNP Coalition proposals allocate more than 75 percent of capacity to systems with capacity of 100 kW or less.

The allocation of 2.5 MW per year to the medium-sized category, with the potential for installation of between 25 and 100 or more systems per year, is sufficient for investigating the effectiveness of VIR for this category. Other parties (OREP and ICNU) support Staff's position, arguing that **at least** 50% of pilot capacity should be deployed to residential consumers, based on the 50% share of retail electricity revenue paid by residential consumers. OREP argues that this number should be higher than 50% to account for the additional share of revenue collected from smaller commercial consumers.

Rate Adjustment Mechanism. Staff recommends that the Commission establish a rate-adjustment mechanism for participants with small- and medium-scale systems under which rate adjustments, up or down, are correlated to capacity availability. The elements of the mechanism are as follows:

- Rate adjustment window every six months;
- Rebuttable presumption that specified rate adjustment is appropriate if criteria are met;
- Ten percent rate reduction for rate class if available capacity fully subscribed within three months of pilot start date or the end of last rate adjustment window,
- Five percent rate reduction for rate class if available capacity fully subscribed within five months of pilot start date or end of last rate adjustment window;
- Ten percent rate increase if no more than 50 percent of available capacity is subscribed within three months of pilot start date or end of last rate adjustment window;
- Five percent rate increase if more than 50 percent, but less than 75 percent of available capacity is subscribed within five months of pilot start date or end date of last rate adjustment window;

Communication regarding pilot program activity for participants with small- and medium-scale systems is limited to the announcement of available capacity at the start of a pilot program year, announcements of available capacity at the close of each rate adjustment window, and notice at the third and fifth month of every six-month rate adjustment period of whether the criteria for a rate adjustment have been satisfied. Otherwise, communication regarding deployment and available capacity is limited to a graphic display of the locations where capacity is reserved or where systems are installed and their sizes.

The RNP Coalition proposal calls for quarterly allocations of capacity, over the two-year pilot program, with the possibility of quarterly rate adjustments for systems up to 10 kW and for systems between 11 kW and 100 kW. Rate adjustments for smaller systems would depend on whether 100 percent of capacity is utilized against a quarterly allocation. Weekly (or more frequent) communications of remaining capacity would provide a tool for developers to close deals with customers, (e.g., developers solicit participants by advertising the fact that all capacity for the quarter may be taken and rates may decline the following quarter).

Under the RNP Coalition proposal, rate adjustments would be mandatory, for medium systems, if 95 percent of capacity is reserved against a Commission defined allocation, over a Commission defined timeframe. The RNP Coalition proposal does not define the within year allocation that might serve this system size category.

This proposal requires weekly (or more frequent) communications of remaining capacity to allow developers to submit additional applications in the medium-scale category, if the automatic rate adjustment mechanism looks likely to be "tripped" by reaching reservations of 95 percent of the capacity allocated for the period. The developers would have 10 days to qualify at the higher rate, after notice that the 95 percent capacity reservation had been reached. Knowing that this trigger point was being approached (weekly or more than weekly updates) would give the developers a longer lead time to close these sales or to coordinate to not submit more reservations....so that the trigger point is not reached.

Staff acknowledges that the sales tools in the RNP's rate adjustment mechanism may be critical if the primary objective of the pilot programs was to install the 25 MW of capacity as rapidly as possible. However, this is not the primary objective of the pilot programs. The primary objective is to determine the use and effectiveness of VIR. Staff's proposal prioritizes learning over rapid capacity installation in order to facilitate understanding of what VIR motivates sustainable patterns of PV system installation. Staff is concerned that designing the pilot programs so that developers may use available capacity to incent participation will distort the Commission's ability to understand consumer reaction to VIR changes, or impending changes.

Notice of Rate Changes. Both the Staff and RNP Coalition Proposals contemplate notice before a rate change. The RNP Coalition contemplates 30-day notice for small-scale customers and 10-day notice for medium-scale customers. Staff recommends 30-day notice before a rate change.

Section for information re: bidding.

K. Rate Impact and Cost Recovery

Staff AR 538 Recommendation

Adopt proposed Oregon Administrative Rules

860-084-0370 Resource Value
860-084-0380 Cost Recovery and Rate Impacts
860-084-0390 Cost Recovery Mechanism

Discussion

Resource value. Staff's initial proposed OAR 860-084-0370 requires each electric company to file estimates on July 1, 2010, 2012, and 2014 of the 15-year levelized "resource value" of qualifying system in the respective company's pilot programs. In addition, the proposed rule requires utilities to file annual estimates beginning July 1, 2025, of the annual resource value for the company for each of the next five years, in order to implement HB 3039 section 2(4), which allows VIR Pilot Program participants to receive payments for generation based on the company's resource value.

As discussed above, Staff recommends that the Commission not attempt to specify how utilities will compensate VIR Pilot Program participants for energy generated after the initial 15-year contract period. Accordingly, Staff has modified proposed OAR 860-084-0370(2) to remove the reference to "determining payments to retail electricity customers at the end of the 15-year contract term."

Staff recommends that the Commission still require utilities to file annual estimates of resource value starting July 2025, in the event utilities ultimately will be required to compensate solar PV generators based on the utilities' resource value.

The 2010, 2012, and 2014 filings are pertinent to the Commission's determination as to whether to impose a rate cap, and Staff proposes no modification to these filing requirements.

Staff UM 1452 Recommendation

Order that electric companies may shall recover VIR Pilot Program costs under ORS 757.259.

Do not impose a rate cap.

Order electric companies to file the applications and tariffs needed to implement Staff's proposed cost recovery framework within 30 days of the Commission's order in Docket UM 1452.

Discussion

Cost recovery mechanism. Costs prudently incurred by electric companies to comply with the VIR Pilot Programs are recoverable in rates. Staff supports the overall cost recovery framework proposed by PGE in its Opening Comments.[36] First, Staff recommends that the Commission allow the electric companies to use deferred accounting to track and accumulate VIR Pilot Program costs. Costs eligible for deferral should include: VIR payments made to participating retail consumers; start-up and on-going costs associated with VIR Pilot Program administration and operation; as well as costs associated with data collection and regulatory reporting requirements.

Second, Staff agrees with PGE that costs of the VIR Pilot Programs should not be reflected in the utilities annual power cost update mechanisms. The utilities should not adjust forecasted generation or load to account for participation in the VIR pilot programs. However, in order to prevent ratepayers from paying to serve the same load twice, once through base rates and a second time through the amortization of the deferred VIR payments, Staff recommends an adjustment to the utilities' deferral balances prior to amortization.

Third, although Staff agrees with PGE that direct access customers should be eligible for participation in the VIR Pilot Programs, Staff does not, at this time, support a recommendation to include direct access customers in the allocation of program costs for ratemaking purposes.[37] Likewise, at this time, Staff does not support ICNU's recommendation that the allocations of costs to customer classes match each customer class's participation in, and benefit from, the VIR Pilot Program.[38] The ratemaking decision to base cost allocation on eligibility or participation can wait. Staff recommends that the Commission address this issue at the time of amortization of the VIR Pilot Program deferral balances.

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[36] *See* AR 538/UM 1452 PGE Opening Comments 8-11.
[37] *See* AR 538/UM 1452 PGE Opening Comments 11.
[38] *See* Opening Comments of ICNU 2.

Rate impact. Proposed OAR 860-084-0380(3) specifies that 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." Staff recommends that the Commission not impose a rate cap at this time. Staff recommends that the Commission first collect data from the pilots before determining whether a rate cap is warranted.

L. Learning and Recommendations

Staff AR 538 Recommendation

Adopt proposed Oregon Administrative Rules:

860-084-0210 Capacity Reservation, Timing and Duration
860-084-0400 Data Collection
860-040-0410 Compliance with Program Requirements
860-084-0430 Data Availability
860-084-0440 Pilot Program Overhead
860-084-0450 Reports to the Legislature

Staff UM 1452 Recommendation

Order utilities to submit draft surveys to the Commission within six months of the Commission's UM 1452 order.

Discussion

As discussed in response to Staff's response to Commission question no 5, VIR Pilot Program participants should be *required* to complete up to three surveys over the course of the pilots in order to receive VIR payments. (*See* Proposed OAR 860-084-0240(g)). These surveys can be designed to help the Commission determine which customers and customer segments are motivated by VIR, as opposed to existing incentives for the installation of SPV facilities. Staff's final proposed rule regarding survey design calls for the utilities to design the survey, or commission the Energy Trust of Oregon ("ETO") to design the surveys, and require that the utilities or ETO, if applicable, consult with the Commission and stakeholders before finalizing and distributing the surveys.

M. Pilot Year and Program Termination

Staff AR 538 Recommendation

Adopt proposed Oregon Administrative Rules:

860-084-0100 Definitions for Solar Photovoltaic Capacity Standard and Pilot Programs
860-084-0150 Solar Photovoltaic Pilot Capacity Limit
860-084-0170 Distributing Solar Photovoltaic Pilot Capacity by Electricity Company
860-084-0220 Capacity Availability

Staff UM 1452 Recommendation

V. Proposed mechanisms to implement VIR.

In implementing HB 3039, the Commission must develop a VIR mechanism that achieves the goals of HB 3039 while avoiding conflict with the Federal Energy Regulatory Commission's ("FERC's") exclusive jurisdiction to establish rates for wholesale sales of electricity in interstate commerce. Staff and other parties have proposed mechanisms to do this. The following is a list of the proposed mechanisms followed by staff's analysis of each one. Staff recommends that the Commission adopt option 1 for participants that install systems with a nameplate capacity of 100 kW's and less and adopt option 2 for all other participants.

1. Establish VIR for retail transactions (net-metering transactions) between utilities and pilot project participants.

2. Establish VIR through competitive bidding.

3. Require utilities to pay VIR for non-energy attributes of energy purchased from pilot program participants under PURPA contracts using one of the following mechanisms:

    a. Require electric companies to pay for Renewable Energy Credits ("RECs") associated with energy generated under pilots at VIR established by Commission;

    b. Require utilities to compensate QF's for non-energy attributes of energy generated under pilots at VIR established by Commission;

    c. Use avoided costs as VIR by establishing avoided costs for each electric company that reflect the unique characteristics of energy generated in the pilot programs; or

    d. Authorize the Energy Trust of Oregon ("ETO") to subsidize avoided cost rates at VIR established by Commission.

Option 1: Establish VIR for retail transactions (net-metering transactions) between electric companies and pilot project participants.

a. Parties' positions.

Staff proposes the VIR net-metering option for participants installing facilities with capacity of 100 kW and less. RNP supports the net-metering proposal. CUB states that "it can support the concept of parallel net-metering * * * as [a] workable mechanism[] to test the FIT-type approach but avoid federal jurisdiction issues."[39] ICNU believes that net-metering "best accords with the plain text of HB 3039 and is, therefore, the alternative that best implements the legislative intent of HB 3039."[40]

OREP asserts that pricing RECs is a more appropriate method to test VIR than net-metering to test because the REC method more closely resembles a traditional feed-in-tariff ("FIT"). ELAW similarly believes that requiring utilities to purchase RECs, or the environmental attributes of energy from participants at VIR, more closely resembles a FIT and is therefore preferable to the net-metering mechanism. OREP and ELAW are also concerned that the net-metering proposal will incent participants to consume more energy (so that they may sell more energy at VIR) and also, will limit the size of facilities that participants will install.

b. The Commission has jurisdiction to implement the VIR net-metering option.

The states, rather than FERC, have jurisdiction over retail sales of energy.[41] In its 1995 order in *MidAmerican Energy Company*, FERC clarified that net-metering transactions are retail transactions to the extent the transactions do not result in a net sale to the electric company.[42] FERC also concluded that it is not necessary for netting to occur in real time in order for the net-metering transactions to retain their status as retail sales. Instead, FERC has specified that the netting may occur over a reasonable period of time.[43]

PGE questions staff's conclusion that the Commission has jurisdiction to implement the VIR net-metering proposal. PGE asserts that because the rate paid to a participant for the eligible energy transmitted by the participant to the utility may far exceed the participant's bill from the utility for its load, the transmission of energy to the electric company may be considered a wholesale sale.[44]

PGE appears to misunderstand the proposal. Customers will not receive VIR for energy transmitted to the utility, but for energy the customers generate and "use."[45] In essence, a customer will receive a state-mandated subsidy for every kW the customer generates that offsets his load. Because it is not necessary for the customer to net his usage against his production in real time, the customer may (and inevitably will) transmit some of the energy he produces to the utility. However, to the extent these transmissions do not exceed the customer's load over the course of a netting period; a net-metering customer will have been deemed to have used all the energy he generated.

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[39] Opening Comments of CUB 4.
[40] Opening Comments of ICNU 4.
[41] *Federal Power Commission v. Southern Cal. Edison Co.*, 376 U.S. 205, 214 (1964) (citing *Illinois Natural Gas Co. v. Central Illinois Public Service Co.*, 314 U.S. 498 (1941)).

[42] FERC 61,340 2001 WL 306484 (*MidAmerican Energy Co.*). *See also* 129 FERC 61,146 (Nov. 19, 2009)(*SunEdison LLC.*).

[43] *Id.*
[44] AR 538/UM 1452 PGE Opening Comments 4.
[45] As explained below, the customer need not actually use all the energy himself. As long as the customer consumes at least as much as he generates over the course of a netting period, the customer is deemed to have used the energy he generated for the purpose of net metering.

PGE does not explain why the disparity between VIR for energy produced and used by a VIR Pilot Program participant and retail rates for energy transmitted to the participant would convert the transaction from one that is under the state's jurisdiction to one that is under FERC's jurisdiction. The material question is whether the participant is using more energy than he is producing. To the extent the participant consumes more energy than he produces, the participant will have, for purposes of net metering, used all the energy that he produced, and any accounting for the energy used by the participant will be a retail transaction.

Because the pilot program transactions will be retail transactions, FERC has no authority to assert jurisdiction over rates the state imposes for such transactions, and specifically, no authority to assert jurisdiction over a subsidy that states may provide to generators that consume their own energy.

c. The VIR net-metering option will test the use and effectiveness of VIR.

Staff disagrees that the net-metering proposal is so inconsistent with the traditional FIT model as to be unacceptable. There are important similarities between the net-metering mechanism and a traditional FIT. Under the net-metering proposal, participants will receive a Commission-established incentive rate for energy the participant produces. The participant will know the VIR at the time he enters into a contract with the electric company and will be entitled to receive this rate for all eligible energy produced for a lengthy period of time (15 years).

Staff acknowledges that the net-metering mechanism does depart from the traditional FIT model by providing an incentive rate to participants for the energy they generate and use themselves, as opposed to energy they generate and transmit to the grid. However, it is unclear whether this difference will negatively impact the pilot programs. Many parties have commented in workshops that if the SPV systems are sized appropriately, it is unlikely that participants will produce more energy than they consume over the course of the year. If participants do not produce more energy than they consume, they will be eligible to receive VIR for all the energy that they produce, just as they would with a traditional FIT.

Staff acknowledges OREP and ELAW oppose a mechanism that may require customers to limit the size their SPV installations in order to take full advantage of VIR. However, states do not have authority to implement a traditional FIT for renewable generation. The *de facto* size limitation on SPV facilities that residential and small commercial participants can install in order to take full advantage of VIR is an acceptable trade-off for implementation of a workable and sustainable program.

Similarly, the risk that customers will consume more energy to increase the size of VIR subsidy may also be a necessary trade-off for a sustainable pilot program. In any event, Staff believes that rejecting the net-metering option because of this concern would be premature. Some participants in the workshops have asserted that it is unlikely a participant will be able to produce more energy from a SPV system installed on a residential roof than the participant uses in a year. In any event, Staff has proposed a rule that would require net-metering participants to limit the size of their installed facilities. Furthermore, Staff does not recommend that the Commission use the net-metering option for larger installations (101 kw to 500 kw) that may produce more energy than the participant uses. Instead, Staff recommends that the Commission use the VIR bid option for these participants.

d. Under the VIR net-metering option, participants may sell excess energy at market-based rates.

Under Staff's net-metering proposal, a participant that generates energy in excess of his load may donate that excess energy or sell it to the utility at market-based rates. In order to sell the energy, the participant will have to obtain authority from FERC to sell energy at market-based rates.

1. The Commission cannot require utilities to purchase excess energy at avoided cost.

Some parties have asked the Commission to investigate whether it is permissible for participants to sell excess energy to the electric company at the electric company's avoided cost rate, rather than at a market-based rate. Ordering utilities to purchase excess energy generated under the VIR Pilot Programs at avoided cost would run afoul of either the Public Utility Regulatory Act ("PURPA") or the Federal Power Act ("FPA").

Under PURPA, QFs are entitled to sell their **net** output to utilities at avoided cost.[46] Accordingly, when a state determines how to implement PURPA, it may not require utilities to compensate a QF for its **gross** output at avoided cost rates, net the value of power the QF purchases from the utility at retail rates. This is because these transactions would allow the QF to receive avoided cost rates for more power than the facility, standing alone, is capable of delivering. And accordingly, these transactions would allow the QF to receive avoided cost rates for more energy than the purchasing utility has avoided purchasing.[47] FERC has concluded that such a result is inconsistent with the requirement of PURPA and FERC's implementing regulations that utilities and their ratepayers be in the same financial position as if they had not purchased QF power.[48]

Because rates for PURPA sales are capped at the utilities' avoided costs, it is not permissible to impose VIR for the energy produced and consumed by a VIR Pilot Project participant and then allow the participant to sell excess energy at avoided cost. This is because the end result of all the transactions, the net-metering transactions and the PURPA sales, would likely be a rate for the PURPA sale that exceeds avoided cost.[49]

Finally, the Commission does not have authority outside PURPA to order utilities to purchase energy at avoided costs because the Commission does not have authority to set the rate for wholesale sales of energy in interstate commerce.

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[46] *Power Developers, Inc.* 32 FERC 61,101 (1985) *reh'g denied,* 34 FERC 61,136 (1986).
[47] *Id. See also Connecticut Valley Electric Company Inc. v. Wheelabrator Environmental Systems, Inc.*, 82 FERC 61116 (1998 WL 64136).
[48] *Id.*
[49] The Commission does have authority to allow participants in the Commission's net-metering program to sell excess energy at avoided cost because such a sale is consistent with PURPA. Meaning, when the net-metering transactions and PURPA sales are netted, the utility is in fact not required to pay more than avoided cost for the excess energy.

2. The Commission need not prescribe how participants obtain authority to sell energy at market-based rates.

Staff believes that participants must petition FERC for market-based rate authority ("MBRA") in order to sell excess energy at market rates. The RNP Coalition believes that it would be permissible for the participants to make such sales if they self-certify as QFs. This is because QFs with a capacity of no more than 20 MW are exempt from traditional rate regulation under the FPA and as such, can sell energy at market-based rates without obtaining MBRA and without filing tariffs.

Although QFs can voluntarily enter into contracts to sell energy at market-based rates without obtaining MBRA or filing tariffs, the state does not have authority to order utilities to enter into such contracts with QFs. This is because the state does not have authority to order utilities to purchase energy from QFs at a rate that differs from avoided cost. Accordingly, if the VIR Pilot Program participants are QFs, the state does not have authority to order utilities to purchase energy from them at market rates.

In any event, Staff does not believe that it is necessary for the Commission to mandate that participants obtain MBRA in order to sell excess energy. To the extent that participants want to sell excess energy at market rates, they will have to be authorized to do so. The Commission need not prescribe how participants obtain that authority.

Option 2: Participants obtain authority from FERC to sell energy at wholesale at market-based rates and sell entire output of facilities at VIR, which is established through competitive bidding.

a. Positions of the parties.

Staff proposes the VIR Bid option for participants that install facilities with capacity above 100 kW and no more than 500 kW. Under this mechanism, the transactions between the participants and electric companies would be within FERC's jurisdiction. Participants would have to obtain market-based rate authority and their contracts with electric companies would be subject to the approval of FERC.

The RNP Coalition supports this proposal.

b. The Commission has jurisdiction to implement the VIR bid option.

The State has authority to direct the resource decisions of utilities, and thus, can order utilities to procure capacity from VIR Pilot Program participants.[50] Because the Commission does not set a rate for the sale of energy to the electric companies, the Commission will not run afoul of the FPA.

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[50] *See e.g., Southern California Edison,* 71 FERC 61269 (1995 WL 327268) ("States have broad powers under state law to direct the planning and resource decisions of utilities.")

B. The remaining options are either outside the Commission's jurisdiction or would be less effective than Staff's proposals.

The remaining four proposals rely, at least in part, on the Commission's authority under PURPA. Accordingly, staff will preface its analysis of the remaining proposals with a brief discussion of this authority.

Jurisdiction over rates for all wholesale sales, including those by QFs, is vested in FERC.[51] Under PURPA, FERC is required to adopt rules that ensure rates for any sale of energy by a QF to an electric utility required under PURPA shall be at just and reasonable rates and shall not discriminate against QFs. And, 16 U.S.C. 823a-3(b) provides that FERC may adopt no rule requiring electric utilities to sell and purchase energy from QFs at "a rate which exceeds the incremental cost to the electric utility of alternative electric energy." To the extent states have authority under PURPA, it is only for "implement[ing]" the Commission's rules.

FERC has concluded that it is precluded under 16 U.S.C. 823a-3(b) from adopting rules under which states could require utilities to pay QF's more than avoided cost for purchases of energy.[52] This conclusion is supported by the United States Supreme Court, which has concluded that PURPA "sets full avoided cost as the maximum rate that the Commission may prescribe," for sales of electricity by a QF. *American Paper Institute, Inc. v. American Electric Power Service Corporation*, 461 U.S. 402, 413 (1983). FERC has also concluded that it could ascertain no legal basis under which states have independent authority to prescribe rates for sales by QFs at a rate that exceed the avoided cost cap in PURPA."[53] 70 FERC at 61,029.

With this background in mind, staff will turn to the remaining five proposals.

Option 3a: Participants become QFs under PURPA and sell net output of energy generated by SPV facilities to electric companies at avoided cost. Commission requires utilities to purchase Renewable Energy Credits ("RECs") associated with that energy at VIR established by Commission

a. Positions of the parties.

OREP and ELAW support this proposed mechanism because it resembles a traditional FIT. CUB is interested in investigating the mechanism, but is concerned about unintended consequences. Staff and the RNP coalition oppose the proposal because establishing a value for RECs that greatly exceed their market value could negatively affect how RECs are used in Oregon and other jurisdictions.

[51] 16 U.S.C. 824a-3 *et seq.*
[52] *Connecticut Light and Power Company*, 70 FERC 61,012 (1995).
[53] *Connecticut Light and Power Company*, 70 FERC 61,012 (1995).

b. It is likely within the Commission's jurisdiction to impose VIR for RECs associated with the energy produced by pilot program participants.

In 2003, FERC issued a declaratory ruling in which FERC concluded that RECs exist outside the confines of PURPA and that avoided cost rates are not intended to compensate a QF for more than capacity and energy.[54] FERC noted that the creators of RECs, the states, have authority to determine who owns the RECs and how they may be sold or traded.[55] Because the purchase and sale of RECs are independent of PURPA, it is logical to conclude that any compensation paid by utilities to generators for the RECs would not run afoul of the avoided cost cap discussed above.

c. It is possible the Commission has statutory authority to require utilities to pay pilot project participants more than the market rate for RECs associated with energy produced by the participants.

Whether the Commission may use RECs as a vehicle for VIR turns on whether the Commission has been authorized to do so by the legislature. The legislature has not granted the Commission specific authority to impose VIR for RECs. However, the legislature did grant the Commission broad authority to "establish incentive rates for the pilot programs to enable the development of the most efficient solar photovoltaic energy systems."[56]

Arguably, this authority is cabined by HB 3039 subsection 2(1), which provides that the Commission "shall 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[.]" [57] However, the Commission should not ignore the language qualifying "electricity," which is "delivered from solar photovoltaic energy systems." It may be reasonable for the Commission to conclude the Commission could test the effectiveness of VIR for the electricity described in section 2(1) of HB 3039 by pricing the environmental attributes of the electricity delivered from solar photovoltaic energy systems, which are represented by associated RECs.

d. Using RECs to impose VIR for energy produced under the VIR Pilot Programs could have negative unintended consequences.

Though it may be within the Commission's authority to impose VIR on RECs created by pilot participants, staff and other parties recommend that the Commission not do so. In order to make RECs an effective vehicle for VIR, the RECs would have to be valued at approximately 400 times their market rate.

Option 3b: Participants become QFs under PURPA and sell net output of energy generated by SPV facilities to electric companies at avoided cost. Commission requires utilities to compensate QF's for non-energy attributes of energy at VIR established by Commission.

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[54] *American Ref-Fuel Company*, 105 FERC 61,004 (2003 WL 22255784).
[55] *Id.*
[56] HB 3039 Section 2(3).
[57] HB 3039 Section 2(1)(emphasis added).

a. Positions of the parties.

ELAW, PacifiCorp, and Idaho Power support this option. PacifiCorp and Idaho Power suggest that because it is not clear that the Commission has authority to establish the rate, the Commission could order parties to enter into contracts to establish VIR rather than establishing VIR by order. [58]

Although this option is similar to the REC option discussed above, it appears that it is preempted by PURPA. RECs are creatures of the states, independent of PURPA, and have a value that is separable from the associated energy. While the environmental attributes of energy generated by QFs have a societal value, the attributes are not creatures of state statute, and do not have a value to the utilities that is separable from the energy purchased. Accordingly, it is unlikely that the state has authority to require utilities to separately purchase environmental attributes from QFs when purchasing energy and capacity under PURPA because doing so would violate PURPA's avoided cost rate cap.

FERC has clarified that avoided cost rates do not compensate QFs for the environmental benefits of energy they produce. However, FERC has also clarified that including the cost of such benefits in avoided cost rates would be inconsistent with PURPA, unless the costs were real costs that would actually be incurred by the utility when procuring energy:

> [E]nvironmental costs, if they are real costs that would be incurred by utilities may be accounted for in a determination of avoided cost rates. Under section 210(b) of PURPA, "no rule . . . shall provide for a rate which exceeds the incremental cost to the electric utility of alternative electric energy." (emphasis added). Thus, in setting avoided cost rates, a state may only account for costs which actually would be incurred by utilities. A state may, through state action, influence what costs are incurred by the utility. Thus, accounting for environmental costs may be part of a state's approach to encouraging renewable generation produced by a particular fuel, and thus increase the costs which would be incurred by utilities in building and operating plants that use fuel, and thus increase the costs which would be incurred by utilities in building and operating plants that use that fuel. Conversely, a state may also subsidize certain types of generation, for instance wind, or other renewables, through, e.g, tax credits.
>
> A state, however, may not set avoided cost rates or otherwise adjust bids of potential suppliers by imposing environmental adders or subtractors that are not based on the real costs that would be incurred by utilities. Such practices would result in rates which exceed the incremental cost to the electric utility and are prohibited by PURPA. [59]

FERC's statements above are inconsistent with the proposition that a state can simply impose a surcharge for environmental attributes on utilities purchasing QF energy under PURPA.

The alternative proposal by PacifiCorp and Idaho Power does not address the avoided-cost-cap issue. The pertinent issue is whether the Commission has authority to require utilities to compensate QF's for energy purchased under a PURPA contract at rates that exceed avoided cost. It cannot. Because

[58] Joint Comments of PacifiCorp and Idaho Power 9.
[59] *Southern California Edison Co* 71 FERC 61,269 (1995 WL 327268).

PURPA rates are set at avoided costs, the Commission does not have authority to order utilities to enter into contracts with QFs to provide QFs compensation in addition to compensation the utility provides based on avoided cost rates, notwithstanding whether that compensation is based on rate established by the Commission or through mutual agreement of the utility and QF.

Option 3c: Participants become QFs under PURPA and sell net output of energy generated by SPV facilities to electric companies at avoided cost. VIR are the avoided cost rates established for each electric company that reflect the unique characteristics of solar participants in the pilot programs. (PGE.)

a. Positions of the parties.

PGE made this proposal in its opening comments, asserting,

> [i]t may be possible to establish avoided cost rates that are specifically adjusted to the factors enumerated by PURPA that would reflect the unique characteristics of solar participants in the pilot. When adjusted, these payments may be both a proper reflection of the resources avoided by solar facilities, and adequate to facilitate such solar development.[60]

b. The Commission has jurisdiction to establish avoided cost rates, but it is unlikely it can establish rates that are sufficiently high to be effective VIR.

It is unequivocal that the Commission has authority to set avoided cost rates for energy purchased from QFs. However, the Commission has limited authority to adjust the avoided cost rate to reflect the unique characteristics of solar participants in the VIR Pilot Programs. Accordingly, staff does not believe that the Commission would be able to establish avoided cost rates that will adequately test the use of VIR to incent solar development.

Avoided costs are based on the utilities' costs, not those of the generators. And, FERC has been clear that a state may not set a resource-specific avoided cost. Meaning, a state cannot determine a utility's avoided cost rate for a purchase from a solar facility by determining what it would cost the utility to make the same purchase from another solar facility:

> [U]nder PURPA, an avoided cost (incremental cost) determination must permit QFs to participate in a non-discriminatory fashion, and at the same time, assure that the purchasing utility pays no more than the cost it otherwise would incur to generate the capacity (or energy) itself or "*purchase from another source*" (the language of section 210 of PURPA, emphasis added). Congress in this language did not in anyway limit the sources to be considered. The consequence is that regardless of whether the State regulatory authority determined avoided cost administratively, through competition solicitation (bidding), or some combination thereof, it must in its process reflect prices available from *all sources* able to sell to the utility whose avoided cost is being

[60] PGE Opening Comments 3.

determined. If the state is determining avoided cost by relying on a combination of benchmark and bidding procedures, as here, this means that the bidding cannot be limited to certain sellers (QFs); rather it must be all-source bidding. [61]

Furthermore, while a state may include environmental costs in a utility's avoided costs, it may do so only to the extent those costs are real costs the utility would incur when generating the energy itself or purchasing it from another source.[62]

Notably, a state may influence what costs are incurred by a utility, e.g., through a tax on certain types of resources or fuel. Also, the state's imposition of a capacity standard for certain resources could potentially impact a utility's avoided costs. While the SCS may ultimately impact Oregon utilities' avoided cost rates, such an impact would not be immediate because the utilities have several years to comply. Accordingly, it would be difficult for the Commission to use the utilities' obligation to comply with the SCS to inflate utilities' avoided costs in the near term.

Option 3d: Participants become QFs under PURPA and sell net output of energy generated by SPV facilities to electric companies at avoided cost. The ETO subsidizes sale price at VIR established by Commission.

a. Positions of the parties.

No party suggested this option in opening comments. However, several parties have contacted staff regarding this option and support it.

b. The Commission cannot require utilities to subsidize avoided cost rates.

The Commission does have authority to require utilities to compensate QF's for energy at a rate that exceeds avoided costs if the state offsets the purchase price with a subsidy or tax credit. However, the Commission does not have authority to require utilities to pay more than avoided costs for energy purchased from QFs. Accordingly, the Commission cannot offset the amounts paid by utilities in excess of the avoided cost cap with a subsidy funded directly by the utilities.

In *CGE Fulton, L.L.C.*, FERC concluded that the State of Illinois could order utilities to compensate QF's for energy at a rate that exceeded the purchasing utility's avoided cost when the state reimbursed the utility for payments that exceeded avoided cost using money that was not supplied by the utility or its ratepayers.[63] On reconsideration, FERC clarified that PURPA did not preclude a *state* from granting loans, subsidies or tax credits to particular facilities, including QFs, on environmental or other grounds, but that a state could not require *utilities* to pay a QF rates that exceeded the utility's avoided costs.[64]

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[61] *See Southern Cal. Edison*, 70 FERC 51,215 (1995 WL 169000) (emphasis in excerpt).

[62] 71 FERC 61,269 (1995 WL 327268).

[63] *CGE Fulton, L.L.C.* 70 FERC 61,290, (1995), on reconsideration 71 FERC 61,232

[64] The drafters of a National Renewable Energy Laboratory Technical Report released in January 2010, assert that FERC's order on reconsideration in *CGE, L.L.C.* stands for the proposition that states may use any source to subsidize avoided cost rates paid to a QF by a utility, even a source funded by utilities. Neither of FERC's orders in *CGE, L.L.C.* supports this proposition. In the first *CGE, L.L.C.* order, FERC concluded that it is permissible under PURPA for a state to require utilities to pay to QF rates in excess of avoided cost when the state reimbursed the utility with taxpayer money.

The conclusion that the state cannot require utilities to subsidize their own rates is supported by the Commission's decision in Southern California Edison, et al., in which FERC noted,

> With PURPA, Congress was seeking to diversify the Nation's generation fuel mix and promote more efficient use of fossil fuels when they were used for generation by encouraging renewable technologies and cogeneration, in order to cushion against further price shock and reduce dependence on fossil fuels. In promoting greater fuel diversity, however, Congress was not asking utilities and utility ratepayers to pay more than they otherwise would have paid for power. As we explained in the February 23 order, PURPA requires an electric utility to purchase power from a QF, but only if the QF sells at a price no higher than the cost the utility would have incurred for the power if it had not purchased the QF's energy and/or capacity, i.e. would have generated itself or purchased from another source. The intention was to make ratepayers indifferent as to whether the utility used more traditional sources of power or the newly-encouraged alternatives.
>
> * * * * *
>
> States may also seek to encourage renewable or other types of resources through their tax structure, or by giving direct subsidies. Use of the tax structure may allow states to affect the price of renewables or other alternatives. * *

Summary of recommended Commission actions in AR 538:

Adopt proposed Oregon Administrative Rules in Attachment A to this document.

Summary of recommended Commission actions in UM 1452:

1) Establish guidelines as recommended by Staff in these Final Comments:

- Defining "permanently installed"
- Implementing VIR bid option
- Establishing quality and reliability requirements for solar PV installations;
- Authorizing fee for capacity reservation application

On reconsideration, FERC concluded that PURPA did not preclude a state from subsidizing utility payments to QF with loans, subsidies, or tax credits, but that a state program that required utility to pay QFs rates in excess of avoided cost is inconsistent with PURPA. In other words, under these orders, a state cannot subsidize payments from utilities to QFs with subsidies paid for by the utilities.

The conclusion that states cannot require utilities to subsidize payments the utilities make to QF's under PURPA is supported by FERC's 1995 order on reconsideration in *Southern California Edison Company, et al.* 71 FERC 61,269, in which FERC reiterated that in enacting PURPA, Congress did not intend that utilities and utility ratepayers would shoulder the burden of facilitating renewable technologies.

2) Order that VIR Pilot Program capacity shall be allocated:

- To electric utilities based on their share of 2008 retail sales revenues, with 14.94 MW allocated to PGE, 9.8 MW allocated to PacifiCorp and 0.4 MW allocated to Idaho Power;
- to different participant classes as follows: 12 MW to small-scale; 8 MW to medium-scale; and 5 MW to large-scale. Each electric company shall allocate their proportionate share of the pilot program capacity accordingly;
- evenly in each year of the pilot programs, and unused capacity in any rate class will be rolled over into the capacity for that rate class for the following pilot year.

3) Adopt the VIR in Staff Table 1.

4) Order that PacifiCorp, PGE, and Idaho Power Company take the following actions recommended in Staff's Final Comments:

- File necessary tariffs and applications to implement VIR net-metering and bid options, semi-annual rate adjustment windows, the rate adjustment mechanism, and capacity reservation processes , and cost recovery mechanism that are recommended by Staff within 30 days of the Commission's order in UM 1452;
- Disclose information regarding available capacity prior consistently with Staff's recommendations;
- Submit to Commission draft within six months of the Commission's UM 1452 order.

5) Order that VIR Pilot Program applicants installing small-scale systems are:

- Eligible for VIR net-metering option in OAR 860-084-0100(2);
- Eligible for capacity reservation mechanism in OAR 860-084-0195(2)(a);

6) Order that VIR Pilot Program applicants installing medium-scale systems are:

- Eligible for VIR net-metering option in OAR 860-084-0100(2);
- Eligible for capacity reservation mechanism in OAR 860-084-0195(2)(b);

7) Order that VIR Pilot Program applicants with large-scale systems are:

- Eligible for VIR bid option in OAR 860-084-0100 (mechanism in OAR 860-084-0195(3);
- Eligible for capacity reservation mechanism in OAR 860-084-0195(2)(b);

8) Order that VIR Pilot Program applicants that are non-profit organizations installing systems with capacity no more than 100 kW are eligible for capacity reservation mechanism in OAR 860-084-0195(2)(a); and

9) Order that electric companies will recover VIR Pilot Program by deferring the costs under ORS 757.259 and amortization of the deferred amounts under ORS 757.210.

VII. Conclusion.

For the foregoing reasons, Staff recommends the Commission adopt Staff's proposed Oregon Administrative Rules to implement HB 3039 and also, take the recommended actions listed in section VI of these comments.

DATED this 17th day of February 2010.

Respectfully submitted,

JOHN R. KROGER
Attorney General

Stephanie S. Andrus, #92512
Senior Assistant Attorney General
Of Attorneys for Staff of the Public Utility
Commission of Oregon

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 a retail electricity customer executes a contract with an electric company for the delivery of energy under a volumetric incentive rate pilot program and the solar photovoltaic system is on-line.
(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) "Eligible energy" or "eligible generation" means the kilowatt hours that may be paid at the volumetric incentive rate. For the net metering option of the pilot program, eligible energy is equal to the actual annual usage of the retail electricity consumer in the year that the energy is generated by the eligible system. In a given month, this eligible energy is equal to the actual usage of the retail electricity

consumer for that month. For the bidding option of the pilot program, eligible energy equals actual generation, net of system requirements

(7) “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. An equipment package may include an integrated generator or electric production source.

(8) “Excess energy” or “excess generation” means the kilowatt hours generated in excess of actual annual usage under the net metering option of the volumetric incentive rate pilot program. In a given month, excess energy means kilowatt hours generated in excess of monthly usage.

(9) “Nameplate capacity” means the maximum rated output of a solar photovoltaic system, measured at an irradiance level of 1000 W/ m^2, with reference air mass 1,5 solar spectral irradiance distribution and cell or module junction temperature of 25°C.

(10) “Eligible participant” or “participant” means a retail electricity consumer receiving service at the property where the solar photovoltaic energy system will be installed. A regulated utility is not an eligible participant in pilot programs.

(11) "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.

(12) “On-line” means that the photovoltaic system is installed and providing power to the electric company’s electrical system or to serve the load of the retail electricity consumer.

(13) “Payable” generation is the eligible generation for each month plus accrued excess generation, up to the actual monthly usage. Excess generation accrues monthly. Accrued excess generation is the sum of generation remaining above the sum of payable generation. For the bidding option, payable generation is equal to eligible generation.

(14) “Pilot capacity limit” means the maximum installed capacity that each electric company may contract during the pilot program.

(15) “Pilot year” means each twelve-month period of the solar photovoltaic pilot program beginning on April 1, unless otherwise directed by the Commission 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.

(16) “Qualifying assignee” or “assignee” means third party to whom a retail electricity consumer may assign volumetric incentive rate payments under the standard contract. An electric company or its affiliate or any other regulated utility is not a qualifying assignee. Qualifying assignees 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.

(17) Qualifying "third party" or "third party" means a third party who is not a retail electricity consumer is the owner or operator of a photovoltaic system installed under the pilot program. An electric company or its affiliate or any other regulated utility is not a qualifying third party under the pilot programs.

(18)"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.

(19) "Reservation start date" means the date the retail electricity consumer is notified of securing capacity through a capacity reservation process and of the start and expiration dates for that capacity reservation. The reservation start date starts the clock for the time to interconnection agreement.

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

(21) "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. Retail electricity consumers include consumers on direct access. A regulated utility or its affiliate is not a retail electricity consumer.

(22) "Resource value" means the portion of the volumetric incentive rate that represents the estimated value to an electric company of the electricity delivered from the contracted system, associated with the 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 value of renewable energy certificates established under ORS 469A.130.

(23) "System requirements" means the input electricity required to allow the solar photovoltaic energy system to operate, sometimes referred to as the parasitic load.

(24) "Volumetric incentive payments" or "payments" means the monthly amount that an electric company pays to an eligible participant in the solar photovoltaic pilot program for payable energy generated by a contracted system.

(25) "Volumetric incentive rate" means the rate per kilowatt-hour paid by an electric company to a retail electricity consumer for payable energy generated by a contracted system.

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

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: 10.9 megawatts
(2) Pacific Power 8.7 megawatts
(3) Idaho Power Company: .4 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 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 convert 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. This conversion will be calculated as 85% of the manufacturer's nameplate rating.
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 execution date of any associated power purchase agreement; and
(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 860-083-0400.

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) Each electric company must establish pilot programs to demonstrate the use and effectiveness of volumetric incentive rates and payments for electricity delivered from qualifying solar photovoltaic energy systems.

(2) Each electric company must offer a net metering option under the pilot program. This option has the following characteristics:

a) Qualifying systems installed on the customer side of the service meter;
b) Volumetric incentive rates established by Commission Order;
c) Volumetric incentive rate payments for generation up to the actual annual usage of the retail electricity consumer (eligible generation); and
d) Generation in excess of net metered annual usage (excess generation) donated to the electric company's low income bill assistance program or sold by consumers eligible to sell electricity at wholesale at market-based rates.

(3) Capacity of qualifying systems sized to provide an estimated energy generation equal to 90 percent of the rolling average of the usage at the premises at which the qualifying system will be installed. If this average cannot be determined, the nameplate capacity can be no more than 90 percent of a rolling average of three year's usage by a similarly-situated customer, as determined by the electric company. The methodology used to calculate this energy generation will be consistent with methodologies used by the ETO and ODOE and will be defined by Commission Order.

(4) Each electric company must offer a volumetric incentive rate bid option under the pilot program. This option has the following characteristics:

a)_ Volumetric incentive rate paid to each retail electricity consumer is established by a successful bid for capacity in the volumetric incentive rate pilot program; and
b) Volumetric incentive rate payments for 100% of energy generated, net of system requirements.

(4) Retail electricity consumers eligible for each pilot program option will be defined by Commission Order.

(5) Capacity reservations in the solar photovoltaic pilot programs will be accepted 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 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 (2) must be:

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

(b)In compliance with the siting, design, interconnection, installation, and electric output standards and codes required by the laws of Oregon; (c) Installed with meters or other devices to monitor and measure the quantity of energy generated; (d) Permanently installed in the State of Oregon by a retail electricity consumer of the electric company;

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

(f) First operational and on-line afterthe launch of the pilot programs;

(g) Financed without expenditures under ORS 757.612 (3)(b)(B) or tax credits under ORS 469.160 or ORS 469.185 to 469.225;

(h) Certified by the residential electric consumer as constructed from new components (modules, inverter, batteries, mounting hardware, etc.); and

(i) Compliant with Commission quality and reliability requirements for photovoltaic systems and system installation.

(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) 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 during the contract term of the system, except that a 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 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 reserved systems 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. . Retail electricity consumers required to choose the net metering option of the volumetric pilot programs must connect their systems to the customer load side of their meter. Systems required to choose the volumetric incentive rate bidding option of the pilot program must connect into the distribution feeder that services the consumer at the property (3) A retail electricity consumer must be allowed to transfer their existing contract to another retail electricity consumer eligible to contract with the electric company under the pilot program and residing at the same address where the system is installed or who is moving the system to a new location under the same contract.

(4) Eligible systems may be owned, operated, or owned and operated by qualifying third parties, as 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)Operated by third parties on behalf of the retail electricity consumer.

(5) Ownership of Renewable Energy Certificates:

(a) For both options of the pilot programs,the electric company will own the rights to 100 percent of the renewable energy certificates that are allowed by the generation of energy by these contracted systems. For both options of the pilot programs, the renewable energy certificates will be substantiated by the generation meter. The electricity company may perfect the renewable energy certificates at its own expense.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 assignee under standard contracts approved by the Commission and must allow changes to assignment over the contract term.

(2) Electric companies may charge a reasonable fee for the assignment of payments, for account setup, at the time that the standard contract is assigned. Electric companies may charge a reasonable fee 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 after March 31, 2015, or when the cumulative capacity of contracted systems in pilot programs reaches 25 megawatts 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) Each electric company must convert 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. This conversion will be calculated as 85% of the manufacturer's nameplate rating.

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(5), as established by Commission Order.

(2) An electric company will not solicit or accept additional capacity reservations for a solar photovoltaic pilot program once 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 Annual Capacity 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.

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

(b) Medium-scale systems have nameplate capacities greater than 10 kilowatts and less than or equal to100 kilowatts; and

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

(3) Small-scale systems must be targeted to attain a goal of 75 percent of the energy generated under the solar photovoltaic pilot program, unless otherwise directed by the Commission.

(4) Distributing Capacity: At the start of each pilot program year, beginning in 2010, an electric company must allocate certain percentages of its annual pilot capacity allocation, established in OAR 860-084-0180, for small-scale, medium-scale , and large-scale capacity systems. The Commission will establish these percentages, by Order, and may change these percentages during the pilot program.

(5) 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 small-scale systems.

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

860-084-0195
Mechanisms for Reserving Capacity

(1) The mechanism for reserving capacity will vary by system capacity size, unless otherwise directed by Commission Order. The Commission will, by Order, assign a capacity reservation mechanism to each system capacity class. These assignments may change over the pilot programs.

(2) Mechanisms to distribute capacity and establish capacity reservations include the following:

(a) Application packages for capacity are submitted to the electric company at any time during the pilot year. Capacity is reserved for eligible retail electricity consumers, on a first-come, first-served basis, until the annual capacity limit for this system size is reached. Under this mechanism, a capacity reservation starts when an application package meeting the requirements of OAR 860-084-0230 (2) is received by the electric company.

(b) Application packages for capacity reservation are submitted to the electric company at any time during the pilot year. Capacity is reserved for eligible retail electricity consumers at the time the application is received. If the annual capacity limit for this system size has been reached, capacity is allocated from the following year's capacity allocation. No more than 2% of pilot program capacity may be utilized from the following year's capacity allocation, unless otherwise directed by the Commission. Under this mechanism, a capacity reservation starts when an application package meeting the requirements of OAR 860-084-0230 (2) is received by the electric company.

(c) Solicitations for capacity reservations are made by electric companies two months before the start of each pilot year, or as otherwise directed by the Commission. Application packages meeting the requirements of OAR 860-084-0230 (2) for capacity are submitted to the electric company during the first month of each pilot year, unless otherwise directed by Commission Order. If capacity reservation applications received during this application month over-subscribe available capacity, capacity must be awarded to retail electricity consumers whose applications meet established criteria, by random drawing. This drawing will take place on the first business day of the second month of the pilot year until the annual capacity limit for the system size is reached. Drawings must be carried out according to processes that comply with Commission guidelines. If capacity remains available after reservations are made for all consumers whose applications meet established criteria, the electric company continues to solicit applications and make capacity reservations, on a first-come, first-served basis over the pilot year, until the annual capacity limit for the size class is reached. If a rush of applications creates uncertainty as to which applications were received first, this uncertainty will be resolved by a random drawing process that complies with Commission guidelines. A capacity reservation starts when the consumer is notified that capacity has been secured for their project through the capacity distribution process.

(c) A Request for Proposal, approved by the Commission for bidding processes under the volumetric incentive pilot programs, is issued by the electric companies, during the month preceding the start of each pilot year, or as otherwise directed by the Commission. The Commission may require that this Request for Proposal include a bid cap. The Request for Proposal solicits responses with a deadline of thirty days from the date of issuance, with capacity awarded fifteen days later, unless otherwise directed by Commission Order. If capacity remains available after all bids that meet established criteria are awarded, this capacity will roll over into the next pilot year. Otherwise, 100% of the capacity offered will be awarded in the bidding process. A capacity reservation begins when the retail electricity consumer receives notification of a successful bid.

(3) The total number of capacity reservations that can be made by a retail electricity consumer in the pilot program is limited, as follows:

(a) A retail electricity consumer eligible for the net metered option of the volumetric incentive rate pilots may reserve capacity in the pilot program for up to three eligible systems between the start of the pilot programs and March 31, 2015.

(b) A retail electricity consumer eligible for the volumetric incentive rate bid option of the volumetric incentive pilots may win up to 5 bids, totaling less than or equal to 15% of the total capacity allocated to systems eligible for the volumetric bid option over the course of the pilot program.

(c) No retail electricity consumer, developer or installer may reserve capacity, in total, between the net metered and volumetric incentive rate bidding options that exceeds 15% of the total capacity allocated to the volumetric incentive rate pilot programs.

(d) A retail electricity consumer, developer or installer who violates these rules will become ineligible for further participation in the pilot programs.

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

(1) A consumer that has made a capacity reservation under the net metered option may receive the volumetric incentive rate in place at the time of the consumer's capacity reservation for 100% of the

eligible energy generated by the consumer's system. Capacity reservation applications and 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. Standard contracts must also identify the market rate index that will be used to establish rates paid to retail electricity consumers eligible to sell their excess energy at wholesale at market-based rates and that elect to do so.

(2) Reserved systems eligible for the volumetric bidding option are eligible for the volumetric incentive rate bid by the retail electricity consumer, to be paid on 100% of the energy generated by the contracted system, net of system requirements. Capacity reservation applications or standard contracts provided to these retail electricity consumers must communicate the successful volumetric incentive rate bid awarded to the retail electricity consumer.

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 consumers that may reserve capacity at any time during the year, a reservation expires twelve months from the reservation start date or if a completed interconnection agreement is not filed within two months of the reservation start date, unless otherwise directed by Commisson Order.

(b) For other consumers awarded capacity, a capacity 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. This capacity reservation will also expire if a completed interconnection agreement is not filed within two months of the reservation start date, unless otherwise directed by Commission Order.

(2) Electric companies must collect data on the 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 and solicit applications for capacity reservation, no later than two months before the start of the pilot year, , unless otherwise directed by the Commission. Each company must announce when the capacity allocation for the year is fully reserved.

(2) Capacity allocated to smaller systems that is not reserved in a pilot year must be added to the available capacity for smaller systems in the next pilot year and capacity allocated to medium and large systems that is not reserved in a pilot year must be added to the available capacity for medium and large 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 from smaller 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 for both the net metering and volumetric incentive rate bid option. The electric company must provide instruction to enable retail electricity consumers to generate capacity applications that meet the established criteria. Fees collected during the capacity application process are to be refunded to the retail electricity consumer if a capacity reservation is not secured.

(2)For the purposes of these rules, an application package includes a capacity reservation application, payment of fees required under OAR 860-084-0270, and an interconnection application that complies with OAR 860-084-0270 (4) (a), (c), (d), (f), and (g), unless otherwise directed by the Commission. Electric companies may not require the information required by OAR 860-084-0270 (4) (b) and OAR 860-084 (4) (e) as part of this initial application package.

(3)Within two months of securing a capacity reservation, a retail electricity consumer must submit a completed application for interconnection that meets all the requirements of OAR 860-084-0270 and that includes an estimate of annual system energy generation using the methodology identified in OAR 860-084-0010(2)(e).(3) The capacity reservation application must certify that the retail electricity consumerhas read and understands 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 as part of its volumetric incentive rate tariff filing. All transactions under the volumetric incentive rate pilot programs must be governed by a single contract.

(a) The standard contract will establish an agreement between the electric company and a retail electricity consumer under which the electric company will make volumetric rate incentive payments to participants for energy generated by solar photovoltaic systems installed in the service territory of the electric company and used by the participant under the net-metering option and for energy or transmitted to the electric company by the participant under the bid option.

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

(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. Each standard contract must be based on the volumetric incentive rate *(bid option)* or volumetric incentive rate formula *(net metering option)* in place at the time of the capacity reservation for the retail electricity consumer;

(c) Excess Energy Option. Each standard contract must allow a retail electricity consumer installing capacity under the net metered option to donate excess generation to the low income bill assistance program of the electric company or to sell this excess generation to the electric company at a market-based rate. Standard contracts must provide for certification by the retail electricity consumer that they are eligible to make wholesale sales of energy at market-based rates;

(d) Contract term and termination option. Each standard contract must include a date of initiation and a date of contract expiration.

(e) 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, and meet Commission quality, reliability, and installation requirements.

(f) Agreement to release information about participation. Each standard contract must include a provision under which the retail electricity consumer agrees that the electric company can 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.

(g) Agreement to participate. Each standard contract must require the retail electricity consumer to agree to complete up to three surveys on the effectiveness of the pilot programs in order to remain eligible for participation in the pilot program. Each standard contract must also includethe retail electricity consumer’s agreement that the electric company may release information obtained from the surveys to the Public Utility Commission and the Energy Trust of Oregon.

(h) Preferred payment option. Each standard contract must specify whether the retail electricity consumer elects to have the payment and billing be aggregated on a single bill or elects to be paid monthly through direct payment. The default payment method must be aggregation on a single bill with 100% of bill credit payable at the end of each month.

(i) Assignment of payment. Each standard contract must allow a retail electricity consumer to assign payments to a qualifying assignee. Contracts must allow changes of assignee over the contract term.

(j) 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 contract with the electric company under the pilot program, consistent with OAR 860-084-0130 (3). At the time of transfer of the contract, the retail electricity consumer must certify that this contract, when aggregated with other contracts owned or transferred to the retail electricity consumer does not create a violation of capacity distribution guidelines under OAR 860-084-0195(3).

(k) Disclosure that payments under the volumetric incentive rate bid option may be taxable as income, under Oregon and Federal Tax law, and that an eligible system may be ubject to property tax in the State of Oregon. (l) Name and business address of solar installer or contractor, name and business address of system financer, and description of the PV equipment package. The solar installer, contractor or developer must certify that this contract when aggregated with other contracts under the pilot programs does not account for more than 15% of the capacity under the pilot program.(m) For net-metered systems, participants must certify that the system is sized such that their qualifying system complies with OAR 860-084-0010(2)(e).

(4) A retail electricity consumer, contractor, financer or developer found by the Commission to have made a false certification is no longer eligible for the VIR Pilot Programs and any contract the consumer may have entered into is void.

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

860-084-0250
Billing and Payment Requirements

(1) Volumetric incentive payments for payable energy must be made monthly. Retail electricity consumers may request that:

(a) 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

(b) Payments for energy generated be netted against the retail electricity consumer's standard monthly bill and the retail electricity consumer receive or pay the resulting amount; or

(c) The qualified assignee given on the standard contract be paid 100% of the volumetric incentive rate payment and the retail electricity consumer be billed separately for the retail electricity consumer's monthly bill.

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) 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 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 is a complete equipment package that has been submitted by a manufacturer to a nationally recognized testing and certification laboratory, and 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 week 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 an application, or other fee, unless otherwise directed by the Commission. However, if an application for Level 1 interconnection review is denied because it does not meet the requirements for Level 1 interconnection review, and the applicant resubmits the application under another review procedure, the electric company may impose a fee for the resubmitted application, consistent with this section..

(2) For a Level 2 interconnection review, the electric company may charge fees of up to $50.00 plus $1.00 per kilowatt of the qualifying system's capacity, plus the reasonable cost of any required minor modifications to the electric distribution system or additional review. Costs for such minor modifications or additional review will be based on the electric company's non-binding, good faith estimates and the ultimate actual installed costs. Costs for engineering work done as part of any additional review will not exceed $100.00 per hour. An electric company may adjust the $100.00 hourly rate once in January of each year to account for inflation and deflation as measured by the Consumer Price Index.

(3) For a Level 3 interconnection review, the electric company may charge fees of up to $100.00 plus $2.00 per kilowatt of the qualifying system's capacity, as well as charges for actual time spent on any required impact or facilities studies. Costs for engineering work done as part of an impact study or interconnection facilities study will not exceed $100.00 per hour. An electric company may adjust the $100.00 hourly rate once in January of each year to account for inflation and deflation as measured by the Consumer Price Index. If the electric company must install facilities in order to accommodate the interconnection of the qualifying system, the cost of such facilities will be the responsibility of the applicant.

(4) Interconnected net-metered systems must be equipped with two meters; metering equipment that can measure the flow of electricity in both directions (complying with ANSI C12.1 standards and OAR 860-023-0015) to replace the existing customer meter, and a second meter that can measure the total output of the qualifying system. Interconnected stand-alone systems using the bidding process must be equipped with metering equipment that can measure the flow of electricity in both directions (complying with ANSI C12.1 standards and OAR 860-023-0015). The electric company will install the required metering equipment at the utility's expense for both the net-metered and stand-alone system

(a) The electric company constructs, owns, operates, and maintains all meters and applicable interconnection facilities on the company side of the retail electric consumers meter, including, the second meter installed to measure the total output of the qualifying system. The electric company may charge an additional monthly service charge to the retail electricity customer for the additional meter used to measure the total output of the qualifying system, as established by Commission order.

(5) An eligible participantwho 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 facilities, required additions or 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

860-084-0300
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 will include a non-binding, good faith cost estimate. 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 will send the applicant an interconnection agreement that details the scope of the necessary modifications and a non-binding, good faith estimate of its cost; or

(b) Substantial modifications to the electric company's electric distribution system are necessary to accommodate the proposed interconnection. In such a case, the electric company must provide a non-binding, good faith estimate of the cost of the modifications, which must be accurate to within plus or minus 25 percent. In addition, the electric company must offer to conduct, at the applicant's expense, an interconnection facilities study that must identify the types and cost of equipment needed to safely interconnect the applicant's net metering facility.

(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 the execution by the applicant of the interconnection facilities study agreement, the electric company will conduct an interconnection facilities study to identify the facilities necessary to safely interconnect the net metering facility with the electric company's electric distribution system, and 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 net metering facility to safely interconnect with the electric company's electric distribution system, and must include a non-binding, good faith estimate of the cost of those facilities and the estimated time required to build and install those facilities.

(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 net metering facility (unless the electric company does not so require), 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 net metering facility, and agree to pay the public utility the actual installed cost of the facilities needed to interconnect as identified in the interconnection facilities study.

(9) 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.

(10) 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.

(11) 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.

(4) The retail electric customers' electric service may be disconnected by the public utility entirely if

the net metering facility must be physically disconnected for any reason.

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 and Payments – Net Metering Option

(1) A retail electricity consumer participating in the volumetric incentive rate formula option under a pilot program receives payments for the electricity generated from the consumer's contracted system to meet the retail electricity consumer's annual load, as follows:

(a) For 15 years from the date of the consumer's date of enrollment, the payment equals the product of payable generation and the applicable volumetric incentive rate, with the applicable rate determined from rates or through a rate formula in a rate schedule in effect at the date of capacity reservation. Payable generation is the eligible generation for each month plus accrued excess generation, up to the actual monthly usage. Excess generation accrues monthly. Accrued excess generation is the sum of generation remaining above the sum of payable generation.

(b) *At the end of a generation year, established to end March 31st of each year, excess accrued energy will be either be sold at market rates or donated to the electric company account dedicated to low income bill assistance (valued at the avoided cost rate of the electric company).* (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 may establish initial volumetric incentive rates to enable participation in the pilot programs. (4) The Commission may periodically consider adjusting rates to meet targeted levels of participation as follows:

(a) The Commission may establish a formula, by Order, for rate adjustment The Commission may adjust rates, based on this formula, or may postpone adjustment of rates.

(b) Commission staff must make its recommendations for adjustment 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

860-084-0365
Volumetric Incentive Rate Bidding Option

(1) For 15 years from the date of the consumer's date of enrollment, a retail electricity consumer installing a system under the volumetric incentive rate bidding option of the pilot program, receives a payment which equals the product of the eligible kilowatt-hours of electricity delivered to the electric company and the volumetric incentive rate per kilowatt-hour established through the consumer's successful bid in the volumetric incentive rate bidding process that secured a capacity reservation.

(2) Each company will conduct a volumetric incentive rate bidding process with capacity awarded in the second month of each pilot year, or as otherwise directed by the Commission, through a Request for Proposal process approved by the Commission.

(3) The Commission will periodically consider adjusting requirements for the volumetric incentive rate bidding processes:

(a) Commission staff will consult with interested parties and may make a recommendation at a public meeting regarding the need to modify the volumetric incentive rate bidding processes or make other changes in the pilot programs.

(b) Commission staff will make any recommendations in time to allow process or program changes to occur by January 1, 2011 and every year 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.

(3) A resource value may be established for smaller, medium and large systems and may be differentiated by remote location or location central to the system load, as directed by the Commission.

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,

, and

(b) 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 of pilot program participation, for each customer class, 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 inverters, other hardware, labor, overhead, and regulatory compliance costs);
(5) Total financing cost;
(6) Financing terms (including fees paid, loan term, and interest rate secured)
(7) System location, including street address and GPS 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

(1) **860-084-0410:**
Contracting of Pilot Program Overhead Each electric company may enter into a contract with the Energy Trust of Oregon to provide data collection services required by OAR 860-084-0400.

(2) Each electric company may enter into a contract with the Energy Trust of Oregon to carry out the responsibilities required by OAR 860-084-0420 through OAR 860-084-0440.

860-084-0420
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:

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 system contracted in the solar photovoltaic pilot program,

b) The system and its components are new and have not been previously installed

c) The participant will comply with Commission requirements for system quality and reliability, quality of photovoltaic system installation, and qualifications of installers, and

d) The participant agrees to the confidential release of information from participant surveys and pilot program applications to the organizations given in section (2) of this rule.

(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 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 system
(d) Nameplate capacity of installed system;
(e) Name, business name and business address of contractor installing system;
(f) Financer of system;
(g) In-service date; and
(h) 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 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 develop and submit for Commission-approval, evaluations of solar photovoltaic pilot programs 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 understand participant decision processes in choosing between the volumetric incentive rate program and the existing net-metering program, and

(c) Comments on Commission recommendations for regulatory policy changes that may 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.

d) Additions to the list of required data to be collected under OAR 860-084-0400.

(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

;TAFF VIR RATES BY RATE CLASS AND PROJECT SIZE CATEGORY -- STEP0
ƷTO SOLAR PV DATA 2008-2009

?ERIOD = 15, COUNTY CLASS = 2, TSRF = 1.00, DEGRADATION = 1.00
;OAN FEE = 0.00, INSURANCE = 0.0000, METER SERVICE = 0, TAX CALC = 0, TAX PREP = 0

[he MEANS Procedure

ꝛate Class=1 Project Size Category=0 - 10 KW

Variable	Label	N	10th Pctl	25th Pctl	50th Pctl	Mean
System_Cost	System Cost ($)	160	18000.00	20299.00	24371.00	28745.43
DC_CAP	Capacity - DC (kW)	160	2.0000000	2.2000000	2.7150000	3.1456875
PUC_COST_WATT	System Cost per Watt ($/watt)	160	7.5167774	8.2072255	9.1664672	11.4909240
KWH_YEAR	Expected Annual Generation (kWh)	160	2160.00	2376.00	2932.20	3397.34
CF_YEAR	Annual Capacity Factor (%)	160	12.3287671	12.3287671	12.3287671	12.3287671
LPC_TSRF_DEG	County LPC x TSRF x Degradation	160	1.0800000	1.0800000	1.0800000	1.0800000
CMTR	Combined Marginal Tax Rate	0	.	.	.	.
VIR_600	Volumetric Incentive Rate at 6.00% ($/kWh)	160	0.5016331	0.5477102	0.6117253	0.7668482
VIR_650	Volumetric Incentive Rate at 6.50% ($/kWh)	160	0.5181492	0.5657434	0.6318662	0.7920965
VIR_700	Volumetric Incentive Rate at 7.00% ($/kWh)	160	0.5349178	0.5840523	0.6523150	0.8177307
VIR_750	Volumetric Incentive Rate at 7.50% ($/kWh)	160	0.5519338	0.6026312	0.6730654	0.8437431
VIR_800	Volumetric Incentive Rate at 8.00% ($/kWh)	160	0.5691918	0.6214745	0.6941111	0.8701256
VIR_850	Volumetric Incentive Rate at 8.50% ($/kWh)	160	0.5866867	0.6405764	0.7154455	0.8968701
VIR_900	Volumetric Incentive Rate at 9.00% ($/kWh)	160	0.6044131	0.6599310	0.7370622	0.9239684
VIR_950	Volumetric Incentive Rate at 9.50% ($/kWh)	160	0.6223654	0.6795323	0.7589545	0.9514122
VIR_1000	Volumetric Incentive Rate at 10.00% ($/kWh)	160	0.6405383	0.6993745	0.7811158	0.9791932

Rate Class=1 Project Size Category=10 - 100 KW

Variable	Label	N	10th Pctl	25th Pctl	50th Pctl	Mean
System_Cost	System Cost ($)	49	108513.00	141739.00	210672.00	278050.21
DC_CAP	Capacity - DC (kW)	49	12.3000000	17.3200000	31.4500000	36.0493878
PUC_COST_WATT	System Cost per Watt ($/watt)	49	6.1600000	6.1600000	7.6203488	7.7889997
KWH_YEAR	Expected Annual Generation (kWh)	49	13284.00	18705.60	33966.00	38933.34
CF_YEAR	Annual Capacity Factor (%)	49	12.3287671	12.3287671	12.3287671	12.3287671
LPC_TSRF_DEG	County LPC x TSRF x Degradation	49	1.0800000	1.0800000	1.0800000	1.0800000
CMTR	Combined Marginal Tax Rate	0	.	.	.	.
VIR_600	Volumetric Incentive Rate at 6.00% ($/kWh)	49	0.4110884	0.4110884	0.5085449	0.5197999
VIR_650	Volumetric Incentive Rate at 6.50% ($/kWh)	49	0.4246233	0.4246233	0.5252886	0.5369141
VIR_700	Volumetric Incentive Rate at 7.00% ($/kWh)	49	0.4383652	0.4383652	0.5422883	0.5542900
VIR_750	Volumetric Incentive Rate at 7.50% ($/kWh)	49	0.4523098	0.4523098	0.5595387	0.5719222
VIR_800	Volumetric Incentive Rate at 8.00% ($/kWh)	49	0.4664528	0.4664528	0.5770346	0.5898053
VIR_850	Volumetric Incentive Rate at 8.50% ($/kWh)	49	0.4807898	0.4807898	0.5947705	0.6079338
VIR_900	Volumetric Incentive Rate at 9.00% ($/kWh)	49	0.4953166	0.4953166	0.6127411	0.6263021
VIR_950	Volumetric Incentive Rate at 9.50% ($/kWh)	49	0.5100285	0.5100285	0.6309408	0.6449046
VIR_1000	Volumetric Incentive Rate at 10.00% ($/kWh)	49	0.5249212	0.5249212	0.6493641	0.6637356

;TAFF VIR RATES BY RATE CLASS AND PROJECT SIZE CATEGORY -- STEP0
;TO SOLAR PV DATA 2008-2009

ERIOD = 15, COUNTY CLASS = 2, TSRF = 1.00, DEGRADATION = 1.00
OAN FEE = 0.00, INSURANCE = 0.0000, METER SERVICE = 0, TAX CALC = 0, TAX PREP = 0

he MEANS Procedure

tate Class=2 Project Size Category=0 - 10 KW

Variable	Label	N	10th Pctl	25th Pctl	50th Pctl	Mean
System_Cost	System Cost ($)	82	16742.32	18677.00	25926.50	29667.67
DC_CAP	Capacity - DC (kW)	82	2.0000000	2.2800000	2.9650000	3.6210976
PUC_COST_WATT	System Cost per Watt ($/watt)	82	6.9122807	7.6583618	8.2000000	8.2556576
KWH_YEAR	Expected Annual Generation (kWh)	82	2280.00	2599.20	3380.10	4128.05
CF_YEAR	Annual Capacity Factor (%)	82	13.0136986	13.0136986	13.0136986	13.0136986
LPC_TSRF_DEG	County LPC x TSRF x Degradation	82	1.1400000	1.1400000	1.1400000	1.1400000
CMTR	Combined Marginal Tax Rate	0	.	.	.	.
VIR_600	Volumetric Incentive Rate at 6.00% ($/kWh)	82	0.4370134	0.4841827	0.5184265	0.5219454
VIR_650	Volumetric Incentive Rate at 6.50% ($/kWh)	82	0.4514019	0.5001243	0.5354956	0.5391303
VIR_700	Volumetric Incentive Rate at 7.00% ($/kWh)	82	0.4660104	0.5163095	0.5528256	0.5565779
VIR_750	Volumetric Incentive Rate at 7.50% ($/kWh)	82	0.4808344	0.5327336	0.5704112	0.5742828
VIR_800	Volumetric Incentive Rate at 8.00% ($/kWh)	82	0.4958693	0.5493913	0.5882470	0.5922397
VIR_850	Volumetric Incentive Rate at 8.50% ($/kWh)	82	0.5111105	0.5662776	0.6063276	0.6104430
VIR_900	Volumetric Incentive Rate at 9.00% ($/kWh)	82	0.5265534	0.5833872	0.6246474	0.6288872
VIR_950	Volumetric Incentive Rate at 9.50% ($/kWh)	82	0.5421932	0.6007151	0.6432007	0.6475664
VIR_1000	Volumetric Incentive Rate at 10.00% ($/kWh)	82	0.5580250	0.6182558	0.6619820	0.6664752

tate Class=2 Project Size Category=10 - 100 KW

Variable	Label	N	10th Pctl	25th Pctl	50th Pctl	Mean
System_Cost	System Cost ($)	21	82643.00	99864.00	167365.00	195684.82
DC_CAP	Capacity - DC (kW)	21	10.6400000	12.9600000	21.6000000	25.6061905
PUC_COST_WATT	System Cost per Watt ($/watt)	21	6.1600000	7.2456019	7.7380952	7.6820782
KWH_YEAR	Expected Annual Generation (kWh)	21	12129.60	14774.40	24624.00	29191.06
CF_YEAR	Annual Capacity Factor (%)	21	13.0136986	13.0136986	13.0136986	13.0136986
LPC_TSRF_DEG	County LPC x TSRF x Degradation	21	1.1400000	1.1400000	1.1400000	1.1400000
CMTR	Combined Marginal Tax Rate	0	.	.	.	.
VIR_600	Volumetric Incentive Rate at 6.00% ($/kWh)	21	0.3894521	0.4580869	0.4892237	0.4856821
VIR_650	Volumetric Incentive Rate at 6.50% ($/kWh)	21	0.4022747	0.4731692	0.5053312	0.5016731
VIR_700	Volumetric Incentive Rate at 7.00% ($/kWh)	21	0.4152934	0.4884822	0.5216850	0.5179084
VIR_750	Volumetric Incentive Rate at 7.50% ($/kWh)	21	0.4285040	0.5040210	0.5382800	0.5343833
VIR_800	Volumetric Incentive Rate at 8.00% ($/kWh)	21	0.4419026	0.5197809	0.5551111	0.5510926
VIR_850	Volumetric Incentive Rate at 8.50% ($/kWh)	21	0.4554851	0.5357571	0.5721732	0.5680312
VIR_900	Volumetric Incentive Rate at 9.00% ($/kWh)	21	0.4692473	0.5519446	0.5894611	0.5851939
VIR_950	Volumetric Incentive Rate at 9.50% ($/kWh)	21	0.4831849	0.5683386	0.6069693	0.6025754
VIR_1000	Volumetric Incentive Rate at 10.00% ($/kWh)	21	0.4972938	0.5849339	0.6246927	0.6201704

STAFF VIR RATES BY RATE CLASS AND PROJECT SIZE CATEGORY -- STEP0
ETO SOLAR PV DATA 2008-2009

PERIOD = 15, COUNTY CLASS = 2, TSRF = 1.00, DEGRADATION = 1.00
LOAN FEE = 0.00, INSURANCE = 0.0000, METER SERVICE = 0, TAX CALC = 0, TAX PREP = 0

The MEANS Procedure

Rate Class=3 Project Size Category=0 - 10 KW

Variable	Label	N	10th Pctl	25th Pctl	50th Pctl	Mean
System_Cost	System Cost ($)	101	17280.00	19086.50	26542.00	30220.22
DC_CAP	Capacity - DC (kW)	101	2.0400000	2.2800000	3.2400000	3.7884158
PUC_COST_WATT	System Cost per Watt ($/watt)	101	7.1315789	7.5713472	8.0000000	8.1256269
KWH_YEAR	Expected Annual Generation (kWh)	101	2692.80	3009.60	4276.80	5000.71
CF_YEAR	Annual Capacity Factor (%)	101	15.0684932	15.0684932	15.0684932	15.0684932
LPC_TSRF_DEG	County LPC x TSRF x Degradation	101	1.3200000	1.3200000	1.3200000	1.3200000
CMTR	Combined Marginal Tax Rate	0	.	.	.	.
VIR_600	Volumetric Incentive Rate at 6.00% ($/kWh)	101	0.3893947	0.4134067	0.4368117	0.4436711
VIR_650	Volumetric Incentive Rate at 6.50% ($/kWh)	101	0.4022154	0.4270180	0.4511936	0.4582789
VIR_700	Volumetric Incentive Rate at 7.00% ($/kWh)	101	0.4152321	0.4408373	0.4657954	0.4731099
VIR_750	Volumetric Incentive Rate at 7.50% ($/kWh)	101	0.4284408	0.4548605	0.4806125	0.4881597
VIR_800	Volumetric Incentive Rate at 8.00% ($/kWh)	101	0.4418374	0.4690833	0.4956405	0.5034237
VIR_850	Volumetric Incentive Rate at 8.50% ($/kWh)	101	0.4554179	0.4835012	0.5108747	0.5188971
VIR_900	Volumetric Incentive Rate at 9.00% ($/kWh)	101	0.4691780	0.4981099	0.5263104	0.5345753
VIR_950	Volumetric Incentive Rate at 9.50% ($/kWh)	101	0.4831136	0.5129048	0.5419429	0.5504533
VIR_1000	Volumetric Incentive Rate at 10.00% ($/kWh)	101	0.4972204	0.5278815	0.5577675	0.5665264

Rate Class=3 Project Size Category=10 - 100 KW

Variable	Label	N	10th Pctl	25th Pctl	50th Pctl	Mean
System_Cost	System Cost ($)	7	67500.00	81300.00	97645.00	148775.71
DC_CAP	Capacity - DC (kW)	7	10.4600000	10.6600000	11.9600000	20.0514286
PUC_COST_WATT	System Cost per Watt ($/watt)	7	6.4531549	6.8959341	7.5277778	7.6801430
KWH_YEAR	Expected Annual Generation (kWh)	7	13807.20	14071.20	15787.20	26467.89
CF_YEAR	Annual Capacity Factor (%)	7	15.0684932	15.0684932	15.0684932	15.0684932
LPC_TSRF_DEG	County LPC x TSRF x Degradation	7	1.3200000	1.3200000	1.3200000	1.3200000
CMTR	Combined Marginal Tax Rate	0	.	.	.	.
VIR_600	Volumetric Incentive Rate at 6.00% ($/kWh)	7	0.3523517	0.3765281	0.4110277	0.4193471
VIR_650	Volumetric Incentive Rate at 6.50% ($/kWh)	7	0.3639528	0.3889252	0.4245607	0.4331539
VIR_700	Volumetric Incentive Rate at 7.00% ($/kWh)	7	0.3757312	0.4015118	0.4383005	0.4471719
VIR_750	Volumetric Incentive Rate at 7.50% ($/kWh)	7	0.3876834	0.4142840	0.4522430	0.4613966
VIR_800	Volumetric Incentive Rate at 8.00% ($/kWh)	7	0.3998056	0.4272380	0.4663839	0.4758237
VIR_850	Volumetric Incentive Rate at 8.50% ($/kWh)	7	0.4120942	0.4403698	0.4807189	0.4904488
VIR_900	Volumetric Incentive Rate at 9.00% ($/kWh)	7	0.4245453	0.4536752	0.4952435	0.5052674
VIR_950	Volumetric Incentive Rate at 9.50% ($/kWh)	7	0.4371552	0.4671504	0.5099533	0.5202749
VIR_1000	Volumetric Incentive Rate at 10.00% ($/kWh)	7	0.4499200	0.4807910	0.5248438	0.5354668

;TAFF VIR RATES BY RATE CLASS AND PROJECT SIZE CATEGORY -- STEP0
;TO SOLAR PV DATA 2008-2009

'ERIOD = 15, COUNTY CLASS = 2, TSRF = 1.00, DEGRADATION = 1.00
;OAN FEE = 0.00, INSURANCE = 0.0000, METER SERVICE = 0, TAX CALC = 0, TAX PREP = 0

'he MEANS Procedure

;ate Class=4 Project Size Category=0 - 10 KW

Variable	Label	N	10th Pctl	25th Pctl	50th Pctl	Mean
System_Cost	System Cost ($)	79	13980.00	15226.50	24477.30	28096.25
DC_CAP	Capacity - DC (kW)	79	2.0000000	2.0400000	3.0400000	3.3407595
PUC_COST_WATT	System Cost per Watt ($/watt)	79	6.5238095	7.0000000	7.9501401	8.0691551
KWH_YEAR	Expected Annual Generation (kWh)	79	2860.00	2917.20	4347.20	4777.29
CF_YEAR	Annual Capacity Factor (%)	79	16.3242009	16.3242009	16.3242009	16.3242009
LPC_TSRF_DEG	County LPC x TSRF x Degradation	79	1.4300000	1.4300000	1.4300000	1.4300000
CMTR	Combined Marginal Tax Rate	0	.	.	.	.
VIR_600	Volumetric Incentive Rate at 6.00% ($/kWh)	79	0.3288088	0.3528095	0.4006978	0.4066963
VIR_650	Volumetric Incentive Rate at 6.50% ($/kWh)	79	0.3396348	0.3644256	0.4138907	0.4200867
VIR_700	Volumetric Incentive Rate at 7.00% ($/kWh)	79	0.3506262	0.3762193	0.4272852	0.4336817
VIR_750	Volumetric Incentive Rate at 7.50% ($/kWh)	79	0.3617798	0.3881870	0.4408773	0.4474773
VIR_800	Volumetric Incentive Rate at 8.00% ($/kWh)	79	0.3730920	0.4003250	0.4546628	0.4614692
VIR_850	Volumetric Incentive Rate at 8.50% ($/kWh)	79	0.3845595	0.4126296	0.4686375	0.4756531
VIR_900	Volumetric Incentive Rate at 9.00% ($/kWh)	79	0.3961787	0.4250969	0.4827971	0.4900247
VIR_950	Volumetric Incentive Rate at 9.50% ($/kWh)	79	0.4079461	0.4377232	0.4971372	0.5045794
VIR_1000	Volumetric Incentive Rate at 10.00% ($/kWh)	79	0.4198580	0.4505046	0.5116535	0.5193130

;ate Class=4 Project Size Category=10 - 100 KW

Variable	Label	N	10th Pctl	25th Pctl	50th Pctl	Mean
System_Cost	System Cost ($)	6	148000.00	170376.00	251050.00	261579.33
DC_CAP	Capacity - DC (kW)	6	18.3600000	21.6000000	28.9500000	30.2900000
PUC_COST_WATT	System Cost per Watt ($/watt)	6	7.4726316	7.9038282	8.3624099	8.5446577
KWH_YEAR	Expected Annual Generation (kWh)	6	26254.80	30888.00	41398.50	43314.70
CF_YEAR	Annual Capacity Factor (%)	6	16.3242009	16.3242009	16.3242009	16.3242009
LPC_TSRF_DEG	County LPC x TSRF x Degradation	6	1.4300000	1.4300000	1.4300000	1.4300000
CMTR	Combined Marginal Tax Rate	0	.	.	.	.
VIR_600	Volumetric Incentive Rate at 6.00% ($/kWh)	6	0.3766307	0.3983636	0.4214768	0.4306623
VIR_650	Volumetric Incentive Rate at 6.50% ($/kWh)	6	0.3890312	0.4114796	0.4353538	0.4448417
VIR_700	Volumetric Incentive Rate at 7.00% ($/kWh)	6	0.4016212	0.4247962	0.4494429	0.4592379
VIR_750	Volumetric Incentive Rate at 7.50% ($/kWh)	6	0.4143970	0.4383091	0.4637399	0.4738465
VIR_800	Volumetric Incentive Rate at 8.00% ($/kWh)	6	0.4273545	0.4520143	0.4782403	0.4886629
VIR_850	Volumetric Incentive Rate at 8.50% ($/kWh)	6	0.4404898	0.4659076	0.4929396	0.5036826
VIR_900	Volumetric Incentive Rate at 9.00% ($/kWh)	6	0.4537989	0.4799847	0.5078335	0.5189010
VIR_950	Volumetric Incentive Rate at 9.50% ($/kWh)	6	0.4672777	0.4942412	0.5229172	0.5343135
VIR_1000	Volumetric Incentive Rate at 10.00% ($/kWh)	6	0.4809221	0.5086729	0.5381862	0.5499153

STAFF VIR RATES BY RATE CLASS AND PROJECT SIZE CATEGORY -- STEP0
ETO SOLAR PV DATA 2008-2009

PERIOD = 15, COUNTY CLASS = 2, TSRF = 1.00, DEGRADATION = 1.00
LOAN FEE = 0.00, INSURANCE = 0.0000, METER SERVICE = 0, TAX CALC = 0, TAX PREP = 0

The MEANS Procedure

Project Size Category=0 - 10 KW

Variable	Label	N	10th Pctl	25th Pctl	50th Pctl	Mean
System_Cost	System Cost ($)	422	15226.50	19350.00	24946.58	29156.07
DC_CAP	Capacity - DC (kW)	422	2.0000000	2.1600000	3.0000000	3.4284123
PUC_COST_WATT	System Cost per Watt ($/watt)	422	7.0000000	7.6463675	8.2871558	9.4162638
KWH_YEAR	Expected Annual Generation (kWh)	422	2268.00	2721.60	3283.20	4181.40
CF_YEAR	Annual Capacity Factor (%)	422	12.3287671	12.3287671	13.0136986	13.8655349
LPC_TSRF_DEG	County LPC x TSRF x Degradation	422	1.0800000	1.0800000	1.1400000	1.2146209
VIR_600	Volumetric Incentive Rate at 6.00% ($/kWh)	422	0.3780101	0.4263633	0.5010028	0.5744906
VIR_650	Volumetric Incentive Rate at 6.50% ($/kWh)	422	0.3904560	0.4404012	0.5174981	0.5934055
VIR_700	Volumetric Incentive Rate at 7.00% ($/kWh)	422	0.4030922	0.4546537	0.5342457	0.6126096
VIR_750	Volumetric Incentive Rate at 7.50% ($/kWh)	422	0.4159147	0.4691164	0.5512402	0.6320970
VIR_800	Volumetric Incentive Rate at 8.00% ($/kWh)	422	0.4289197	0.4837849	0.5684766	0.6518616
VIR_850	Volumetric Incentive Rate at 8.50% ($/kWh)	422	0.4421031	0.4986547	0.5859495	0.6718975
VIR_900	Volumetric Incentive Rate at 9.00% ($/kWh)	422	0.4554609	0.5137212	0.6036536	0.6921984
VIR_950	Volumetric Incentive Rate at 9.50% ($/kWh)	422	0.4689891	0.5289798	0.6215834	0.7127582
VIR_1000	Volumetric Incentive Rate at 10.00% ($/kWh)	422	0.4826834	0.5444259	0.6397335	0.7335705

Project Size Category=10 - 100 KW

Variable	Label	N	10th Pctl	25th Pctl	50th Pctl	Mean
System_Cost	System Cost ($)	83	95772.00	123996.00	193116.00	245117.44
DC_CAP	Capacity - DC (kW)	83	11.5500000	15.1200000	28.5000000	31.6415663
PUC_COST_WATT	System Cost per Watt ($/watt)	83	6.1600000	6.8959341	7.6869919	7.8073925
KWH_YEAR	Expected Annual Generation (kWh)	83	13284.00	17236.80	31590.00	35733.85
CF_YEAR	Annual Capacity Factor (%)	83	12.3287671	12.3287671	12.3287671	13.0219508
LPC_TSRF_DEG	County LPC x TSRF x Degradation	83	1.0800000	1.0800000	1.0800000	1.1407229
VIR_600	Volumetric Incentive Rate at 6.00% ($/kWh)	83	0.4062854	0.4110884	0.4922631	0.4962521
VIR_650	Volumetric Incentive Rate at 6.50% ($/kWh)	83	0.4196622	0.4246233	0.5084707	0.5125910
VIR_700	Volumetric Incentive Rate at 7.00% ($/kWh)	83	0.4332436	0.4383652	0.5249261	0.5291797
VIR_750	Volumetric Incentive Rate at 7.50% ($/kWh)	83	0.4470252	0.4523098	0.5416242	0.5460132
VIR_800	Volumetric Incentive Rate at 8.00% ($/kWh)	83	0.4610030	0.4664528	0.5585600	0.5630861
VIR_850	Volumetric Incentive Rate at 8.50% ($/kWh)	83	0.4751725	0.4807898	0.5757281	0.5803933
VIR_900	Volumetric Incentive Rate at 9.00% ($/kWh)	83	0.4895295	0.4953166	0.5931233	0.5979295
VIR_950	Volumetric Incentive Rate at 9.50% ($/kWh)	83	0.5040696	0.5100285	0.6107403	0.6156893
VIR_1000	Volumetric Incentive Rate at 10.00% ($/kWh)	83	0.5187883	0.5249212	0.6285738	0.6336673

STAFF VIR RATES BY RATE CLASS AND PROJECT SIZE CATEGORY -- STEP1
ETO SOLAR PV DATA 2008-2009

PERIOD = 15, COUNTY CLASS = 3, TSRF = 1.00, DEGRADATION = 1.00
LOAN FEE = 0.00, INSURANCE = 0.0000, METER SERVICE = 0, TAX CALC = 0, TAX PREP = 0

The MEANS Procedure

Rate Class=1 Project Size Category=0 - 10 KW

Variable	Label	N	10th Pctl	25th Pctl	50th Pctl	Mean
System_Cost	System Cost ($)	242	16743.00	19898.00	24891.50	29057.92
DC_CAP	Capacity - DC (kW)	242	2.0000000	2.2400000	2.8650000	3.3067769
PUC_COST_WATT	System Cost per Watt ($/watt)	242	7.2372928	7.9226765	8.6877381	10.3946767
KWH_YEAR	Expected Annual Generation (kWh)	242	2200.00	2464.00	3151.50	3637.45
CF_YEAR	Annual Capacity Factor (%)	242	12.5570776	12.5570776	12.5570776	12.5570776
LPC_TSRF_DEG	County LPC x TSRF x Degradation	242	1.1000000	1.1000000	1.1000000	1.1000000
CMTR	Combined Marginal Tax Rate	0	.	.	.	.
VIR_600	Volumetric Incentive Rate at 6.00% ($/kWh)	242	0.4742002	0.5191077	0.5692359	0.6810775
VIR_650	Volumetric Incentive Rate at 6.50% ($/kWh)	242	0.4898131	0.5361992	0.5879778	0.7035018
VIR_700	Volumetric Incentive Rate at 7.00% ($/kWh)	242	0.5056646	0.5535519	0.6070062	0.7262689
VIR_750	Volumetric Incentive Rate at 7.50% ($/kWh)	242	0.5217500	0.5711606	0.6263154	0.7493718
VIR_800	Volumetric Incentive Rate at 8.00% ($/kWh)	242	0.5380643	0.5890199	0.6458992	0.7728034
VIR_850	Volumetric Incentive Rate at 8.50% ($/kWh)	242	0.5546024	0.6071242	0.6657518	0.7965566
VIR_900	Volumetric Incentive Rate at 9.00% ($/kWh)	242	0.5713594	0.6254681	0.6858671	0.8206240
VIR_950	Volumetric Incentive Rate at 9.50% ($/kWh)	242	0.5883300	0.6440458	0.7062388	0.8449983
VIR_1000	Volumetric Incentive Rate at 10.00% ($/kWh)	242	0.6055090	0.6628518	0.7268607	0.8696720

Rate Class=1 Project Size Category=10 - 100 KW

Variable	Label	N	10th Pctl	25th Pctl	50th Pctl	Mean
System_Cost	System Cost ($)	70	98901.25	125590.00	202575.00	253340.60
DC_CAP	Capacity - DC (kW)	70	12.1700000	15.3900000	29.7450000	32.9164286
PUC_COST_WATT	System Cost per Watt ($/watt)	70	6.1600000	6.1600000	7.6340321	7.7569232
KWH_YEAR	Expected Annual Generation (kWh)	70	13387.00	16929.00	32719.50	36208.07
CF_YEAR	Annual Capacity Factor (%)	70	12.5570776	12.5570776	12.5570776	12.5570776
LPC_TSRF_DEG	County LPC x TSRF x Degradation	70	1.1000000	1.1000000	1.1000000	1.1000000
CMTR	Combined Marginal Tax Rate	0	.	.	.	.
VIR_600	Volumetric Incentive Rate at 6.00% ($/kWh)	70	0.4036140	0.4036140	0.5001952	0.5082473
VIR_650	Volumetric Incentive Rate at 6.50% ($/kWh)	70	0.4169029	0.4169029	0.5166640	0.5249811
VIR_700	Volumetric Incentive Rate at 7.00% ($/kWh)	70	0.4303949	0.4303949	0.5333845	0.5419708
VIR_750	Volumetric Incentive Rate at 7.50% ($/kWh)	70	0.4440860	0.4440860	0.5503517	0.5592112
VIR_800	Volumetric Incentive Rate at 8.00% ($/kWh)	70	0.4579718	0.4579718	0.5675603	0.5766968
VIR_850	Volumetric Incentive Rate at 8.50% ($/kWh)	70	0.4720482	0.4720482	0.5850051	0.5944224
VIR_900	Volumetric Incentive Rate at 9.00% ($/kWh)	70	0.4863108	0.4863108	0.6026806	0.6123824
VIR_950	Volumetric Incentive Rate at 9.50% ($/kWh)	70	0.5007553	0.5007553	0.6205815	0.6305715
VIR_1000	Volumetric Incentive Rate at 10.00% ($/kWh)	70	0.5153772	0.5153772	0.6387023	0.6489840

STAFF VIR RATES BY RATE CLASS AND PROJECT SIZE CATEGORY -- STEP1
ETO SOLAR PV DATA 2008-2009

PERIOD = 15, COUNTY CLASS = 3, TSRF = 1.00, DEGRADATION = 1.00
LOAN FEE = 0.00, INSURANCE = 0.0000, METER SERVICE = 0, TAX CALC = 0, TAX PREP = 0

The MEANS Procedure

Rate Class=2 Project Size Category=0 - 10 KW

Variable	Label	N	10th Pctl	25th Pctl	50th Pctl	Mean
System_Cost	System Cost ($)	33	21600.00	25300.00	27720.00	30615.11
DC_CAP	Capacity - DC (kW)	33	2.3100000	3.1500000	3.8000000	3.8578788
PUC_COST_WATT	System Cost per Watt ($/watt)	33	7.0000000	7.3842807	7.9591837	8.0384119
KWH_YEAR	Expected Annual Generation (kWh)	33	2772.00	3780.00	4560.00	4629.45
CF_YEAR	Annual Capacity Factor (%)	33	13.6986301	13.6986301	13.6986301	13.6986301
LPC_TSRF_DEG	County LPC x TSRF x Degradation	33	1.2000000	1.2000000	1.2000000	1.2000000
CMTR	Combined Marginal Tax Rate	0	.	.	.	.
VIR_600	Volumetric Incentive Rate at 6.00% ($/kWh)	33	0.4204313	0.4435118	0.4780414	0.4828000
VIR_650	Volumetric Incentive Rate at 6.50% ($/kWh)	33	0.4342739	0.4581143	0.4937808	0.4986960
VIR_700	Volumetric Incentive Rate at 7.00% ($/kWh)	33	0.4483281	0.4729400	0.5097608	0.5148351
VIR_750	Volumetric Incentive Rate at 7.50% ($/kWh)	33	0.4625895	0.4879844	0.5259765	0.5312122
VIR_800	Volumetric Incentive Rate at 8.00% ($/kWh)	33	0.4770540	0.5032429	0.5424229	0.5478223
VIR_850	Volumetric Incentive Rate at 8.50% ($/kWh)	33	0.4917169	0.5187108	0.5590950	0.5646604
VIR_900	Volumetric Incentive Rate at 9.00% ($/kWh)	33	0.5065738	0.5343833	0.5759877	0.5817212
VIR_950	Volumetric Incentive Rate at 9.50% ($/kWh)	33	0.5216201	0.5502556	0.5930957	0.5989996
VIR_1000	Volumetric Incentive Rate at 10.00% ($/kWh)	33	0.5368513	0.5663229	0.6104140	0.6164902

Rate Class=2 Project Size Category=10 - 100 KW

Variable	Label	N	10th Pctl	25th Pctl	50th Pctl	Mean
System_Cost	System Cost ($)	3	67500.00	67500.00	95680.00	86941.67
DC_CAP	Capacity - DC (kW)	3	10.4600000	10.4600000	10.6600000	11.0266667
PUC_COST_WATT	System Cost per Watt ($/watt)	3	6.4531549	6.4531549	8.0000000	7.8710329
KWH_YEAR	Expected Annual Generation (kWh)	3	12552.00	12552.00	12792.00	13232.00
CF_YEAR	Annual Capacity Factor (%)	3	13.6986301	13.6986301	13.6986301	13.6986301
LPC_TSRF_DEG	County LPC x TSRF x Degradation	3	1.2000000	1.2000000	1.2000000	1.2000000
CMTR	Combined Marginal Tax Rate	0	.	.	.	.
VIR_600	Volumetric Incentive Rate at 6.00% ($/kWh)	3	0.3875869	0.3875869	0.4804929	0.4727469
VIR_650	Volumetric Incentive Rate at 6.50% ($/kWh)	3	0.4003481	0.4003481	0.4963130	0.4883120
VIR_700	Volumetric Incentive Rate at 7.00% ($/kWh)	3	0.4133043	0.4133043	0.5123749	0.5041150
VIR_750	Volumetric Incentive Rate at 7.50% ($/kWh)	3	0.4264517	0.4264517	0.5286738	0.5201511
VIR_800	Volumetric Incentive Rate at 8.00% ($/kWh)	3	0.4397862	0.4397862	0.5452045	0.5364154
VIR_850	Volumetric Incentive Rate at 8.50% ($/kWh)	3	0.4533036	0.4533036	0.5619622	0.5529028
VIR_900	Volumetric Incentive Rate at 9.00% ($/kWh)	3	0.4669999	0.4669999	0.5789415	0.5696084
VIR_950	Volumetric Incentive Rate at 9.50% ($/kWh)	3	0.4808707	0.4808707	0.5961372	0.5865270
VIR_1000	Volumetric Incentive Rate at 10.00% ($/kWh)	3	0.4949120	0.4949120	0.6135443	0.6036534

STAFF VIR RATES BY RATE CLASS AND PROJECT SIZE CATEGORY -- STEP1
ETO SOLAR PV DATA 2008-2009

PERIOD = 15, COUNTY CLASS = 3, TSRF = 1.00, DEGRADATION = 1.00
LOAN FEE = 0.00, INSURANCE = 0.0000, METER SERVICE = 0, TAX CALC = 0, TAX PREP = 0

The MEANS Procedure

Rate Class=3 Project Size Category=0 - 10 KW

Variable	Label	N	10th Pctl	25th Pctl	50th Pctl	Mean
System_Cost	System Cost ($)	92	17280.00	18488.78	25919.50	31496.76
DC_CAP	Capacity - DC (kW)	92	2.0400000	2.2800000	3.0900000	3.7725000
PUC_COST_WATT	System Cost per Watt ($/watt)	92	7.0635417	7.5603447	8.0000000	8.2972844
KWH_YEAR	Expected Annual Generation (kWh)	92	2652.00	2964.00	4017.00	4904.25
CF_YEAR	Annual Capacity Factor (%)	92	14.8401826	14.8401826	14.8401826	14.8401826
LPC_TSRF_DEG	County LPC x TSRF x Degradation	92	1.3000000	1.3000000	1.3000000	1.3000000
CMTR	Combined Marginal Tax Rate	0	.	.	.	.
VIR_600	Volumetric Incentive Rate at 6.00% ($/kWh)	92	0.3916133	0.4191568	0.4435319	0.4600138
VIR_650	Volumetric Incentive Rate at 6.50% ($/kWh)	92	0.4045070	0.4329574	0.4581351	0.4751596
VIR_700	Volumetric Incentive Rate at 7.00% ($/kWh)	92	0.4175979	0.4469690	0.4729615	0.4905370
VIR_750	Volumetric Incentive Rate at 7.50% ($/kWh)	92	0.4308818	0.4611872	0.4880066	0.5061411
VIR_800	Volumetric Incentive Rate at 8.00% ($/kWh)	92	0.4443548	0.4756078	0.5032657	0.5219674
VIR_850	Volumetric Incentive Rate at 8.50% ($/kWh)	92	0.4580127	0.4902263	0.5187343	0.5380107
VIR_900	Volumetric Incentive Rate at 9.00% ($/kWh)	92	0.4718512	0.5050381	0.5344075	0.5542664
VIR_950	Volumetric Incentive Rate at 9.50% ($/kWh)	92	0.4858662	0.5200388	0.5502805	0.5707293
VIR_1000	Volumetric Incentive Rate at 10.00% ($/kWh)	92	0.5000533	0.5352238	0.5663486	0.5873944

Rate Class=3 Project Size Category=10 - 100 KW

Variable	Label	N	10th Pctl	25th Pctl	50th Pctl	Mean
System_Cost	System Cost ($)	5	81300.00	154705.00	159600.00	190196.20
DC_CAP	Capacity - DC (kW)	5	10.8000000	17.5500000	22.8000000	26.0160000
PUC_COST_WATT	System Cost per Watt ($/watt)	5	6.8959341	6.9090909	7.4726316	7.5241068
KWH_YEAR	Expected Annual Generation (kWh)	5	14040.00	22815.00	29640.00	33820.80
CF_YEAR	Annual Capacity Factor (%)	5	14.8401826	14.8401826	14.8401826	14.8401826
LPC_TSRF_DEG	County LPC x TSRF x Degradation	5	1.3000000	1.3000000	1.3000000	1.3000000
CMTR	Combined Marginal Tax Rate	0	.	.	.	.
VIR_600	Volumetric Incentive Rate at 6.00% ($/kWh)	5	0.3823208	0.3830503	0.4142938	0.4171477
VIR_650	Volumetric Incentive Rate at 6.50% ($/kWh)	5	0.3949087	0.3956621	0.4279343	0.4308821
VIR_700	Volumetric Incentive Rate at 7.00% ($/kWh)	5	0.4076889	0.4084667	0.4417833	0.4448266
VIR_750	Volumetric Incentive Rate at 7.50% ($/kWh)	5	0.4206576	0.4214602	0.4558367	0.4589767
VIR_800	Volumetric Incentive Rate at 8.00% ($/kWh)	5	0.4338109	0.4346386	0.4700899	0.4733281
VIR_850	Volumetric Incentive Rate at 8.50% ($/kWh)	5	0.4471447	0.4479978	0.4845388	0.4878765
VIR_900	Volumetric Incentive Rate at 9.00% ($/kWh)	5	0.4606549	0.4615337	0.4991788	0.5026174
VIR_950	Volumetric Incentive Rate at 9.50% ($/kWh)	5	0.4743373	0.4752423	0.5140055	0.5175462
VIR_1000	Volumetric Incentive Rate at 10.00% ($/kWh)	5	0.4881878	0.4891192	0.5290143	0.5326584

STAFF VIR RATES BY RATE CLASS AND PROJECT SIZE CATEGORY -- STEP1
ETO SOLAR PV DATA 2008-2009

PERIOD = 15, COUNTY CLASS = 3, TSRF = 1.00, DEGRADATION = 1.00
LOAN FEE = 0.00, INSURANCE = 0.0000, METER SERVICE = 0, TAX CALC = 0, TAX PREP = 0

The MEANS Procedure

Rate Class=4 Project Size Category=0 - 10 KW

Variable	Label	N	10th Pctl	25th Pctl	50th Pctl	Mean
System_Cost	System Cost ($)	55	13700.00	14050.00	18000.00	24797.19
DC_CAP	Capacity - DC (kW)	55	2.0000000	2.0000000	2.1000000	3.1303636
PUC_COST_WATT	System Cost per Watt ($/watt)	55	6.5238095	6.9900000	7.5000000	7.8097056
KWH_YEAR	Expected Annual Generation (kWh)	55	2800.00	2800.00	2940.00	4382.51
CF_YEAR	Annual Capacity Factor (%)	55	15.9817352	15.9817352	15.9817352	15.9817352
LPC_TSRF_DEG	County LPC x TSRF x Degradation	55	1.4000000	1.4000000	1.4000000	1.4000000
CMTR	Combined Marginal Tax Rate	0	.	.	.	.
VIR_600	Volumetric Incentive Rate at 6.00% ($/kWh)	55	0.3358547	0.3598549	0.3861104	0.4020544
VIR_650	Volumetric Incentive Rate at 6.50% ($/kWh)	55	0.3469126	0.3717030	0.3988229	0.4152920
VIR_700	Volumetric Incentive Rate at 7.00% ($/kWh)	55	0.3581396	0.3837322	0.4117298	0.4287318
VIR_750	Volumetric Incentive Rate at 7.50% ($/kWh)	55	0.3695322	0.3959389	0.4248271	0.4423700
VIR_800	Volumetric Incentive Rate at 8.00% ($/kWh)	55	0.3810868	0.4083193	0.4381108	0.4562022
VIR_850	Volumetric Incentive Rate at 8.50% ($/kWh)	55	0.3928001	0.4208695	0.4515767	0.4702242
VIR_900	Volumetric Incentive Rate at 9.00% ($/kWh)	55	0.4046683	0.4335858	0.4652208	0.4844317
VIR_950	Volumetric Incentive Rate at 9.50% ($/kWh)	55	0.4166878	0.4464642	0.4790389	0.4988203
VIR_1000	Volumetric Incentive Rate at 10.00% ($/kWh)	55	0.4288549	0.4595009	0.4930267	0.5133857

Rate Class=4 Project Size Category=10 - 100 KW

Variable	Label	N	10th Pctl	25th Pctl	50th Pctl	Mean
System_Cost	System Cost ($)	5	148000.00	198000.00	304100.00	279820.00
DC_CAP	Capacity - DC (kW)	5	18.3600000	21.6000000	35.1000000	31.7880000
PUC_COST_WATT	System Cost per Watt ($/watt)	5	7.9038282	8.0610022	8.6638177	8.7590629
KWH_YEAR	Expected Annual Generation (kWh)	5	25704.00	30240.00	49140.00	44503.20
CF_YEAR	Annual Capacity Factor (%)	5	15.9817352	15.9817352	15.9817352	15.9817352
LPC_TSRF_DEG	County LPC x TSRF x Degradation	5	1.4000000	1.4000000	1.4000000	1.4000000
CMTR	Combined Marginal Tax Rate	0	.	.	.	.
VIR_600	Volumetric Incentive Rate at 6.00% ($/kWh)	5	0.4069000	0.4149915	0.4460253	0.4509287
VIR_650	Volumetric Incentive Rate at 6.50% ($/kWh)	5	0.4202971	0.4286550	0.4607106	0.4657754
VIR_700	Volumetric Incentive Rate at 7.00% ($/kWh)	5	0.4338989	0.4425274	0.4756203	0.4808490
VIR_750	Volumetric Incentive Rate at 7.50% ($/kWh)	5	0.4477014	0.4566043	0.4907500	0.4961450
VIR_800	Volumetric Incentive Rate at 8.00% ($/kWh)	5	0.4617003	0.4708816	0.5060949	0.5116587
VIR_850	Volumetric Incentive Rate at 8.50% ($/kWh)	5	0.4758913	0.4853548	0.5216505	0.5273852
VIR_900	Volumetric Incentive Rate at 9.00% ($/kWh)	5	0.4902700	0.5000195	0.5374118	0.5433198
VIR_950	Volumetric Incentive Rate at 9.50% ($/kWh)	5	0.5048321	0.5148711	0.5533740	0.5594575
VIR_1000	Volumetric Incentive Rate at 10.00% ($/kWh)	5	0.5195731	0.5299052	0.5695324	0.5757935

STAFF VIR RATES BY RATE CLASS AND PROJECT SIZE CATEGORY -- STEP1
ETO SOLAR PV DATA 2008-2009

PERIOD = 15, COUNTY CLASS = 3, TSRF = 1.00, DEGRADATION = 1.00
LOAN FEE = 0.00, INSURANCE = 0.0000, METER SERVICE = 0, TAX CALC = 0, TAX PREP = 0

The MEANS Procedure

Project Size Category=0 - 10 KW

Variable	Label	N	10th Pctl	25th Pctl	50th Pctl	Mean
System_Cost	System Cost ($)	422	15226.50	19350.00	24946.58	29156.07
DC_CAP	Capacity - DC (kW)	422	2.0000000	2.1600000	3.0000000	3.4284123
PUC_COST_WATT	System Cost per Watt ($/watt)	422	7.0000000	7.6463675	8.2871558	9.4162638
KWH_YEAR	Expected Annual Generation (kWh)	422	2222.00	2665.00	3300.00	4088.31
CF_YEAR	Annual Capacity Factor (%)	422	12.5570776	12.5570776	12.5570776	13.5904261
LPC_TSRF_DEG	County LPC x TSRF x Degradation	422	1.1000000	1.1000000	1.1000000	1.1905213
VIR_600	Volumetric Incentive Rate at 6.00% ($/kWh)	422	0.3930482	0.4435319	0.5127543	0.5810128
VIR_650	Volumetric Incentive Rate at 6.50% ($/kWh)	422	0.4059892	0.4581351	0.5296366	0.6001425
VIR_700	Volumetric Incentive Rate at 7.00% ($/kWh)	422	0.4191280	0.4729615	0.5467769	0.6195646
VIR_750	Volumetric Incentive Rate at 7.50% ($/kWh)	422	0.4324606	0.4880066	0.5641701	0.6392732
VIR_800	Volumetric Incentive Rate at 8.00% ($/kWh)	422	0.4459830	0.5032657	0.5818108	0.6592623
VIR_850	Volumetric Incentive Rate at 8.50% ($/kWh)	422	0.4596909	0.5187343	0.5996936	0.6795256
VIR_900	Volumetric Incentive Rate at 9.00% ($/kWh)	422	0.4735801	0.5344075	0.6178129	0.7000570
VIR_950	Volumetric Incentive Rate at 9.50% ($/kWh)	422	0.4876464	0.5502805	0.6361632	0.7208502
VIR_1000	Volumetric Incentive Rate at 10.00% ($/kWh)	422	0.5018856	0.5663486	0.6547390	0.7418988

Project Size Category=10 - 100 KW

Variable	Label	N	10th Pctl	25th Pctl	50th Pctl	Mean
System_Cost	System Cost ($)	83	95772.00	123996.00	193116.00	245117.44
DC_CAP	Capacity - DC (kW)	83	11.5500000	15.1200000	28.5000000	31.6415663
PUC_COST_WATT	System Cost per Watt ($/watt)	83	6.1600000	6.8959341	7.6869919	7.8073925
KWH_YEAR	Expected Annual Generation (kWh)	83	13310.00	16632.00	31350.00	35733.51
CF_YEAR	Annual Capacity Factor (%)	83	12.5570776	12.5570776	12.5570776	12.9421797
LPC_TSRF_DEG	County LPC x TSRF x Degradation	83	1.1000000	1.1000000	1.1000000	1.1337349
VIR_600	Volumetric Incentive Rate at 6.00% ($/kWh)	83	0.4036140	0.4036140	0.4959973	0.4980233
VIR_650	Volumetric Incentive Rate at 6.50% ($/kWh)	83	0.4169029	0.4169029	0.5123279	0.5144205
VIR_700	Volumetric Incentive Rate at 7.00% ($/kWh)	83	0.4303949	0.4303949	0.5289081	0.5310685
VIR_750	Volumetric Incentive Rate at 7.50% ($/kWh)	83	0.4440860	0.4440860	0.5457329	0.5479620
VIR_800	Volumetric Incentive Rate at 8.00% ($/kWh)	83	0.4579718	0.4579718	0.5627971	0.5650958
VIR_850	Volumetric Incentive Rate at 8.50% ($/kWh)	83	0.4720482	0.4720482	0.5800954	0.5824648
VIR_900	Volumetric Incentive Rate at 9.00% ($/kWh)	83	0.4863108	0.4863108	0.5976226	0.6000636
VIR_950	Volumetric Incentive Rate at 9.50% ($/kWh)	83	0.5007553	0.5007553	0.6153732	0.6178868
VIR_1000	Volumetric Incentive Rate at 10.00% ($/kWh)	83	0.5153772	0.5153772	0.6333420	0.6359289

STAFF VIR RATES BY RATE CLASS AND PROJECT SIZE CATEGORY -- STEP2
ETO SOLAR PV DATA 2008-2009

PERIOD = 15, COUNTY CLASS = 3, TSRF = 0.90, DEGRADATION = 1.00
LOAN FEE = 0.00, INSURANCE = 0.0000, METER SERVICE = 0, TAX CALC = 0, TAX PREP = 0

The MEANS Procedure

Rate Class=1 Project Size Category=0 - 10 KW

Variable	Label	N	10th Pctl	25th Pctl	50th Pctl	Mean
System_Cost	System Cost ($)	242	16743.00	19898.00	24891.50	29057.92
DC_CAP	Capacity - DC (kW)	242	2.0000000	2.2400000	2.8650000	3.3067769
PUC_COST_WATT	System Cost per Watt ($/watt)	242	7.2372928	7.9226765	8.6877381	10.3946767
KWH_YEAR	Expected Annual Generation (kWh)	242	1980.00	2217.60	2836.35	3273.71
CF_YEAR	Annual Capacity Factor (%)	242	11.3013699	11.3013699	11.3013699	11.3013699
LPC_TSRF_DEG	County LPC x TSRF x Degradation	242	0.9900000	0.9900000	0.9900000	0.9900000
CMTR	Combined Marginal Tax Rate	0	.	.	.	.
VIR_600	Volumetric Incentive Rate at 6.00% ($/kWh)	242	0.5268891	0.5767863	0.6324843	0.7567528
VIR_650	Volumetric Incentive Rate at 6.50% ($/kWh)	242	0.5442367	0.5957769	0.6533087	0.7816686
VIR_700	Volumetric Incentive Rate at 7.00% ($/kWh)	242	0.5618496	0.6150577	0.6744514	0.8069654
VIR_750	Volumetric Incentive Rate at 7.50% ($/kWh)	242	0.5797222	0.6346229	0.6959059	0.8326353
VIR_800	Volumetric Incentive Rate at 8.00% ($/kWh)	242	0.5978492	0.6544665	0.7176658	0.8586704
VIR_850	Volumetric Incentive Rate at 8.50% ($/kWh)	242	0.6162249	0.6745825	0.7397242	0.8850629
VIR_900	Volumetric Incentive Rate at 9.00% ($/kWh)	242	0.6348438	0.6949645	0.7620745	0.9118044
VIR_950	Volumetric Incentive Rate at 9.50% ($/kWh)	242	0.6537000	0.7156064	0.7847097	0.9388870
VIR_1000	Volumetric Incentive Rate at 10.00% ($/kWh)	242	0.6727878	0.7365020	0.8076230	0.9663022

Rate Class=1 Project Size Category=10 - 100 KW

Variable	Label	N	10th Pctl	25th Pctl	50th Pctl	Mean
System_Cost	System Cost ($)	70	98901.25	125590.00	202575.00	253340.60
DC_CAP	Capacity - DC (kW)	70	12.1700000	15.3900000	29.7450000	32.9164286
PUC_COST_WATT	System Cost per Watt ($/watt)	70	6.1600000	6.1600000	7.6340321	7.7569232
KWH_YEAR	Expected Annual Generation (kWh)	70	12048.30	15236.10	29447.55	32587.26
CF_YEAR	Annual Capacity Factor (%)	70	11.3013699	11.3013699	11.3013699	11.3013699
LPC_TSRF_DEG	County LPC x TSRF x Degradation	70	0.9900000	0.9900000	0.9900000	0.9900000
CMTR	Combined Marginal Tax Rate	0	.	.	.	.
VIR_600	Volumetric Incentive Rate at 6.00% ($/kWh)	70	0.4484600	0.4484600	0.5557725	0.5647192
VIR_650	Volumetric Incentive Rate at 6.50% ($/kWh)	70	0.4632255	0.4632255	0.5740711	0.5833124
VIR_700	Volumetric Incentive Rate at 7.00% ($/kWh)	70	0.4782166	0.4782166	0.5926495	0.6021898
VIR_750	Volumetric Incentive Rate at 7.50% ($/kWh)	70	0.4934289	0.4934289	0.6115019	0.6213457
VIR_800	Volumetric Incentive Rate at 8.00% ($/kWh)	70	0.5088576	0.5088576	0.6306226	0.6407742
VIR_850	Volumetric Incentive Rate at 8.50% ($/kWh)	70	0.5244980	0.5244980	0.6500056	0.6604693
VIR_900	Volumetric Incentive Rate at 9.00% ($/kWh)	70	0.5403454	0.5403454	0.6696451	0.6804249
VIR_950	Volumetric Incentive Rate at 9.50% ($/kWh)	70	0.5563948	0.5563948	0.6895350	0.7006350
VIR_1000	Volumetric Incentive Rate at 10.00% ($/kWh)	70	0.5726413	0.5726413	0.7096692	0.7210933

STAFF VIR RATES BY RATE CLASS AND PROJECT SIZE CATEGORY -- STEP2
ETO SOLAR PV DATA 2008-2009

PERIOD = 15, COUNTY CLASS = 3, TSRF = 0.90, DEGRADATION = 1.00
LOAN FEE = 0.00, INSURANCE = 0.0000, METER SERVICE = 0, TAX CALC = 0, TAX PREP = 0

The MEANS Procedure

Rate Class=2 Project Size Category=0 - 10 KW

Variable	Label	N	10th Pctl	25th Pctl	50th Pctl	Mean
System_Cost	System Cost ($)	33	21600.00	25300.00	27720.00	30615.11
DC_CAP	Capacity - DC (kW)	33	2.3100000	3.1500000	3.8000000	3.8578788
PUC_COST_WATT	System Cost per Watt ($/watt)	33	7.0000000	7.3842807	7.9591837	8.0384119
KWH_YEAR	Expected Annual Generation (kWh)	33	2494.80	3402.00	4104.00	4166.51
CF_YEAR	Annual Capacity Factor (%)	33	12.3287671	12.3287671	12.3287671	12.3287671
LPC_TSRF_DEG	County LPC x TSRF x Degradation	33	1.0800000	1.0800000	1.0800000	1.0800000
CMTR	Combined Marginal Tax Rate	0	.	.	.	.
VIR_600	Volumetric Incentive Rate at 6.00% ($/kWh)	33	0.4671459	0.4927909	0.5311571	0.5364444
VIR_650	Volumetric Incentive Rate at 6.50% ($/kWh)	33	0.4825265	0.5090159	0.5486453	0.5541067
VIR_700	Volumetric Incentive Rate at 7.00% ($/kWh)	33	0.4981423	0.5254889	0.5664008	0.5720390
VIR_750	Volumetric Incentive Rate at 7.50% ($/kWh)	33	0.5139884	0.5422049	0.5844183	0.5902358
VIR_800	Volumetric Incentive Rate at 8.00% ($/kWh)	33	0.5300600	0.5591588	0.6026921	0.6086915
VIR_850	Volumetric Incentive Rate at 8.50% ($/kWh)	33	0.5463521	0.5763453	0.6212167	0.6274005
VIR_900	Volumetric Incentive Rate at 9.00% ($/kWh)	33	0.5628597	0.5937592	0.6399863	0.6463569
VIR_950	Volumetric Incentive Rate at 9.50% ($/kWh)	33	0.5795779	0.6113951	0.6589953	0.6655551
VIR_1000	Volumetric Incentive Rate at 10.00% ($/kWh)	33	0.5965014	0.6292477	0.6782377	0.6849891

Rate Class=2 Project Size Category=10 - 100 KW

Variable	Label	N	10th Pctl	25th Pctl	50th Pctl	Mean
System_Cost	System Cost ($)	3	67500.00	67500.00	95680.00	86941.67
DC_CAP	Capacity - DC (kW)	3	10.4600000	10.4600000	10.6600000	11.0266667
PUC_COST_WATT	System Cost per Watt ($/watt)	3	6.4531549	6.4531549	8.0000000	7.8710329
KWH_YEAR	Expected Annual Generation (kWh)	3	11296.80	11296.80	11512.80	11908.80
CF_YEAR	Annual Capacity Factor (%)	3	12.3287671	12.3287671	12.3287671	12.3287671
LPC_TSRF_DEG	County LPC x TSRF x Degradation	3	1.0800000	1.0800000	1.0800000	1.0800000
CMTR	Combined Marginal Tax Rate	0	.	.	.	.
VIR_600	Volumetric Incentive Rate at 6.00% ($/kWh)	3	0.4306521	0.4306521	0.5338810	0.5252744
VIR_650	Volumetric Incentive Rate at 6.50% ($/kWh)	3	0.4448312	0.4448312	0.5514589	0.5425689
VIR_700	Volumetric Incentive Rate at 7.00% ($/kWh)	3	0.4592270	0.4592270	0.5693055	0.5601277
VIR_750	Volumetric Incentive Rate at 7.50% ($/kWh)	3	0.4738352	0.4738352	0.5874153	0.5779456
VIR_800	Volumetric Incentive Rate at 8.00% ($/kWh)	3	0.4886513	0.4886513	0.6057828	0.5960171
VIR_850	Volumetric Incentive Rate at 8.50% ($/kWh)	3	0.5036707	0.5036707	0.6244024	0.6143365
VIR_900	Volumetric Incentive Rate at 9.00% ($/kWh)	3	0.5188887	0.5188887	0.6432683	0.6328982
VIR_950	Volumetric Incentive Rate at 9.50% ($/kWh)	3	0.5343008	0.5343008	0.6623747	0.6516966
VIR_1000	Volumetric Incentive Rate at 10.00% ($/kWh)	3	0.5499023	0.5499023	0.6817159	0.6707260

STAFF VIR RATES BY RATE CLASS AND PROJECT SIZE CATEGORY -- STEP2
ETO SOLAR PV DATA 2008-2009

PERIOD = 15, COUNTY CLASS = 3, TSRF = 0.90, DEGRADATION = 1.00
LOAN FEE = 0.00, INSURANCE = 0.0000, METER SERVICE = 0, TAX CALC = 0, TAX PREP = 0

The MEANS Procedure

Rate Class=3 Project Size Category=0 - 10 KW

Variable	Label	N	10th Pctl	25th Pctl	50th Pctl	Mean
System_Cost	System Cost ($)	92	17280.00	18488.78	25919.50	31496.76
DC_CAP	Capacity - DC (kW)	92	2.0400000	2.2800000	3.0900000	3.7725000
PUC_COST_WATT	System Cost per Watt ($/watt)	92	7.0635417	7.5603447	8.0000000	8.2972844
KWH_YEAR	Expected Annual Generation (kWh)	92	2386.80	2667.60	3615.30	4413.83
CF_YEAR	Annual Capacity Factor (%)	92	13.3561644	13.3561644	13.3561644	13.3561644
LPC_TSRF_DEG	County LPC x TSRF x Degradation	92	1.1700000	1.1700000	1.1700000	1.1700000
CMTR	Combined Marginal Tax Rate	0	.	.	.	.
VIR_600	Volumetric Incentive Rate at 6.00% ($/kWh)	92	0.4351258	0.4657297	0.4928132	0.5111264
VIR_650	Volumetric Incentive Rate at 6.50% ($/kWh)	92	0.4494522	0.4810638	0.5090390	0.5279551
VIR_700	Volumetric Incentive Rate at 7.00% ($/kWh)	92	0.4639976	0.4966322	0.5255127	0.5450411
VIR_750	Volumetric Incentive Rate at 7.50% ($/kWh)	92	0.4787576	0.5124302	0.5422295	0.5623791
VIR_800	Volumetric Incentive Rate at 8.00% ($/kWh)	92	0.4937276	0.5284531	0.5591841	0.5799637
VIR_850	Volumetric Incentive Rate at 8.50% ($/kWh)	92	0.5089030	0.5446958	0.5763714	0.5977897
VIR_900	Volumetric Incentive Rate at 9.00% ($/kWh)	92	0.5242791	0.5611535	0.5937861	0.6158515
VIR_950	Volumetric Incentive Rate at 9.50% ($/kWh)	92	0.5398513	0.5778209	0.6114228	0.6341436
VIR_1000	Volumetric Incentive Rate at 10.00% ($/kWh)	92	0.5556148	0.5946931	0.6292762	0.6526604

Rate Class=3 Project Size Category=10 - 100 KW

Variable	Label	N	10th Pctl	25th Pctl	50th Pctl	Mean
System_Cost	System Cost ($)	5	81300.00	154705.00	159600.00	190196.20
DC_CAP	Capacity - DC (kW)	5	10.8000000	17.5500000	22.8000000	26.0160000
PUC_COST_WATT	System Cost per Watt ($/watt)	5	6.8959341	6.9090909	7.4726316	7.5241068
KWH_YEAR	Expected Annual Generation (kWh)	5	12636.00	20533.50	26676.00	30438.72
CF_YEAR	Annual Capacity Factor (%)	5	13.3561644	13.3561644	13.3561644	13.3561644
LPC_TSRF_DEG	County LPC x TSRF x Degradation	5	1.1700000	1.1700000	1.1700000	1.1700000
CMTR	Combined Marginal Tax Rate	0	.	.	.	.
VIR_600	Volumetric Incentive Rate at 6.00% ($/kWh)	5	0.4248009	0.4256114	0.4603265	0.4634974
VIR_650	Volumetric Incentive Rate at 6.50% ($/kWh)	5	0.4387874	0.4396246	0.4754826	0.4787579
VIR_700	Volumetric Incentive Rate at 7.00% ($/kWh)	5	0.4529876	0.4538519	0.4908704	0.4942517
VIR_750	Volumetric Incentive Rate at 7.50% ($/kWh)	5	0.4673974	0.4682891	0.5064852	0.5099741
VIR_800	Volumetric Incentive Rate at 8.00% ($/kWh)	5	0.4820121	0.4829318	0.5223221	0.5259202
VIR_850	Volumetric Incentive Rate at 8.50% ($/kWh)	5	0.4968274	0.4977753	0.5383764	0.5420850
VIR_900	Volumetric Incentive Rate at 9.00% ($/kWh)	5	0.5118387	0.5128153	0.5546431	0.5584638
VIR_950	Volumetric Incentive Rate at 9.50% ($/kWh)	5	0.5270414	0.5280470	0.5711172	0.5750513
VIR_1000	Volumetric Incentive Rate at 10.00% ($/kWh)	5	0.5424309	0.5434658	0.5877936	0.5918427

STAFF VIR RATES BY RATE CLASS AND PROJECT SIZE CATEGORY -- STEP2
ETO SOLAR PV DATA 2008-2009

PERIOD = 15, COUNTY CLASS = 3, TSRF = 0.90, DEGRADATION = 1.00
LOAN FEE = 0.00, INSURANCE = 0.0000, METER SERVICE = 0, TAX CALC = 0, TAX PREP = 0

The MEANS Procedure

Rate Class=4 Project Size Category=0 - 10 KW

Variable	Label	N	10th Pctl	25th Pctl	50th Pctl	Mean
System_Cost	System Cost ($)	55	13700.00	14050.00	18000.00	24797.19
DC_CAP	Capacity - DC (kW)	55	2.0000000	2.0000000	2.1000000	3.1303636
PUC_COST_WATT	System Cost per Watt ($/watt)	55	6.5238095	6.9900000	7.5000000	7.8097056
KWH_YEAR	Expected Annual Generation (kWh)	55	2520.00	2520.00	2646.00	3944.26
CF_YEAR	Annual Capacity Factor (%)	55	14.3835616	14.3835616	14.3835616	14.3835616
LPC_TSRF_DEG	County LPC x TSRF x Degradation	55	1.2600000	1.2600000	1.2600000	1.2600000
CMTR	Combined Marginal Tax Rate	0	.	.	.	.
VIR_600	Volumetric Incentive Rate at 6.00% ($/kWh)	55	0.3731719	0.3998387	0.4290115	0.4467272
VIR_650	Volumetric Incentive Rate at 6.50% ($/kWh)	55	0.3854585	0.4130033	0.4431366	0.4614355
VIR_700	Volumetric Incentive Rate at 7.00% ($/kWh)	55	0.3979329	0.4263691	0.4574776	0.4763687
VIR_750	Volumetric Incentive Rate at 7.50% ($/kWh)	55	0.4105913	0.4399321	0.4720302	0.4915222
VIR_800	Volumetric Incentive Rate at 8.00% ($/kWh)	55	0.4234298	0.4536881	0.4867898	0.5068913
VIR_850	Volumetric Incentive Rate at 8.50% ($/kWh)	55	0.4364445	0.4676328	0.5017519	0.5224713
VIR_900	Volumetric Incentive Rate at 9.00% ($/kWh)	55	0.4496314	0.4817620	0.5169120	0.5382574
VIR_950	Volumetric Incentive Rate at 9.50% ($/kWh)	55	0.4629864	0.4960713	0.5322654	0.5542448
VIR_1000	Volumetric Incentive Rate at 10.00% ($/kWh)	55	0.4765055	0.5105565	0.5478074	0.5704286

Rate Class=4 Project Size Category=10 - 100 KW

Variable	Label	N	10th Pctl	25th Pctl	50th Pctl	Mean
System_Cost	System Cost ($)	5	148000.00	198000.00	304100.00	279820.00
DC_CAP	Capacity - DC (kW)	5	18.3600000	21.6000000	35.1000000	31.7880000
PUC_COST_WATT	System Cost per Watt ($/watt)	5	7.9038282	8.0610022	8.6638177	8.7590629
KWH_YEAR	Expected Annual Generation (kWh)	5	23133.60	27216.00	44226.00	40052.88
CF_YEAR	Annual Capacity Factor (%)	5	14.3835616	14.3835616	14.3835616	14.3835616
LPC_TSRF_DEG	County LPC x TSRF x Degradation	5	1.2600000	1.2600000	1.2600000	1.2600000
CMTR	Combined Marginal Tax Rate	0	.	.	.	.
VIR_600	Volumetric Incentive Rate at 6.00% ($/kWh)	5	0.4521111	0.4611017	0.4955837	0.5010319
VIR_650	Volumetric Incentive Rate at 6.50% ($/kWh)	5	0.4669967	0.4762833	0.5119006	0.5175282
VIR_700	Volumetric Incentive Rate at 7.00% ($/kWh)	5	0.4821099	0.4916971	0.5284670	0.5342767
VIR_750	Volumetric Incentive Rate at 7.50% ($/kWh)	5	0.4974460	0.5073381	0.5452778	0.5512722
VIR_800	Volumetric Incentive Rate at 8.00% ($/kWh)	5	0.5130004	0.5232018	0.5623277	0.5685096
VIR_850	Volumetric Incentive Rate at 8.50% ($/kWh)	5	0.5287681	0.5392831	0.5796116	0.5859836
VIR_900	Volumetric Incentive Rate at 9.00% ($/kWh)	5	0.5447445	0.5555772	0.5971242	0.6036886
VIR_950	Volumetric Incentive Rate at 9.50% ($/kWh)	5	0.5609246	0.5720790	0.6148600	0.6216195
VIR_1000	Volumetric Incentive Rate at 10.00% ($/kWh)	5	0.5773034	0.5887836	0.6328138	0.6397706

STAFF VIR RATES BY RATE CLASS AND PROJECT SIZE CATEGORY -- STEP2
ETO SOLAR PV DATA 2008-2009

PERIOD = 15, COUNTY CLASS = 3, TSRF = 0.90, DEGRADATION = 1.00
LOAN FEE = 0.00, INSURANCE = 0.0000, METER SERVICE = 0, TAX CALC = 0, TAX PREP = 0

The MEANS Procedure

Project Size Category=0 - 10 KW

Variable	Label	N	10th Pctl	25th Pctl	50th Pctl	Mean
System_Cost	System Cost ($)	422	15226.50	19350.00	24946.58	29156.07
DC_CAP	Capacity - DC (kW)	422	2.0000000	2.1600000	3.0000000	3.4284123
PUC_COST_WATT	System Cost per Watt ($/watt)	422	7.0000000	7.6463675	8.2871558	9.4162638
KWH_YEAR	Expected Annual Generation (kWh)	422	1999.80	2398.50	2970.00	3679.48
CF_YEAR	Annual Capacity Factor (%)	422	11.3013699	11.3013699	11.3013699	12.2313835
LPC_TSRF_DEG	County LPC x TSRF x Degradation	422	0.9900000	0.9900000	0.9900000	1.0714692
VIR_600	Volumetric Incentive Rate at 6.00% ($/kWh)	422	0.4367202	0.4928132	0.5697270	0.6455698
VIR_650	Volumetric Incentive Rate at 6.50% ($/kWh)	422	0.4510991	0.5090390	0.5884851	0.6668250
VIR_700	Volumetric Incentive Rate at 7.00% ($/kWh)	422	0.4656978	0.5255127	0.6075299	0.6884051
VIR_750	Volumetric Incentive Rate at 7.50% ($/kWh)	422	0.4805118	0.5422295	0.6268557	0.7103036
VIR_800	Volumetric Incentive Rate at 8.00% ($/kWh)	422	0.4955366	0.5591841	0.6464565	0.7325136
VIR_850	Volumetric Incentive Rate at 8.50% ($/kWh)	422	0.5107676	0.5763714	0.6663262	0.7550284
VIR_900	Volumetric Incentive Rate at 9.00% ($/kWh)	422	0.5262001	0.5937861	0.6864588	0.7778411
VIR_950	Volumetric Incentive Rate at 9.50% ($/kWh)	422	0.5418294	0.6114228	0.7068481	0.8009446
VIR_1000	Volumetric Incentive Rate at 10.00% ($/kWh)	422	0.5576506	0.6292762	0.7274878	0.8243320

Project Size Category=10 - 100 KW

Variable	Label	N	10th Pctl	25th Pctl	50th Pctl	Mean
System_Cost	System Cost ($)	83	95772.00	123996.00	193116.00	245117.44
DC_CAP	Capacity - DC (kW)	83	11.5500000	15.1200000	28.5000000	31.6415663
PUC_COST_WATT	System Cost per Watt ($/watt)	83	6.1600000	6.8959341	7.6869919	7.8073925
KWH_YEAR	Expected Annual Generation (kWh)	83	11979.00	14968.80	28215.00	32160.16
CF_YEAR	Annual Capacity Factor (%)	83	11.3013699	11.3013699	11.3013699	11.6479617
LPC_TSRF_DEG	County LPC x TSRF x Degradation	83	0.9900000	0.9900000	0.9900000	1.0203614
VIR_600	Volumetric Incentive Rate at 6.00% ($/kWh)	83	0.4484600	0.4484600	0.5511081	0.5533592
VIR_650	Volumetric Incentive Rate at 6.50% ($/kWh)	83	0.4632255	0.4632255	0.5692532	0.5715784
VIR_700	Volumetric Incentive Rate at 7.00% ($/kWh)	83	0.4782166	0.4782166	0.5876757	0.5900761
VIR_750	Volumetric Incentive Rate at 7.50% ($/kWh)	83	0.4934289	0.4934289	0.6063699	0.6088466
VIR_800	Volumetric Incentive Rate at 8.00% ($/kWh)	83	0.5088576	0.5088576	0.6253301	0.6278843
VIR_850	Volumetric Incentive Rate at 8.50% ($/kWh)	83	0.5244980	0.5244980	0.6445504	0.6471832
VIR_900	Volumetric Incentive Rate at 9.00% ($/kWh)	83	0.5403454	0.5403454	0.6640251	0.6667374
VIR_950	Volumetric Incentive Rate at 9.50% ($/kWh)	83	0.5563948	0.5563948	0.6837480	0.6865409
VIR_1000	Volumetric Incentive Rate at 10.00% ($/kWh)	83	0.5726413	0.5726413	0.7037133	0.7065877

STAFF VIR RATES BY RATE CLASS AND PROJECT SIZE CATEGORY -- STEP3
ETO SOLAR PV DATA 2008-2009

PERIOD = 15, COUNTY CLASS = 3, TSRF = 0.90, DEGRADATION = 0.94
LOAN FEE = 0.00, INSURANCE = 0.0000, METER SERVICE = 0, TAX CALC = 0, TAX PREP = 0

The MEANS Procedure

Rate Class=1 Project Size Category=0 - 10 KW

Variable	Label	N	10th Pctl	25th Pctl	50th Pctl	Mean
System_Cost	System Cost ($)	242	16743.00	19898.00	24891.50	29057.92
DC_CAP	Capacity - DC (kW)	242	2.0000000	2.2400000	2.8650000	3.3067769
PUC_COST_WATT	System Cost per Watt ($/watt)	242	7.2372928	7.9226765	8.6877381	10.3946767
KWH_YEAR	Expected Annual Generation (kWh)	242	1861.20	2084.54	2666.17	3077.29
CF_YEAR	Annual Capacity Factor (%)	242	10.6232877	10.6232877	10.6232877	10.6232877
LPC_TSRF_DEG	County LPC x TSRF x Degradation	242	0.9306000	0.9306000	0.9306000	0.9306000
CMTR	Combined Marginal Tax Rate	0	.	.	.	.
VIR_600	Volumetric Incentive Rate at 6.00% ($/kWh)	242	0.5605203	0.6136025	0.6728557	0.8050561
VIR_650	Volumetric Incentive Rate at 6.50% ($/kWh)	242	0.5789752	0.6338052	0.6950092	0.8315624
VIR_700	Volumetric Incentive Rate at 7.00% ($/kWh)	242	0.5977123	0.6543167	0.7175015	0.8584738
VIR_750	Volumetric Incentive Rate at 7.50% ($/kWh)	242	0.6167258	0.6751308	0.7403255	0.8857822
VIR_800	Volumetric Incentive Rate at 8.00% ($/kWh)	242	0.6360098	0.6962410	0.7634743	0.9134792
VIR_850	Volumetric Incentive Rate at 8.50% ($/kWh)	242	0.6555585	0.7176409	0.7869407	0.9415562
VIR_900	Volumetric Incentive Rate at 9.00% ($/kWh)	242	0.6753657	0.7393240	0.8107176	0.9700047
VIR_950	Volumetric Incentive Rate at 9.50% ($/kWh)	242	0.6954255	0.7612834	0.8347976	0.9988159
VIR_1000	Volumetric Incentive Rate at 10.00% ($/kWh)	242	0.7157317	0.7835127	0.8591735	1.0279811

Rate Class=1 Project Size Category=10 - 100 KW

Variable	Label	N	10th Pctl	25th Pctl	50th Pctl	Mean
System_Cost	System Cost ($)	70	98901.25	125590.00	202575.00	253340.60
DC_CAP	Capacity - DC (kW)	70	12.1700000	15.3900000	29.7450000	32.9164286
PUC_COST_WATT	System Cost per Watt ($/watt)	70	6.1600000	6.1600000	7.6340321	7.7569232
KWH_YEAR	Expected Annual Generation (kWh)	70	11325.40	14321.93	27680.70	30632.03
CF_YEAR	Annual Capacity Factor (%)	70	10.6232877	10.6232877	10.6232877	10.6232877
LPC_TSRF_DEG	County LPC x TSRF x Degradation	70	0.9306000	0.9306000	0.9306000	0.9306000
CMTR	Combined Marginal Tax Rate	0	.	.	.	.
VIR_600	Volumetric Incentive Rate at 6.00% ($/kWh)	70	0.4770851	0.4770851	0.5912473	0.6007651
VIR_650	Volumetric Incentive Rate at 6.50% ($/kWh)	70	0.4927930	0.4927930	0.6107139	0.6205451
VIR_700	Volumetric Incentive Rate at 7.00% ($/kWh)	70	0.5087411	0.5087411	0.6304782	0.6406275
VIR_750	Volumetric Incentive Rate at 7.50% ($/kWh)	70	0.5249243	0.5249243	0.6505339	0.6610061
VIR_800	Volumetric Incentive Rate at 8.00% ($/kWh)	70	0.5413378	0.5413378	0.6708751	0.6816747
VIR_850	Volumetric Incentive Rate at 8.50% ($/kWh)	70	0.5579766	0.5579766	0.6914953	0.7026269
VIR_900	Volumetric Incentive Rate at 9.00% ($/kWh)	70	0.5748355	0.5748355	0.7123884	0.7238563
VIR_950	Volumetric Incentive Rate at 9.50% ($/kWh)	70	0.5919093	0.5919093	0.7335479	0.7453564
VIR_1000	Volumetric Incentive Rate at 10.00% ($/kWh)	70	0.6091929	0.6091929	0.7549673	0.7671206

STAFF VIR RATES BY RATE CLASS AND PROJECT SIZE CATEGORY -- STEP3
ETO SOLAR PV DATA 2008-2009

PERIOD = 15, COUNTY CLASS = 3, TSRF = 0.90, DEGRADATION = 0.94
LOAN FEE = 0.00, INSURANCE = 0.0000, METER SERVICE = 0, TAX CALC = 0, TAX PREP = 0

The MEANS Procedure

Rate Class=2 Project Size Category=0 - 10 KW

Variable	Label	N	10th Pctl	25th Pctl	50th Pctl	Mean
System_Cost	System Cost ($)	33	21600.00	25300.00	27720.00	30615.11
DC_CAP	Capacity - DC (kW)	33	2.3100000	3.1500000	3.8000000	3.8578788
PUC_COST_WATT	System Cost per Watt ($/watt)	33	7.0000000	7.3842807	7.9591837	8.0384119
KWH_YEAR	Expected Annual Generation (kWh)	33	2345.11	3197.88	3857.76	3916.52
CF_YEAR	Annual Capacity Factor (%)	33	11.5890411	11.5890411	11.5890411	11.5890411
LPC_TSRF_DEG	County LPC x TSRF x Degradation	33	1.0152000	1.0152000	1.0152000	1.0152000
CMTR	Combined Marginal Tax Rate	0	.	.	.	.
VIR_600	Volumetric Incentive Rate at 6.00% ($/kWh)	33	0.4969637	0.5242456	0.5650608	0.5706856
VIR_650	Volumetric Incentive Rate at 6.50% ($/kWh)	33	0.5133261	0.5415063	0.5836652	0.5894752
VIR_700	Volumetric Incentive Rate at 7.00% ($/kWh)	33	0.5299386	0.5590308	0.6025541	0.6085521
VIR_750	Volumetric Incentive Rate at 7.50% ($/kWh)	33	0.5467962	0.5768138	0.6217216	0.6279104
VIR_800	Volumetric Incentive Rate at 8.00% ($/kWh)	33	0.5638936	0.5948498	0.6411618	0.6475441
VIR_850	Volumetric Incentive Rate at 8.50% ($/kWh)	33	0.5812256	0.6131333	0.6608688	0.6674473
VIR_900	Volumetric Incentive Rate at 9.00% ($/kWh)	33	0.5987870	0.6316587	0.6808365	0.6876138
VIR_950	Volumetric Incentive Rate at 9.50% ($/kWh)	33	0.6165722	0.6504203	0.7010588	0.7080373
VIR_1000	Volumetric Incentive Rate at 10.00% ($/kWh)	33	0.6345760	0.6694124	0.7215295	0.7287118

Rate Class=2 Project Size Category=10 - 100 KW

Variable	Label	N	10th Pctl	25th Pctl	50th Pctl	Mean
System_Cost	System Cost ($)	3	67500.00	67500.00	95680.00	86941.67
DC_CAP	Capacity - DC (kW)	3	10.4600000	10.4600000	10.6600000	11.0266667
PUC_COST_WATT	System Cost per Watt ($/watt)	3	6.4531549	6.4531549	8.0000000	7.8710329
KWH_YEAR	Expected Annual Generation (kWh)	3	10618.99	10618.99	10822.03	11194.27
CF_YEAR	Annual Capacity Factor (%)	3	11.5890411	11.5890411	11.5890411	11.5890411
LPC_TSRF_DEG	County LPC x TSRF x Degradation	3	1.0152000	1.0152000	1.0152000	1.0152000
CMTR	Combined Marginal Tax Rate	0	.	.	.	.
VIR_600	Volumetric Incentive Rate at 6.00% ($/kWh)	3	0.4581405	0.4581405	0.5679585	0.5588025
VIR_650	Volumetric Incentive Rate at 6.50% ($/kWh)	3	0.4732247	0.4732247	0.5866584	0.5772009
VIR_700	Volumetric Incentive Rate at 7.00% ($/kWh)	3	0.4885394	0.4885394	0.6056441	0.5958806
VIR_750	Volumetric Incentive Rate at 7.50% ($/kWh)	3	0.5040800	0.5040800	0.6249099	0.6148358
VIR_800	Volumetric Incentive Rate at 8.00% ($/kWh)	3	0.5198418	0.5198418	0.6444498	0.6340607
VIR_850	Volumetric Incentive Rate at 8.50% ($/kWh)	3	0.5358199	0.5358199	0.6642579	0.6535494
VIR_900	Volumetric Incentive Rate at 9.00% ($/kWh)	3	0.5520093	0.5520093	0.6843280	0.6732960
VIR_950	Volumetric Incentive Rate at 9.50% ($/kWh)	3	0.5684051	0.5684051	0.7046540	0.6932943
VIR_1000	Volumetric Incentive Rate at 10.00% ($/kWh)	3	0.5850024	0.5850024	0.7252297	0.7135383

STAFF VIR RATES BY RATE CLASS AND PROJECT SIZE CATEGORY -- STEP3
ETO SOLAR PV DATA 2008-2009

PERIOD = 15, COUNTY CLASS = 3, TSRF = 0.90, DEGRADATION = 0.94
LOAN FEE = 0.00, INSURANCE = 0.0000, METER SERVICE = 0, TAX CALC = 0, TAX PREP = 0

The MEANS Procedure

Rate Class=3 Project Size Category=0 - 10 KW

Variable	Label	N	10th Pctl	25th Pctl	50th Pctl	Mean
System_Cost	System Cost ($)	92	17280.00	18488.78	25919.50	31496.76
DC_CAP	Capacity - DC (kW)	92	2.0400000	2.2800000	3.0900000	3.7725000
PUC_COST_WATT	System Cost per Watt ($/watt)	92	7.0635417	7.5603447	8.0000000	8.2972844
KWH_YEAR	Expected Annual Generation (kWh)	92	2243.59	2507.54	3398.38	4149.00
CF_YEAR	Annual Capacity Factor (%)	92	12.5547945	12.5547945	12.5547945	12.5547945
LPC_TSRF_DEG	County LPC x TSRF x Degradation	92	1.0998000	1.0998000	1.0998000	1.0998000
CMTR	Combined Marginal Tax Rate	0	.	.	.	.
VIR_600	Volumetric Incentive Rate at 6.00% ($/kWh)	92	0.4628998	0.4954572	0.5242694	0.5437515
VIR_650	Volumetric Incentive Rate at 6.50% ($/kWh)	92	0.4781407	0.5117699	0.5415308	0.5616544
VIR_700	Volumetric Incentive Rate at 7.00% ($/kWh)	92	0.4936145	0.5283321	0.5590561	0.5798309
VIR_750	Volumetric Incentive Rate at 7.50% ($/kWh)	92	0.5093166	0.5451386	0.5768399	0.5982756
VIR_800	Volumetric Incentive Rate at 8.00% ($/kWh)	92	0.5252421	0.5621842	0.5948768	0.6169827
VIR_850	Volumetric Incentive Rate at 8.50% ($/kWh)	92	0.5413861	0.5794637	0.6131611	0.6359465
VIR_900	Volumetric Incentive Rate at 9.00% ($/kWh)	92	0.5577437	0.5969718	0.6316873	0.6551612
VIR_950	Volumetric Incentive Rate at 9.50% ($/kWh)	92	0.5743099	0.6147031	0.6504498	0.6746209
VIR_1000	Volumetric Incentive Rate at 10.00% ($/kWh)	92	0.5910796	0.6326523	0.6694428	0.6943196

Rate Class=3 Project Size Category=10 - 100 KW

Variable	Label	N	10th Pctl	25th Pctl	50th Pctl	Mean
System_Cost	System Cost ($)	5	81300.00	154705.00	159600.00	190196.20
DC_CAP	Capacity - DC (kW)	5	10.8000000	17.5500000	22.8000000	26.0160000
PUC_COST_WATT	System Cost per Watt ($/watt)	5	6.8959341	6.9090909	7.4726316	7.5241068
KWH_YEAR	Expected Annual Generation (kWh)	5	11877.84	19301.49	25075.44	28612.40
CF_YEAR	Annual Capacity Factor (%)	5	12.5547945	12.5547945	12.5547945	12.5547945
LPC_TSRF_DEG	County LPC x TSRF x Degradation	5	1.0998000	1.0998000	1.0998000	1.0998000
CMTR	Combined Marginal Tax Rate	0	.	.	.	.
VIR_600	Volumetric Incentive Rate at 6.00% ($/kWh)	5	0.4519159	0.4527781	0.4897090	0.4930824
VIR_650	Volumetric Incentive Rate at 6.50% ($/kWh)	5	0.4667951	0.4676857	0.5058325	0.5093170
VIR_700	Volumetric Incentive Rate at 7.00% ($/kWh)	5	0.4819018	0.4828212	0.5222025	0.5257997
VIR_750	Volumetric Incentive Rate at 7.50% ($/kWh)	5	0.4972312	0.4981799	0.5388140	0.5425256
VIR_800	Volumetric Incentive Rate at 8.00% ($/kWh)	5	0.5127789	0.5137572	0.5556619	0.5594895
VIR_850	Volumetric Incentive Rate at 8.50% ($/kWh)	5	0.5285398	0.5295482	0.5727409	0.5766862
VIR_900	Volumetric Incentive Rate at 9.00% ($/kWh)	5	0.5445093	0.5455482	0.5900459	0.5941104
VIR_950	Volumetric Incentive Rate at 9.50% ($/kWh)	5	0.5606824	0.5617521	0.6075715	0.6117567
VIR_1000	Volumetric Incentive Rate at 10.00% ($/kWh)	5	0.5770541	0.5781551	0.6253124	0.6296199

STAFF VIR RATES BY RATE CLASS AND PROJECT SIZE CATEGORY -- STEP3
ETO SOLAR PV DATA 2008-2009

PERIOD = 15, COUNTY CLASS = 3, TSRF = 0.90, DEGRADATION = 0.94
LOAN FEE = 0.00, INSURANCE = 0.0000, METER SERVICE = 0, TAX CALC = 0, TAX PREP = 0

The MEANS Procedure

Rate Class=4 Project Size Category=0 - 10 KW

Variable	Label	N	10th Pctl	25th Pctl	50th Pctl	Mean
System_Cost	System Cost ($)	55	13700.00	14050.00	18000.00	24797.19
DC_CAP	Capacity - DC (kW)	55	2.0000000	2.0000000	2.1000000	3.1303636
PUC_COST_WATT	System Cost per Watt ($/watt)	55	6.5238095	6.9900000	7.5000000	7.8097056
KWH_YEAR	Expected Annual Generation (kWh)	55	2368.80	2368.80	2487.24	3707.60
CF_YEAR	Annual Capacity Factor (%)	55	13.5205479	13.5205479	13.5205479	13.5205479
LPC_TSRF_DEG	County LPC x TSRF x Degradation	55	1.1844000	1.1844000	1.1844000	1.1844000
CMTR	Combined Marginal Tax Rate	0	.	.	.	.
VIR_600	Volumetric Incentive Rate at 6.00% ($/kWh)	55	0.3969914	0.4253604	0.4563952	0.4752416
VIR_650	Volumetric Incentive Rate at 6.50% ($/kWh)	55	0.4100622	0.4393652	0.4714219	0.4908888
VIR_700	Volumetric Incentive Rate at 7.00% ($/kWh)	55	0.4233329	0.4535842	0.4866783	0.5067752
VIR_750	Volumetric Incentive Rate at 7.50% ($/kWh)	55	0.4367993	0.4680129	0.5021597	0.5228960
VIR_800	Volumetric Incentive Rate at 8.00% ($/kWh)	55	0.4504573	0.4826469	0.5178615	0.5392461
VIR_850	Volumetric Incentive Rate at 8.50% ($/kWh)	55	0.4643027	0.4974817	0.5337786	0.5558205
VIR_900	Volumetric Incentive Rate at 9.00% ($/kWh)	55	0.4783313	0.5125128	0.5499064	0.5726143
VIR_950	Volumetric Incentive Rate at 9.50% ($/kWh)	55	0.4925387	0.5277355	0.5662398	0.5896221
VIR_1000	Volumetric Incentive Rate at 10.00% ($/kWh)	55	0.5069207	0.5431452	0.5827738	0.6068389

Rate Class=4 Project Size Category=10 - 100 KW

Variable	Label	N	10th Pctl	25th Pctl	50th Pctl	Mean
System_Cost	System Cost ($)	5	148000.00	198000.00	304100.00	279820.00
DC_CAP	Capacity - DC (kW)	5	18.3600000	21.6000000	35.1000000	31.7880000
PUC_COST_WATT	System Cost per Watt ($/watt)	5	7.9038282	8.0610022	8.6638177	8.7590629
KWH_YEAR	Expected Annual Generation (kWh)	5	21745.58	25583.04	41572.44	37649.71
CF_YEAR	Annual Capacity Factor (%)	5	13.5205479	13.5205479	13.5205479	13.5205479
LPC_TSRF_DEG	County LPC x TSRF x Degradation	5	1.1844000	1.1844000	1.1844000	1.1844000
CMTR	Combined Marginal Tax Rate	0	.	.	.	.
VIR_600	Volumetric Incentive Rate at 6.00% ($/kWh)	5	0.4809693	0.4905337	0.5272167	0.5330126
VIR_650	Volumetric Incentive Rate at 6.50% ($/kWh)	5	0.4968050	0.5066844	0.5445751	0.5505619
VIR_700	Volumetric Incentive Rate at 7.00% ($/kWh)	5	0.5128829	0.5230820	0.5621989	0.5683794
VIR_750	Volumetric Incentive Rate at 7.50% ($/kWh)	5	0.5291979	0.5397214	0.5800827	0.5864598
VIR_800	Volumetric Incentive Rate at 8.00% ($/kWh)	5	0.5457451	0.5565976	0.5982210	0.6047975
VIR_850	Volumetric Incentive Rate at 8.50% ($/kWh)	5	0.5625193	0.5737054	0.6166081	0.6233868
VIR_900	Volumetric Incentive Rate at 9.00% ($/kWh)	5	0.5795154	0.5910396	0.6352385	0.6422220
VIR_950	Volumetric Incentive Rate at 9.50% ($/kWh)	5	0.5967283	0.6085947	0.6541064	0.6612973
VIR_1000	Volumetric Incentive Rate at 10.00% ($/kWh)	5	0.6141526	0.6263655	0.6732062	0.6806070

STAFF VIR RATES BY RATE CLASS AND PROJECT SIZE CATEGORY -- STEP3
ETO SOLAR PV DATA 2008-2009

PERIOD = 15, COUNTY CLASS = 3, TSRF = 0.90, DEGRADATION = 0.94
LOAN FEE = 0.00, INSURANCE = 0.0000, METER SERVICE = 0, TAX CALC = 0, TAX PREP = 0

The MEANS Procedure

Project Size Category=0 - 10 KW

Variable	Label	N	10th Pctl	25th Pctl	50th Pctl	Mean
System_Cost	System Cost ($)	422	15226.50	19350.00	24946.58	29156.07
DC_CAP	Capacity - DC (kW)	422	2.0000000	2.1600000	3.0000000	3.4284123
PUC_COST_WATT	System Cost per Watt ($/watt)	422	7.0000000	7.6463675	8.2871558	9.4162638
KWH_YEAR	Expected Annual Generation (kWh)	422	1879.81	2254.59	2791.80	3458.71
CF_YEAR	Annual Capacity Factor (%)	422	10.6232877	10.6232877	10.6232877	11.4975005
LPC_TSRF_DEG	County LPC x TSRF x Degradation	422	0.9306000	0.9306000	0.9306000	1.0071810
VIR_600	Volumetric Incentive Rate at 6.00% ($/kWh)	422	0.4645959	0.5242694	0.6060925	0.6867764
VIR_650	Volumetric Incentive Rate at 6.50% ($/kWh)	422	0.4798926	0.5415308	0.6260479	0.7093883
VIR_700	Volumetric Incentive Rate at 7.00% ($/kWh)	422	0.4954232	0.5590561	0.6463084	0.7323459
VIR_750	Volumetric Incentive Rate at 7.50% ($/kWh)	422	0.5111828	0.5768399	0.6668678	0.7556421
VIR_800	Volumetric Incentive Rate at 8.00% ($/kWh)	422	0.5271666	0.5948768	0.6877196	0.7792698
VIR_850	Volumetric Incentive Rate at 8.50% ($/kWh)	422	0.5433698	0.6131611	0.7088576	0.8032218
VIR_900	Volumetric Incentive Rate at 9.00% ($/kWh)	422	0.5597874	0.6316873	0.7302753	0.8274905
VIR_950	Volumetric Incentive Rate at 9.50% ($/kWh)	422	0.5764142	0.6504498	0.7519660	0.8520688
VIR_1000	Volumetric Incentive Rate at 10.00% ($/kWh)	422	0.5932454	0.6694428	0.7739232	0.8769490

Project Size Category=10 - 100 KW

Variable	Label	N	10th Pctl	25th Pctl	50th Pctl	Mean
System_Cost	System Cost ($)	83	95772.00	123996.00	193116.00	245117.44
DC_CAP	Capacity - DC (kW)	83	11.5500000	15.1200000	28.5000000	31.6415663
PUC_COST_WATT	System Cost per Watt ($/watt)	83	6.1600000	6.8959341	7.6869919	7.8073925
KWH_YEAR	Expected Annual Generation (kWh)	83	11260.26	14070.67	26522.10	30230.55
CF_YEAR	Annual Capacity Factor (%)	83	10.6232877	10.6232877	10.6232877	10.9490840
LPC_TSRF_DEG	County LPC x TSRF x Degradation	83	0.9306000	0.9306000	0.9306000	0.9591398
VIR_600	Volumetric Incentive Rate at 6.00% ($/kWh)	83	0.4770851	0.4770851	0.5862852	0.5886800
VIR_650	Volumetric Incentive Rate at 6.50% ($/kWh)	83	0.4927930	0.4927930	0.6055885	0.6080621
VIR_700	Volumetric Incentive Rate at 7.00% ($/kWh)	83	0.5087411	0.5087411	0.6251869	0.6277405
VIR_750	Volumetric Incentive Rate at 7.50% ($/kWh)	83	0.5249243	0.5249243	0.6450743	0.6477092
VIR_800	Volumetric Incentive Rate at 8.00% ($/kWh)	83	0.5413378	0.5413378	0.6652447	0.6679620
VIR_850	Volumetric Incentive Rate at 8.50% ($/kWh)	83	0.5579766	0.5579766	0.6856920	0.6884927
VIR_900	Volumetric Incentive Rate at 9.00% ($/kWh)	83	0.5748355	0.5748355	0.7064097	0.7092951
VIR_950	Volumetric Incentive Rate at 9.50% ($/kWh)	83	0.5919093	0.5919093	0.7273915	0.7303626
VIR_1000	Volumetric Incentive Rate at 10.00% ($/kWh)	83	0.6091929	0.6091929	0.7486312	0.7516890

STAFF VIR RATES BY RATE CLASS AND PROJECT SIZE CATEGORY -- STEP4
ETO SOLAR PV DATA 2008-2009

PERIOD = 15, COUNTY CLASS = 3, TSRF = 0.90, DEGRADATION = 0.94
LOAN FEE = 0.00, INSURANCE = 0.0022, METER SERVICE = 0, TAX CALC = 0, TAX PREP = 0

The MEANS Procedure

Rate Class=1 Project Size Category=0 - 10 KW

Variable	Label	N	10th Pctl	25th Pctl	50th Pctl	Mean
System_Cost	System Cost ($)	242	16743.00	19898.00	24891.50	29057.92
DC_CAP	Capacity - DC (kW)	242	2.0000000	2.2400000	2.8650000	3.3067769
PUC_COST_WATT	System Cost per Watt ($/watt)	242	7.2372928	7.9226765	8.6877381	10.3946767
KWH_YEAR	Expected Annual Generation (kWh)	242	1861.20	2084.54	2666.17	3077.29
CF_YEAR	Annual Capacity Factor (%)	242	10.6232877	10.6232877	10.6232877	10.6232877
LPC_TSRF_DEG	County LPC x TSRF x Degradation	242	0.9306000	0.9306000	0.9306000	0.9306000
CMTR	Combined Marginal Tax Rate	0	.	.	.	.
VIR_600	Volumetric Incentive Rate at 6.00% ($/kWh)	242	0.5776297	0.6323322	0.6933940	0.8296299
VIR_650	Volumetric Incentive Rate at 6.50% ($/kWh)	242	0.5960847	0.6525349	0.7155476	0.8561361
VIR_700	Volumetric Incentive Rate at 7.00% ($/kWh)	242	0.6148218	0.6730464	0.7380398	0.8830475
VIR_750	Volumetric Incentive Rate at 7.50% ($/kWh)	242	0.6338352	0.6938605	0.7608639	0.9103559
VIR_800	Volumetric Incentive Rate at 8.00% ($/kWh)	242	0.6531193	0.7149707	0.7840126	0.9380529
VIR_850	Volumetric Incentive Rate at 8.50% ($/kWh)	242	0.6726679	0.7363707	0.8074791	0.9661299
VIR_900	Volumetric Incentive Rate at 9.00% ($/kWh)	242	0.6924751	0.7580537	0.8312559	0.9945784
VIR_950	Volumetric Incentive Rate at 9.50% ($/kWh)	242	0.7125349	0.7800132	0.8553360	1.0233896
VIR_1000	Volumetric Incentive Rate at 10.00% ($/kWh)	242	0.7328412	0.8022425	0.8797118	1.0525548

Rate Class=1 Project Size Category=10 - 100 KW

Variable	Label	N	10th Pctl	25th Pctl	50th Pctl	Mean
System_Cost	System Cost ($)	70	98901.25	125590.00	202575.00	253340.60
DC_CAP	Capacity - DC (kW)	70	12.1700000	15.3900000	29.7450000	32.9164286
PUC_COST_WATT	System Cost per Watt ($/watt)	70	6.1600000	6.1600000	7.6340321	7.7569232
KWH_YEAR	Expected Annual Generation (kWh)	70	11325.40	14321.93	27680.70	30632.03
CF_YEAR	Annual Capacity Factor (%)	70	10.6232877	10.6232877	10.6232877	10.6232877
LPC_TSRF_DEG	County LPC x TSRF x Degradation	70	0.9306000	0.9306000	0.9306000	0.9306000
CMTR	Combined Marginal Tax Rate	0	.	.	.	.
VIR_600	Volumetric Incentive Rate at 6.00% ($/kWh)	70	0.4916478	0.4916478	0.6092947	0.6191030
VIR_650	Volumetric Incentive Rate at 6.50% ($/kWh)	70	0.5073557	0.5073557	0.6287613	0.6388830
VIR_700	Volumetric Incentive Rate at 7.00% ($/kWh)	70	0.5233037	0.5233037	0.6485255	0.6589654
VIR_750	Volumetric Incentive Rate at 7.50% ($/kWh)	70	0.5394870	0.5394870	0.6685813	0.6793440
VIR_800	Volumetric Incentive Rate at 8.00% ($/kWh)	70	0.5559005	0.5559005	0.6889224	0.7000126
VIR_850	Volumetric Incentive Rate at 8.50% ($/kWh)	70	0.5725393	0.5725393	0.7095427	0.7209648
VIR_900	Volumetric Incentive Rate at 9.00% ($/kWh)	70	0.5893981	0.5893981	0.7304358	0.7421942
VIR_950	Volumetric Incentive Rate at 9.50% ($/kWh)	70	0.6064720	0.6064720	0.7515952	0.7636942
VIR_1000	Volumetric Incentive Rate at 10.00% ($/kWh)	70	0.6237556	0.6237556	0.7730146	0.7854584

STAFF VIR RATES BY RATE CLASS AND PROJECT SIZE CATEGORY -- STEP4
ETO SOLAR PV DATA 2008-2009

PERIOD = 15, COUNTY CLASS = 3, TSRF = 0.90, DEGRADATION = 0.94
LOAN FEE = 0.00, INSURANCE = 0.0022, METER SERVICE = 0, TAX CALC = 0, TAX PREP = 0

The MEANS Procedure

Rate Class=2 Project Size Category=0 - 10 KW

Variable	Label	N	10th Pctl	25th Pctl	50th Pctl	Mean
System_Cost	System Cost ($)	33	21600.00	25300.00	27720.00	30615.11
DC_CAP	Capacity - DC (kW)	33	2.3100000	3.1500000	3.8000000	3.8578788
PUC_COST_WATT	System Cost per Watt ($/watt)	33	7.0000000	7.3842807	7.9591837	8.0384119
KWH_YEAR	Expected Annual Generation (kWh)	33	2345.11	3197.88	3857.76	3916.52
CF_YEAR	Annual Capacity Factor (%)	33	11.5890411	11.5890411	11.5890411	11.5890411
LPC_TSRF_DEG	County LPC x TSRF x Degradation	33	1.0152000	1.0152000	1.0152000	1.0152000
CMTR	Combined Marginal Tax Rate	0	.	.	.	.
VIR_600	Volumetric Incentive Rate at 6.00% ($/kWh)	33	0.5121331	0.5402478	0.5823088	0.5881053
VIR_650	Volumetric Incentive Rate at 6.50% ($/kWh)	33	0.5284955	0.5575085	0.6009133	0.6068949
VIR_700	Volumetric Incentive Rate at 7.00% ($/kWh)	33	0.5451080	0.5750329	0.6198021	0.6259718
VIR_750	Volumetric Incentive Rate at 7.50% ($/kWh)	33	0.5619656	0.5928159	0.6389696	0.6453301
VIR_800	Volumetric Incentive Rate at 8.00% ($/kWh)	33	0.5790630	0.6108520	0.6584098	0.6649639
VIR_850	Volumetric Incentive Rate at 8.50% ($/kWh)	33	0.5963951	0.6291355	0.6781168	0.6848670
VIR_900	Volumetric Incentive Rate at 9.00% ($/kWh)	33	0.6139564	0.6476609	0.6980845	0.7050335
VIR_950	Volumetric Incentive Rate at 9.50% ($/kWh)	33	0.6317416	0.6664225	0.7183068	0.7254571
VIR_1000	Volumetric Incentive Rate at 10.00% ($/kWh)	33	0.6497454	0.6854146	0.7387775	0.7461316

Rate Class=2 Project Size Category=10 - 100 KW

Variable	Label	N	10th Pctl	25th Pctl	50th Pctl	Mean
System_Cost	System Cost ($)	3	67500.00	67500.00	95680.00	86941.67
DC_CAP	Capacity - DC (kW)	3	10.4600000	10.4600000	10.6600000	11.0266667
PUC_COST_WATT	System Cost per Watt ($/watt)	3	6.4531549	6.4531549	8.0000000	7.8710329
KWH_YEAR	Expected Annual Generation (kWh)	3	10618.99	10618.99	10822.03	11194.27
CF_YEAR	Annual Capacity Factor (%)	3	11.5890411	11.5890411	11.5890411	11.5890411
LPC_TSRF_DEG	County LPC x TSRF x Degradation	3	1.0152000	1.0152000	1.0152000	1.0152000
CMTR	Combined Marginal Tax Rate	0	.	.	.	.
VIR_600	Volumetric Incentive Rate at 6.00% ($/kWh)	3	0.4721249	0.4721249	0.5852950	0.5758595
VIR_650	Volumetric Incentive Rate at 6.50% ($/kWh)	3	0.4872090	0.4872090	0.6039949	0.5942579
VIR_700	Volumetric Incentive Rate at 7.00% ($/kWh)	3	0.5025238	0.5025238	0.6229806	0.6129376
VIR_750	Volumetric Incentive Rate at 7.50% ($/kWh)	3	0.5180644	0.5180644	0.6422464	0.6318928
VIR_800	Volumetric Incentive Rate at 8.00% ($/kWh)	3	0.5338262	0.5338262	0.6617863	0.6511177
VIR_850	Volumetric Incentive Rate at 8.50% ($/kWh)	3	0.5498042	0.5498042	0.6815943	0.6706064
VIR_900	Volumetric Incentive Rate at 9.00% ($/kWh)	3	0.5659937	0.5659937	0.7016644	0.6903530
VIR_950	Volumetric Incentive Rate at 9.50% ($/kWh)	3	0.5823895	0.5823895	0.7219904	0.7103513
VIR_1000	Volumetric Incentive Rate at 10.00% ($/kWh)	3	0.5989868	0.5989868	0.7425661	0.7305953

STAFF VIR RATES BY RATE CLASS AND PROJECT SIZE CATEGORY -- STEP4
ETO SOLAR PV DATA 2008-2009

PERIOD = 15, COUNTY CLASS = 3, TSRF = 0.90, DEGRADATION = 0.94
LOAN FEE = 0.00, INSURANCE = 0.0022, METER SERVICE = 0, TAX CALC = 0, TAX PREP = 0

The MEANS Procedure

Rate Class=3 Project Size Category=0 - 10 KW

Variable	Label	N	10th Pctl	25th Pctl	50th Pctl	Mean
System_Cost	System Cost ($)	92	17280.00	18488.78	25919.50	31496.76
DC_CAP	Capacity - DC (kW)	92	2.0400000	2.2800000	3.0900000	3.7725000
PUC_COST_WATT	System Cost per Watt ($/watt)	92	7.0635417	7.5603447	8.0000000	8.2972844
KWH_YEAR	Expected Annual Generation (kWh)	92	2243.59	2507.54	3398.38	4149.00
CF_YEAR	Annual Capacity Factor (%)	92	12.5547945	12.5547945	12.5547945	12.5547945
LPC_TSRF_DEG	County LPC x TSRF x Degradation	92	1.0998000	1.0998000	1.0998000	1.0998000
CMTR	Combined Marginal Tax Rate	0	.	.	.	.
VIR_600	Volumetric Incentive Rate at 6.00% ($/kWh)	92	0.4770295	0.5105806	0.5402723	0.5603491
VIR_650	Volumetric Incentive Rate at 6.50% ($/kWh)	92	0.4922703	0.5268934	0.5575337	0.5782520
VIR_700	Volumetric Incentive Rate at 7.00% ($/kWh)	92	0.5077442	0.5434555	0.5750590	0.5964285
VIR_750	Volumetric Incentive Rate at 7.50% ($/kWh)	92	0.5234462	0.5602620	0.5928428	0.6148732
VIR_800	Volumetric Incentive Rate at 8.00% ($/kWh)	92	0.5393717	0.5773076	0.6108797	0.6335803
VIR_850	Volumetric Incentive Rate at 8.50% ($/kWh)	92	0.5555158	0.5945871	0.6291640	0.6525441
VIR_900	Volumetric Incentive Rate at 9.00% ($/kWh)	92	0.5718734	0.6120952	0.6476903	0.6717588
VIR_950	Volumetric Incentive Rate at 9.50% ($/kWh)	92	0.5884396	0.6298265	0.6664527	0.6912185
VIR_1000	Volumetric Incentive Rate at 10.00% ($/kWh)	92	0.6052093	0.6477757	0.6854457	0.7109172

Rate Class=3 Project Size Category=10 - 100 KW

Variable	Label	N	10th Pctl	25th Pctl	50th Pctl	Mean
System_Cost	System Cost ($)	5	81300.00	154705.00	159600.00	190196.20
DC_CAP	Capacity - DC (kW)	5	10.8000000	17.5500000	22.8000000	26.0160000
PUC_COST_WATT	System Cost per Watt ($/watt)	5	6.8959341	6.9090909	7.4726316	7.5241068
KWH_YEAR	Expected Annual Generation (kWh)	5	11877.84	19301.49	25075.44	28612.40
CF_YEAR	Annual Capacity Factor (%)	5	12.5547945	12.5547945	12.5547945	12.5547945
LPC_TSRF_DEG	County LPC x TSRF x Degradation	5	1.0998000	1.0998000	1.0998000	1.0998000
CMTR	Combined Marginal Tax Rate	0	.	.	.	.
VIR_600	Volumetric Incentive Rate at 6.00% ($/kWh)	5	0.4657103	0.4665988	0.5046570	0.5081333
VIR_650	Volumetric Incentive Rate at 6.50% ($/kWh)	5	0.4805895	0.4815064	0.5207805	0.5243679
VIR_700	Volumetric Incentive Rate at 7.00% ($/kWh)	5	0.4956961	0.4966419	0.5371505	0.5408507
VIR_750	Volumetric Incentive Rate at 7.50% ($/kWh)	5	0.5110256	0.5120006	0.5537620	0.5575766
VIR_800	Volumetric Incentive Rate at 8.00% ($/kWh)	5	0.5265732	0.5275779	0.5706098	0.5745405
VIR_850	Volumetric Incentive Rate at 8.50% ($/kWh)	5	0.5423342	0.5433689	0.5876889	0.5917372
VIR_900	Volumetric Incentive Rate at 9.00% ($/kWh)	5	0.5583037	0.5593689	0.6049938	0.6091613
VIR_950	Volumetric Incentive Rate at 9.50% ($/kWh)	5	0.5744767	0.5755728	0.6225194	0.6268077
VIR_1000	Volumetric Incentive Rate at 10.00% ($/kWh)	5	0.5908485	0.5919758	0.6402604	0.6446708

STAFF VIR RATES BY RATE CLASS AND PROJECT SIZE CATEGORY -- STEP4
ETO SOLAR PV DATA 2008-2009

PERIOD = 15, COUNTY CLASS = 3, TSRF = 0.90, DEGRADATION = 0.94
LOAN FEE = 0.00, INSURANCE = 0.0022, METER SERVICE = 0, TAX CALC = 0, TAX PREP = 0

The MEANS Procedure

Rate Class=4 Project Size Category=0 - 10 KW

Variable	Label	N	10th Pctl	25th Pctl	50th Pctl	Mean
System_Cost	System Cost ($)	55	13700.00	14050.00	18000.00	24797.19
DC_CAP	Capacity - DC (kW)	55	2.0000000	2.0000000	2.1000000	3.1303636
PUC_COST_WATT	System Cost per Watt ($/watt)	55	6.5238095	6.9900000	7.5000000	7.8097056
KWH_YEAR	Expected Annual Generation (kWh)	55	2368.80	2368.80	2487.24	3707.60
CF_YEAR	Annual Capacity Factor (%)	55	13.5205479	13.5205479	13.5205479	13.5205479
LPC_TSRF_DEG	County LPC x TSRF x Degradation	55	1.1844000	1.1844000	1.1844000	1.1844000
CMTR	Combined Marginal Tax Rate	0	.	.	.	.
VIR_600	Volumetric Incentive Rate at 6.00% ($/kWh)	55	0.4091093	0.4383441	0.4703263	0.4897480
VIR_650	Volumetric Incentive Rate at 6.50% ($/kWh)	55	0.4221801	0.4523490	0.4853530	0.5053952
VIR_700	Volumetric Incentive Rate at 7.00% ($/kWh)	55	0.4354507	0.4665680	0.5006094	0.5212816
VIR_750	Volumetric Incentive Rate at 7.50% ($/kWh)	55	0.4489171	0.4809967	0.5160908	0.5374023
VIR_800	Volumetric Incentive Rate at 8.00% ($/kWh)	55	0.4625751	0.4956307	0.5317926	0.5537524
VIR_850	Volumetric Incentive Rate at 8.50% ($/kWh)	55	0.4764205	0.5104655	0.5477097	0.5703269
VIR_900	Volumetric Incentive Rate at 9.00% ($/kWh)	55	0.4904491	0.5254965	0.5638375	0.5871206
VIR_950	Volumetric Incentive Rate at 9.50% ($/kWh)	55	0.5046566	0.5407193	0.5801709	0.6041285
VIR_1000	Volumetric Incentive Rate at 10.00% ($/kWh)	55	0.5190386	0.5561290	0.5967049	0.6213453

Rate Class=4 Project Size Category=10 - 100 KW

Variable	Label	N	10th Pctl	25th Pctl	50th Pctl	Mean
System_Cost	System Cost ($)	5	148000.00	198000.00	304100.00	279820.00
DC_CAP	Capacity - DC (kW)	5	18.3600000	21.6000000	35.1000000	31.7880000
PUC_COST_WATT	System Cost per Watt ($/watt)	5	7.9038282	8.0610022	8.6638177	8.7590629
KWH_YEAR	Expected Annual Generation (kWh)	5	21745.58	25583.04	41572.44	37649.71
CF_YEAR	Annual Capacity Factor (%)	5	13.5205479	13.5205479	13.5205479	13.5205479
LPC_TSRF_DEG	County LPC x TSRF x Degradation	5	1.1844000	1.1844000	1.1844000	1.1844000
CMTR	Combined Marginal Tax Rate	0	.	.	.	.
VIR_600	Volumetric Incentive Rate at 6.00% ($/kWh)	5	0.4956505	0.5055069	0.5433095	0.5492824
VIR_650	Volumetric Incentive Rate at 6.50% ($/kWh)	5	0.5114862	0.5216576	0.5606680	0.5668317
VIR_700	Volumetric Incentive Rate at 7.00% ($/kWh)	5	0.5275641	0.5380551	0.5782918	0.5846492
VIR_750	Volumetric Incentive Rate at 7.50% ($/kWh)	5	0.5438791	0.5546946	0.5961756	0.6027296
VIR_800	Volumetric Incentive Rate at 8.00% ($/kWh)	5	0.5604263	0.5715708	0.6143138	0.6210673
VIR_850	Volumetric Incentive Rate at 8.50% ($/kWh)	5	0.5772005	0.5886786	0.6327010	0.6396566
VIR_900	Volumetric Incentive Rate at 9.00% ($/kWh)	5	0.5941966	0.6060127	0.6513314	0.6584918
VIR_950	Volumetric Incentive Rate at 9.50% ($/kWh)	5	0.6114095	0.6235678	0.6701993	0.6775671
VIR_1000	Volumetric Incentive Rate at 10.00% ($/kWh)	5	0.6288338	0.6413386	0.6892990	0.6968768

STAFF VIR RATES BY RATE CLASS AND PROJECT SIZE CATEGORY -- STEP4
ETO SOLAR PV DATA 2008-2009

PERIOD = 15, COUNTY CLASS = 3, TSRF = 0.90, DEGRADATION = 0.94
LOAN FEE = 0.00, INSURANCE = 0.0022, METER SERVICE = 0, TAX CALC = 0, TAX PREP = 0

The MEANS Procedure

Project Size Category=0 - 10 KW

Variable	Label	N	10th Pctl	25th Pctl	50th Pctl	Mean
System_Cost	System Cost ($)	422	15226.50	19350.00	24946.58	29156.07
DC_CAP	Capacity - DC (kW)	422	2.0000000	2.1600000	3.0000000	3.4284123
PUC_COST_WATT	System Cost per Watt ($/watt)	422	7.0000000	7.6463675	8.2871558	9.4162638
KWH_YEAR	Expected Annual Generation (kWh)	422	1879.81	2254.59	2791.80	3458.71
CF_YEAR	Annual Capacity Factor (%)	422	10.6232877	10.6232877	10.6232877	11.4975005
LPC_TSRF_DEG	County LPC x TSRF x Degradation	422	0.9306000	0.9306000	0.9306000	1.0071810
VIR_600	Volumetric Incentive Rate at 6.00% ($/kWh)	422	0.4787774	0.5402723	0.6245930	0.7077397
VIR_650	Volumetric Incentive Rate at 6.50% ($/kWh)	422	0.4940741	0.5575337	0.6445484	0.7303516
VIR_700	Volumetric Incentive Rate at 7.00% ($/kWh)	422	0.5096046	0.5750590	0.6648089	0.7533092
VIR_750	Volumetric Incentive Rate at 7.50% ($/kWh)	422	0.5253642	0.5928428	0.6853683	0.7766054
VIR_800	Volumetric Incentive Rate at 8.00% ($/kWh)	422	0.5413480	0.6108797	0.7062201	0.8002331
VIR_850	Volumetric Incentive Rate at 8.50% ($/kWh)	422	0.5575512	0.6291640	0.7273581	0.8241851
VIR_900	Volumetric Incentive Rate at 9.00% ($/kWh)	422	0.5739688	0.6476903	0.7487758	0.8484539
VIR_950	Volumetric Incentive Rate at 9.50% ($/kWh)	422	0.5905957	0.6664527	0.7704665	0.8730321
VIR_1000	Volumetric Incentive Rate at 10.00% ($/kWh)	422	0.6074268	0.6854457	0.7924237	0.8979123

Project Size Category=10 - 100 KW

Variable	Label	N	10th Pctl	25th Pctl	50th Pctl	Mean
System_Cost	System Cost ($)	83	95772.00	123996.00	193116.00	245117.44
DC_CAP	Capacity - DC (kW)	83	11.5500000	15.1200000	28.5000000	31.6415663
PUC_COST_WATT	System Cost per Watt ($/watt)	83	6.1600000	6.8959341	7.6869919	7.8073925
KWH_YEAR	Expected Annual Generation (kWh)	83	11260.26	14070.67	26522.10	30230.55
CF_YEAR	Annual Capacity Factor (%)	83	10.6232877	10.6232877	10.6232877	10.9490840
LPC_TSRF_DEG	County LPC x TSRF x Degradation	83	0.9306000	0.9306000	0.9306000	0.9591398
VIR_600	Volumetric Incentive Rate at 6.00% ($/kWh)	83	0.4916478	0.4916478	0.6041811	0.6066490
VIR_650	Volumetric Incentive Rate at 6.50% ($/kWh)	83	0.5073557	0.5073557	0.6234844	0.6260311
VIR_700	Volumetric Incentive Rate at 7.00% ($/kWh)	83	0.5233037	0.5233037	0.6430828	0.6457095
VIR_750	Volumetric Incentive Rate at 7.50% ($/kWh)	83	0.5394870	0.5394870	0.6629702	0.6656782
VIR_800	Volumetric Incentive Rate at 8.00% ($/kWh)	83	0.5559005	0.5559005	0.6831406	0.6859310
VIR_850	Volumetric Incentive Rate at 8.50% ($/kWh)	83	0.5725393	0.5725393	0.7035879	0.7064617
VIR_900	Volumetric Incentive Rate at 9.00% ($/kWh)	83	0.5893981	0.5893981	0.7243056	0.7272640
VIR_950	Volumetric Incentive Rate at 9.50% ($/kWh)	83	0.6064720	0.6064720	0.7452874	0.7483316
VIR_1000	Volumetric Incentive Rate at 10.00% ($/kWh)	83	0.6237556	0.6237556	0.7665271	0.7696580

STAFF VIR RATES BY RATE CLASS AND PROJECT SIZE CATEGORY -- STEP5
ETO SOLAR PV DATA 2008-2009

PERIOD = 15, COUNTY CLASS = 3, TSRF = 0.90, DEGRADATION = 0.94
LOAN FEE = 0.00, INSURANCE = 0.0022, METER SERVICE = 120, TAX CALC = 0, TAX PREP = 0

The MEANS Procedure

Rate Class=1 Project Size Category=0 - 10 KW

Variable	Label	N	10th Pctl	25th Pctl	50th Pctl	Mean
System_Cost	System Cost ($)	242	16743.00	19898.00	24891.50	29057.92
DC_CAP	Capacity - DC (kW)	242	2.0000000	2.2400000	2.8650000	3.3067769
PUC_COST_WATT	System Cost per Watt ($/watt)	242	7.2372928	7.9226765	8.6877381	10.3946767
KWH_YEAR	Expected Annual Generation (kWh)	242	1861.20	2084.54	2666.17	3077.29
CF_YEAR	Annual Capacity Factor (%)	242	10.6232877	10.6232877	10.6232877	10.6232877
LPC_TSRF_DEG	County LPC x TSRF x Degradation	242	0.9306000	0.9306000	0.9306000	0.9306000
CMTR	Combined Marginal Tax Rate	0	.	.	.	.
VIR_600	Volumetric Incentive Rate at 6.00% ($/kWh)	242	0.6223671	0.6717879	0.7397394	0.8820026
VIR_650	Volumetric Incentive Rate at 6.50% ($/kWh)	242	0.6401915	0.6923431	0.7610834	0.9085089
VIR_700	Volumetric Incentive Rate at 7.00% ($/kWh)	242	0.6582883	0.7135726	0.7829665	0.9354203
VIR_750	Volumetric Incentive Rate at 7.50% ($/kWh)	242	0.6766521	0.7346424	0.8057994	0.9627287
VIR_800	Volumetric Incentive Rate at 8.00% ($/kWh)	242	0.6957418	0.7559445	0.8286681	0.9904257
VIR_850	Volumetric Incentive Rate at 8.50% ($/kWh)	242	0.7148631	0.7773747	0.8516969	1.0185027
VIR_900	Volumetric Incentive Rate at 9.00% ($/kWh)	242	0.7340331	0.7988588	0.8750303	1.0469512
VIR_950	Volumetric Incentive Rate at 9.50% ($/kWh)	242	0.7534475	0.8206169	0.8986613	1.0757624
VIR_1000	Volumetric Incentive Rate at 10.00% ($/kWh)	242	0.7731005	0.8431578	0.9225826	1.1049276

Rate Class=1 Project Size Category=10 - 100 KW

Variable	Label	N	10th Pctl	25th Pctl	50th Pctl	Mean
System_Cost	System Cost ($)	70	98901.25	125590.00	202575.00	253340.60
DC_CAP	Capacity - DC (kW)	70	12.1700000	15.3900000	29.7450000	32.9164286
PUC_COST_WATT	System Cost per Watt ($/watt)	70	6.1600000	6.1600000	7.6340321	7.7569232
KWH_YEAR	Expected Annual Generation (kWh)	70	11325.40	14321.93	27680.70	30632.03
CF_YEAR	Annual Capacity Factor (%)	70	10.6232877	10.6232877	10.6232877	10.6232877
LPC_TSRF_DEG	County LPC x TSRF x Degradation	70	0.9306000	0.9306000	0.9306000	0.9306000
CMTR	Combined Marginal Tax Rate	0	.	.	.	.
VIR_600	Volumetric Incentive Rate at 6.00% ($/kWh)	70	0.4952732	0.4966750	0.6156217	0.6246967
VIR_650	Volumetric Incentive Rate at 6.50% ($/kWh)	70	0.5109811	0.5123829	0.6351915	0.6444767
VIR_700	Volumetric Incentive Rate at 7.00% ($/kWh)	70	0.5269291	0.5283310	0.6550029	0.6645591
VIR_750	Volumetric Incentive Rate at 7.50% ($/kWh)	70	0.5431124	0.5445142	0.6750471	0.6849377
VIR_800	Volumetric Incentive Rate at 8.00% ($/kWh)	70	0.5595259	0.5609277	0.6953766	0.7056063
VIR_850	Volumetric Incentive Rate at 8.50% ($/kWh)	70	0.5761647	0.5775665	0.7159851	0.7265585
VIR_900	Volumetric Incentive Rate at 9.00% ($/kWh)	70	0.5930236	0.5944254	0.7368661	0.7477879
VIR_950	Volumetric Incentive Rate at 9.50% ($/kWh)	70	0.6100974	0.6114992	0.7580135	0.7692880
VIR_1000	Volumetric Incentive Rate at 10.00% ($/kWh)	70	0.6273810	0.6287828	0.7794206	0.7910522

STAFF VIR RATES BY RATE CLASS AND PROJECT SIZE CATEGORY -- STEP5
ETO SOLAR PV DATA 2008-2009

PERIOD = 15, COUNTY CLASS = 3, TSRF = 0.90, DEGRADATION = 0.94
LOAN FEE = 0.00, INSURANCE = 0.0022, METER SERVICE = 120, TAX CALC = 0, TAX PREP = 0

The MEANS Procedure

Rate Class=2 Project Size Category=0 - 10 KW

Variable	Label	N	10th Pctl	25th Pctl	50th Pctl	Mean
System_Cost	System Cost ($)	33	21600.00	25300.00	27720.00	30615.11
DC_CAP	Capacity - DC (kW)	33	2.3100000	3.1500000	3.8000000	3.8578788
PUC_COST_WATT	System Cost per Watt ($/watt)	33	7.0000000	7.3842807	7.9591837	8.0384119
KWH_YEAR	Expected Annual Generation (kWh)	33	2345.11	3197.88	3857.76	3916.52
CF_YEAR	Annual Capacity Factor (%)	33	11.5890411	11.5890411	11.5890411	11.5890411
LPC_TSRF_DEG	County LPC x TSRF x Degradation	33	1.0152000	1.0152000	1.0152000	1.0152000
CMTR	Combined Marginal Tax Rate	0	.	.	.	.
VIR_600	Volumetric Incentive Rate at 6.00% ($/kWh)	33	0.5419824	0.5746358	0.6138567	0.6220156
VIR_650	Volumetric Incentive Rate at 6.50% ($/kWh)	33	0.5583448	0.5920708	0.6325699	0.6408053
VIR_700	Volumetric Incentive Rate at 7.00% ($/kWh)	33	0.5749573	0.6095953	0.6515692	0.6598822
VIR_750	Volumetric Incentive Rate at 7.50% ($/kWh)	33	0.5918149	0.6273783	0.6708488	0.6792405
VIR_800	Volumetric Incentive Rate at 8.00% ($/kWh)	33	0.6089123	0.6454143	0.6904026	0.6988742
VIR_850	Volumetric Incentive Rate at 8.50% ($/kWh)	33	0.6262444	0.6636979	0.7102248	0.7187774
VIR_900	Volumetric Incentive Rate at 9.00% ($/kWh)	33	0.6438057	0.6822233	0.7303093	0.7389438
VIR_950	Volumetric Incentive Rate at 9.50% ($/kWh)	33	0.6615910	0.7009849	0.7506498	0.7593674
VIR_1000	Volumetric Incentive Rate at 10.00% ($/kWh)	33	0.6795947	0.7199770	0.7712402	0.7800419

Rate Class=2 Project Size Category=10 - 100 KW

Variable	Label	N	10th Pctl	25th Pctl	50th Pctl	Mean
System_Cost	System Cost ($)	3	67500.00	67500.00	95680.00	86941.67
DC_CAP	Capacity - DC (kW)	3	10.4600000	10.4600000	10.6600000	11.0266667
PUC_COST_WATT	System Cost per Watt ($/watt)	3	6.4531549	6.4531549	8.0000000	7.8710329
KWH_YEAR	Expected Annual Generation (kWh)	3	10618.99	10618.99	10822.03	11194.27
CF_YEAR	Annual Capacity Factor (%)	3	11.5890411	11.5890411	11.5890411	11.5890411
LPC_TSRF_DEG	County LPC x TSRF x Degradation	3	1.0152000	1.0152000	1.0152000	1.0152000
CMTR	Combined Marginal Tax Rate	0	.	.	.	.
VIR_600	Volumetric Incentive Rate at 6.00% ($/kWh)	3	0.4834254	0.4834254	0.5951782	0.5866169
VIR_650	Volumetric Incentive Rate at 6.50% ($/kWh)	3	0.4985096	0.4985096	0.6138781	0.6050153
VIR_700	Volumetric Incentive Rate at 7.00% ($/kWh)	3	0.5138243	0.5138243	0.6328638	0.6236950
VIR_750	Volumetric Incentive Rate at 7.50% ($/kWh)	3	0.5293649	0.5293649	0.6521296	0.6426502
VIR_800	Volumetric Incentive Rate at 8.00% ($/kWh)	3	0.5451267	0.5451267	0.6716695	0.6618751
VIR_850	Volumetric Incentive Rate at 8.50% ($/kWh)	3	0.5611047	0.5611047	0.6914776	0.6813638
VIR_900	Volumetric Incentive Rate at 9.00% ($/kWh)	3	0.5772942	0.5772942	0.7115477	0.7011104
VIR_950	Volumetric Incentive Rate at 9.50% ($/kWh)	3	0.5936900	0.5936900	0.7318737	0.7211087
VIR_1000	Volumetric Incentive Rate at 10.00% ($/kWh)	3	0.6102873	0.6102873	0.7524494	0.7413527

STAFF VIR RATES BY RATE CLASS AND PROJECT SIZE CATEGORY -- STEP5
ETO SOLAR PV DATA 2008-2009

PERIOD = 15, COUNTY CLASS = 3, TSRF = 0.90, DEGRADATION = 0.94
LOAN FEE = 0.00, INSURANCE = 0.0022, METER SERVICE = 120, TAX CALC = 0, TAX PREP = 0

The MEANS Procedure

Rate Class=3 Project Size Category=0 - 10 KW

Variable	Label	N	10th Pctl	25th Pctl	50th Pctl	Mean
System_Cost	System Cost ($)	92	17280.00	18488.78	25919.50	31496.76
DC_CAP	Capacity - DC (kW)	92	2.0400000	2.2800000	3.0900000	3.7725000
PUC_COST_WATT	System Cost per Watt ($/watt)	92	7.0635417	7.5603447	8.0000000	8.2972844
KWH_YEAR	Expected Annual Generation (kWh)	92	2243.59	2507.54	3398.38	4149.00
CF_YEAR	Annual Capacity Factor (%)	92	12.5547945	12.5547945	12.5547945	12.5547945
LPC_TSRF_DEG	County LPC x TSRF x Degradation	92	1.0998000	1.0998000	1.0998000	1.0998000
CMTR	Combined Marginal Tax Rate	0	.	.	.	.
VIR_600	Volumetric Incentive Rate at 6.00% ($/kWh)	92	0.5002915	0.5377184	0.5805165	0.5957693
VIR_650	Volumetric Incentive Rate at 6.50% ($/kWh)	92	0.5153952	0.5540863	0.5982483	0.6136722
VIR_700	Volumetric Incentive Rate at 7.00% ($/kWh)	92	0.5307299	0.5707897	0.6162511	0.6318487
VIR_750	Volumetric Incentive Rate at 7.50% ($/kWh)	92	0.5462907	0.5877394	0.6345195	0.6502934
VIR_800	Volumetric Incentive Rate at 8.00% ($/kWh)	92	0.5621031	0.6049304	0.6530478	0.6690005
VIR_850	Volumetric Incentive Rate at 8.50% ($/kWh)	92	0.5782472	0.6223572	0.6718367	0.6879643
VIR_900	Volumetric Incentive Rate at 9.00% ($/kWh)	92	0.5946048	0.6400146	0.6910630	0.7071790
VIR_950	Volumetric Incentive Rate at 9.50% ($/kWh)	92	0.6111710	0.6578971	0.7105345	0.7266387
VIR_1000	Volumetric Incentive Rate at 10.00% ($/kWh)	92	0.6279407	0.6759993	0.7301473	0.7463374

Rate Class=3 Project Size Category=10 - 100 KW

Variable	Label	N	10th Pctl	25th Pctl	50th Pctl	Mean
System_Cost	System Cost ($)	5	81300.00	154705.00	159600.00	190196.20
DC_CAP	Capacity - DC (kW)	5	10.8000000	17.5500000	22.8000000	26.0160000
PUC_COST_WATT	System Cost per Watt ($/watt)	5	6.8959341	6.9090909	7.4726316	7.5241068
KWH_YEAR	Expected Annual Generation (kWh)	5	11877.84	19301.49	25075.44	28612.40
CF_YEAR	Annual Capacity Factor (%)	5	12.5547945	12.5547945	12.5547945	12.5547945
LPC_TSRF_DEG	County LPC x TSRF x Degradation	5	1.0998000	1.0998000	1.0998000	1.0998000
CMTR	Combined Marginal Tax Rate	0	.	.	.	.
VIR_600	Volumetric Incentive Rate at 6.00% ($/kWh)	5	0.4676646	0.4713222	0.5094425	0.5136900
VIR_650	Volumetric Incentive Rate at 6.50% ($/kWh)	5	0.4825438	0.4862298	0.5255661	0.5299246
VIR_700	Volumetric Incentive Rate at 7.00% ($/kWh)	5	0.4976505	0.5013653	0.5419361	0.5464073
VIR_750	Volumetric Incentive Rate at 7.50% ($/kWh)	5	0.5129800	0.5167240	0.5585475	0.5631332
VIR_800	Volumetric Incentive Rate at 8.00% ($/kWh)	5	0.5285276	0.5323013	0.5753954	0.5800971
VIR_850	Volumetric Incentive Rate at 8.50% ($/kWh)	5	0.5442885	0.5480923	0.5924744	0.5972938
VIR_900	Volumetric Incentive Rate at 9.00% ($/kWh)	5	0.5602580	0.5640923	0.6097794	0.6147180
VIR_950	Volumetric Incentive Rate at 9.50% ($/kWh)	5	0.5764311	0.5802962	0.6273050	0.6323643
VIR_1000	Volumetric Incentive Rate at 10.00% ($/kWh)	5	0.5928029	0.5966992	0.6450459	0.6502275

STAFF VIR RATES BY RATE CLASS AND PROJECT SIZE CATEGORY -- STEP5
ETO SOLAR PV DATA 2008-2009

PERIOD = 15, COUNTY CLASS = 3, TSRF = 0.90, DEGRADATION = 0.94
LOAN FEE = 0.00, INSURANCE = 0.0022, METER SERVICE = 120, TAX CALC = 0, TAX PREP = 0

The MEANS Procedure

Rate Class=4 Project Size Category=0 - 10 KW

Variable	Label	N	10th Pctl	25th Pctl	50th Pctl	Mean
System_Cost	System Cost ($)	55	13700.00	14050.00	18000.00	24797.19
DC_CAP	Capacity - DC (kW)	55	2.0000000	2.0000000	2.1000000	3.1303636
PUC_COST_WATT	System Cost per Watt ($/watt)	55	6.5238095	6.9900000	7.5000000	7.8097056
KWH_YEAR	Expected Annual Generation (kWh)	55	2368.80	2368.80	2487.24	3707.60
CF_YEAR	Annual Capacity Factor (%)	55	13.5205479	13.5205479	13.5205479	13.5205479
LPC_TSRF_DEG	County LPC x TSRF x Degradation	55	1.1844000	1.1844000	1.1844000	1.1844000
CMTR	Combined Marginal Tax Rate	0	.	.	.	.
VIR_600	Volumetric Incentive Rate at 6.00% ($/kWh)	55	0.4573555	0.4884187	0.5197493	0.5292834
VIR_650	Volumetric Incentive Rate at 6.50% ($/kWh)	55	0.4704263	0.5030076	0.5347760	0.5449306
VIR_700	Volumetric Incentive Rate at 7.00% ($/kWh)	55	0.4838827	0.5172265	0.5500324	0.5608170
VIR_750	Volumetric Incentive Rate at 7.50% ($/kWh)	55	0.4979373	0.5316552	0.5655138	0.5769377
VIR_800	Volumetric Incentive Rate at 8.00% ($/kWh)	55	0.5115454	0.5462892	0.5812155	0.5932879
VIR_850	Volumetric Incentive Rate at 8.50% ($/kWh)	55	0.5253403	0.5611240	0.5971327	0.6098623
VIR_900	Volumetric Incentive Rate at 9.00% ($/kWh)	55	0.5393177	0.5761551	0.6132605	0.6266561
VIR_950	Volumetric Incentive Rate at 9.50% ($/kWh)	55	0.5534733	0.5913778	0.6295939	0.6436639
VIR_1000	Volumetric Incentive Rate at 10.00% ($/kWh)	55	0.5678028	0.6067876	0.6461279	0.6608807

Rate Class=4 Project Size Category=10 - 100 KW

Variable	Label	N	10th Pctl	25th Pctl	50th Pctl	Mean
System_Cost	System Cost ($)	5	148000.00	198000.00	304100.00	279820.00
DC_CAP	Capacity - DC (kW)	5	18.3600000	21.6000000	35.1000000	31.7880000
PUC_COST_WATT	System Cost per Watt ($/watt)	5	7.9038282	8.0610022	8.6638177	8.7590629
KWH_YEAR	Expected Annual Generation (kWh)	5	21745.58	25583.04	41572.44	37649.71
CF_YEAR	Annual Capacity Factor (%)	5	13.5205479	13.5205479	13.5205479	13.5205479
LPC_TSRF_DEG	County LPC x TSRF x Degradation	5	1.1844000	1.1844000	1.1844000	1.1844000
CMTR	Combined Marginal Tax Rate	0	.	.	.	.
VIR_600	Volumetric Incentive Rate at 6.00% ($/kWh)	5	0.4980155	0.5110252	0.5461961	0.5528682
VIR_650	Volumetric Incentive Rate at 6.50% ($/kWh)	5	0.5138513	0.5271759	0.5635545	0.5704175
VIR_700	Volumetric Incentive Rate at 7.00% ($/kWh)	5	0.5299291	0.5435735	0.5811783	0.5882351
VIR_750	Volumetric Incentive Rate at 7.50% ($/kWh)	5	0.5462441	0.5602129	0.5990621	0.6063155
VIR_800	Volumetric Incentive Rate at 8.00% ($/kWh)	5	0.5627913	0.5770892	0.6172004	0.6246531
VIR_850	Volumetric Incentive Rate at 8.50% ($/kWh)	5	0.5795655	0.5941970	0.6355875	0.6432424
VIR_900	Volumetric Incentive Rate at 9.00% ($/kWh)	5	0.5965616	0.6115311	0.6542179	0.6620776
VIR_950	Volumetric Incentive Rate at 9.50% ($/kWh)	5	0.6137745	0.6290862	0.6730858	0.6811530
VIR_1000	Volumetric Incentive Rate at 10.00% ($/kWh)	5	0.6311988	0.6468570	0.6921856	0.7004627

STAFF VIR RATES BY RATE CLASS AND PROJECT SIZE CATEGORY -- STEP5
ETO SOLAR PV DATA 2008-2009

PERIOD = 15, COUNTY CLASS = 3, TSRF = 0.90, DEGRADATION = 0.94
LOAN FEE = 0.00, INSURANCE = 0.0022, METER SERVICE = 120, TAX CALC = 0, TAX PREP = 0

The MEANS Procedure

Project Size Category=0 - 10 KW

Variable	Label	N	10th Pctl	25th Pctl	50th Pctl	Mean
System_Cost	System Cost ($)	422	15226.50	19350.00	24946.58	29156.07
DC_CAP	Capacity - DC (kW)	422	2.0000000	2.1600000	3.0000000	3.4284123
PUC_COST_WATT	System Cost per Watt ($/watt)	422	7.0000000	7.6463675	8.2871558	9.4162638
KWH_YEAR	Expected Annual Generation (kWh)	422	1879.81	2254.59	2791.80	3458.71
CF_YEAR	Annual Capacity Factor (%)	422	10.6232877	10.6232877	10.6232877	11.4975005
LPC_TSRF_DEG	County LPC x TSRF x Degradation	422	0.9306000	0.9306000	0.9306000	1.0071810
VIR_600	Volumetric Incentive Rate at 6.00% ($/kWh)	422	0.5058180	0.5785490	0.6627298	0.7532998
VIR_650	Volumetric Incentive Rate at 6.50% ($/kWh)	422	0.5215259	0.5960244	0.6828430	0.7759117
VIR_700	Volumetric Incentive Rate at 7.00% ($/kWh)	422	0.5374739	0.6136337	0.7032636	0.7988693
VIR_750	Volumetric Incentive Rate at 7.50% ($/kWh)	422	0.5536572	0.6315027	0.7239854	0.8221655
VIR_800	Volumetric Incentive Rate at 8.00% ($/kWh)	422	0.5700707	0.6496260	0.7447987	0.8457932
VIR_850	Volumetric Incentive Rate at 8.50% ($/kWh)	422	0.5867095	0.6679979	0.7655234	0.8697452
VIR_900	Volumetric Incentive Rate at 9.00% ($/kWh)	422	0.6035684	0.6866130	0.7865223	0.8940139
VIR_950	Volumetric Incentive Rate at 9.50% ($/kWh)	422	0.6206422	0.7054653	0.8081155	0.9185922
VIR_1000	Volumetric Incentive Rate at 10.00% ($/kWh)	422	0.6379258	0.7245493	0.8301329	0.9434724

Project Size Category=10 - 100 KW

Variable	Label	N	10th Pctl	25th Pctl	50th Pctl	Mean
System_Cost	System Cost ($)	83	95772.00	123996.00	193116.00	245117.44
DC_CAP	Capacity - DC (kW)	83	11.5500000	15.1200000	28.5000000	31.6415663
PUC_COST_WATT	System Cost per Watt ($/watt)	83	6.1600000	6.8959341	7.6869919	7.8073925
KWH_YEAR	Expected Annual Generation (kWh)	83	11260.26	14070.67	26522.10	30230.55
CF_YEAR	Annual Capacity Factor (%)	83	10.6232877	10.6232877	10.6232877	10.9490840
LPC_TSRF_DEG	County LPC x TSRF x Degradation	83	0.9306000	0.9306000	0.9306000	0.9591398
VIR_600	Volumetric Incentive Rate at 6.00% ($/kWh)	83	0.4951282	0.4966750	0.6120535	0.6123062
VIR_650	Volumetric Incentive Rate at 6.50% ($/kWh)	83	0.5108361	0.5123829	0.6313568	0.6316883
VIR_700	Volumetric Incentive Rate at 7.00% ($/kWh)	83	0.5267841	0.5283310	0.6509551	0.6513667
VIR_750	Volumetric Incentive Rate at 7.50% ($/kWh)	83	0.5429674	0.5445142	0.6708426	0.6713354
VIR_800	Volumetric Incentive Rate at 8.00% ($/kWh)	83	0.5593809	0.5609277	0.6910130	0.6915882
VIR_850	Volumetric Incentive Rate at 8.50% ($/kWh)	83	0.5760197	0.5775665	0.7114602	0.7121189
VIR_900	Volumetric Incentive Rate at 9.00% ($/kWh)	83	0.5928785	0.5944254	0.7321779	0.7329212
VIR_950	Volumetric Incentive Rate at 9.50% ($/kWh)	83	0.6099524	0.6114992	0.7531598	0.7539888
VIR_1000	Volumetric Incentive Rate at 10.00% ($/kWh)	83	0.6272360	0.6287828	0.7743994	0.7753152

STAFF VIR RATES BY RATE CLASS AND PROJECT SIZE CATEGORY -- STEP6
ETO SOLAR PV DATA 2008-2009

PERIOD = 15, COUNTY CLASS = 3, TSRF = 0.90, DEGRADATION = 0.94
LOAN FEE = 0.01, INSURANCE = 0.0022, METER SERVICE = 120, TAX CALC = 0, TAX PREP = 0

The MEANS Procedure

Rate Class=1 Project Size Category=0 - 10 KW

Variable	Label	N	10th Pctl	25th Pctl	50th Pctl	Mean
System_Cost	System Cost ($)	242	16743.00	19898.00	24891.50	29057.92
DC_CAP	Capacity - DC (kW)	242	2.0000000	2.2400000	2.8650000	3.3067769
PUC_COST_WATT	System Cost per Watt ($/watt)	242	7.2372928	7.9226765	8.6877381	10.3946767
KWH_YEAR	Expected Annual Generation (kWh)	242	1861.20	2084.54	2666.17	3077.29
CF_YEAR	Annual Capacity Factor (%)	242	10.6232877	10.6232877	10.6232877	10.6232877
LPC_TSRF_DEG	County LPC x TSRF x Degradation	242	0.9306000	0.9306000	0.9306000	0.9306000
CMTR	Combined Marginal Tax Rate	0	.	.	.	.
VIR_600	Volumetric Incentive Rate at 6.00% ($/kWh)	242	0.6277808	0.6779096	0.7463425	0.8900532
VIR_650	Volumetric Incentive Rate at 6.50% ($/kWh)	242	0.6457834	0.6989030	0.7675808	0.9168245
VIR_700	Volumetric Incentive Rate at 7.00% ($/kWh)	242	0.6640612	0.7202419	0.7901443	0.9440050
VIR_750	Volumetric Incentive Rate at 7.50% ($/kWh)	242	0.6826086	0.7414551	0.8132056	0.9715865
VIR_800	Volumetric Incentive Rate at 8.00% ($/kWh)	242	0.7020988	0.7629701	0.8361604	0.9995605
VIR_850	Volumetric Incentive Rate at 8.50% ($/kWh)	242	0.7212077	0.7844853	0.8594195	1.0279183
VIR_900	Volumetric Incentive Rate at 9.00% ($/kWh)	242	0.7405695	0.8061842	0.8829863	1.0566512
VIR_950	Volumetric Incentive Rate at 9.50% ($/kWh)	242	0.7601780	0.8281875	0.9068536	1.0857506
VIR_1000	Volumetric Incentive Rate at 10.00% ($/kWh)	242	0.7800275	0.8511827	0.9310141	1.1152074

Rate Class=1 Project Size Category=10 - 100 KW

Variable	Label	N	10th Pctl	25th Pctl	50th Pctl	Mean
System_Cost	System Cost ($)	70	98901.25	125590.00	202575.00	253340.60
DC_CAP	Capacity - DC (kW)	70	12.1700000	15.3900000	29.7450000	32.9164286
PUC_COST_WATT	System Cost per Watt ($/watt)	70	6.1600000	6.1600000	7.6340321	7.7569232
KWH_YEAR	Expected Annual Generation (kWh)	70	11325.40	14321.93	27680.70	30632.03
CF_YEAR	Annual Capacity Factor (%)	70	10.6232877	10.6232877	10.6232877	10.6232877
LPC_TSRF_DEG	County LPC x TSRF x Degradation	70	0.9306000	0.9306000	0.9306000	0.9306000
CMTR	Combined Marginal Tax Rate	0	.	.	.	.
VIR_600	Volumetric Incentive Rate at 6.00% ($/kWh)	70	0.5000441	0.5014459	0.6215655	0.6307044
VIR_650	Volumetric Incentive Rate at 6.50% ($/kWh)	70	0.5159090	0.5173109	0.6413310	0.6506822
VIR_700	Volumetric Incentive Rate at 7.00% ($/kWh)	70	0.5320165	0.5334184	0.6613040	0.6709654
VIR_750	Volumetric Incentive Rate at 7.50% ($/kWh)	70	0.5483616	0.5497635	0.6815487	0.6915478
VIR_800	Volumetric Incentive Rate at 8.00% ($/kWh)	70	0.5649393	0.5663411	0.7020815	0.7124231
VIR_850	Volumetric Incentive Rate at 8.50% ($/kWh)	70	0.5817444	0.5831463	0.7228961	0.7335848
VIR_900	Volumetric Incentive Rate at 9.00% ($/kWh)	70	0.5987719	0.6001737	0.7439859	0.7550265
VIR_950	Volumetric Incentive Rate at 9.50% ($/kWh)	70	0.6160165	0.6174183	0.7653447	0.7767415
VIR_1000	Volumetric Incentive Rate at 10.00% ($/kWh)	70	0.6334729	0.6348747	0.7869659	0.7987234

STAFF VIR RATES BY RATE CLASS AND PROJECT SIZE CATEGORY -- STEP6
ETO SOLAR PV DATA 2008-2009

PERIOD = 15, COUNTY CLASS = 3, TSRF = 0.90, DEGRADATION = 0.94
LOAN FEE = 0.01, INSURANCE = 0.0022, METER SERVICE = 120, TAX CALC = 0, TAX PREP = 0

The MEANS Procedure

Rate Class=2 Project Size Category=0 - 10 KW

Variable	Label	N	10th Pctl	25th Pctl	50th Pctl	Mean
System_Cost	System Cost ($)	33	21600.00	25300.00	27720.00	30615.11
DC_CAP	Capacity - DC (kW)	33	2.3100000	3.1500000	3.8000000	3.8578788
PUC_COST_WATT	System Cost per Watt ($/watt)	33	7.0000000	7.3842807	7.9591837	8.0384119
KWH_YEAR	Expected Annual Generation (kWh)	33	2345.11	3197.88	3857.76	3916.52
CF_YEAR	Annual Capacity Factor (%)	33	11.5890411	11.5890411	11.5890411	11.5890411
LPC_TSRF_DEG	County LPC x TSRF x Degradation	33	1.0152000	1.0152000	1.0152000	1.0152000
CMTR	Combined Marginal Tax Rate	0	.	.	.	.
VIR_600	Volumetric Incentive Rate at 6.00% ($/kWh)	33	0.5469521	0.5799604	0.6195403	0.6277225
VIR_650	Volumetric Incentive Rate at 6.50% ($/kWh)	33	0.5634781	0.5974859	0.6384407	0.6467000
VIR_700	Volumetric Incentive Rate at 7.00% ($/kWh)	33	0.5802567	0.6151856	0.6576300	0.6659677
VIR_750	Volumetric Incentive Rate at 7.50% ($/kWh)	33	0.5972829	0.6331465	0.6771023	0.6855196
VIR_800	Volumetric Incentive Rate at 8.00% ($/kWh)	33	0.6145513	0.6513628	0.6968518	0.7053497
VIR_850	Volumetric Incentive Rate at 8.50% ($/kWh)	33	0.6320566	0.6698292	0.7168722	0.7254518
VIR_900	Volumetric Incentive Rate at 9.00% ($/kWh)	33	0.6497936	0.6885399	0.7371574	0.7458200
VIR_950	Volumetric Incentive Rate at 9.50% ($/kWh)	33	0.6677567	0.7074891	0.7577014	0.7664478
VIR_1000	Volumetric Incentive Rate at 10.00% ($/kWh)	33	0.6859405	0.7266711	0.7784977	0.7873290

Rate Class=2 Project Size Category=10 - 100 KW

Variable	Label	N	10th Pctl	25th Pctl	50th Pctl	Mean
System_Cost	System Cost ($)	3	67500.00	67500.00	95680.00	86941.67
DC_CAP	Capacity - DC (kW)	3	10.4600000	10.4600000	10.6600000	11.0266667
PUC_COST_WATT	System Cost per Watt ($/watt)	3	6.4531549	6.4531549	8.0000000	7.8710329
KWH_YEAR	Expected Annual Generation (kWh)	3	10618.99	10618.99	10822.03	11194.27
CF_YEAR	Annual Capacity Factor (%)	3	11.5890411	11.5890411	11.5890411	11.5890411
LPC_TSRF_DEG	County LPC x TSRF x Degradation	3	1.0152000	1.0152000	1.0152000	1.0152000
CMTR	Combined Marginal Tax Rate	0	.	.	.	.
VIR_600	Volumetric Incentive Rate at 6.00% ($/kWh)	3	0.4880068	0.4880068	0.6008578	0.5922049
VIR_650	Volumetric Incentive Rate at 6.50% ($/kWh)	3	0.5032418	0.5032418	0.6197447	0.6107873
VIR_700	Volumetric Incentive Rate at 7.00% ($/kWh)	3	0.5187097	0.5187097	0.6389203	0.6296538
VIR_750	Volumetric Incentive Rate at 7.50% ($/kWh)	3	0.5344057	0.5344057	0.6583787	0.6487986
VIR_800	Volumetric Incentive Rate at 8.00% ($/kWh)	3	0.5503251	0.5503251	0.6781140	0.6682157
VIR_850	Volumetric Incentive Rate at 8.50% ($/kWh)	3	0.5664629	0.5664629	0.6981201	0.6878993
VIR_900	Volumetric Incentive Rate at 9.00% ($/kWh)	3	0.5828143	0.5828143	0.7183909	0.7078434
VIR_950	Volumetric Incentive Rate at 9.50% ($/kWh)	3	0.5993741	0.5993741	0.7389202	0.7280417
VIR_1000	Volumetric Incentive Rate at 10.00% ($/kWh)	3	0.6161373	0.6161373	0.7597017	0.7484881

STAFF VIR RATES BY RATE CLASS AND PROJECT SIZE CATEGORY -- STEP6
ETO SOLAR PV DATA 2008-2009

PERIOD = 15, COUNTY CLASS = 3, TSRF = 0.90, DEGRADATION = 0.94
LOAN FEE = 0.01, INSURANCE = 0.0022, METER SERVICE = 120, TAX CALC = 0, TAX PREP = 0

The MEANS Procedure

Rate Class=3 Project Size Category=0 - 10 KW

Variable	Label	N	10th Pctl	25th Pctl	50th Pctl	Mean
System_Cost	System Cost ($)	92	17280.00	18488.78	25919.50	31496.76
DC_CAP	Capacity - DC (kW)	92	2.0400000	2.2800000	3.0900000	3.7725000
PUC_COST_WATT	System Cost per Watt ($/watt)	92	7.0635417	7.5603447	8.0000000	8.2972844
KWH_YEAR	Expected Annual Generation (kWh)	92	2243.59	2507.54	3398.38	4149.00
CF_YEAR	Annual Capacity Factor (%)	92	12.5547945	12.5547945	12.5547945	12.5547945
LPC_TSRF_DEG	County LPC x TSRF x Degradation	92	1.0998000	1.0998000	1.0998000	1.0998000
CMTR	Combined Marginal Tax Rate	0	.	.	.	.
VIR_600	Volumetric Incentive Rate at 6.00% ($/kWh)	92	0.5048788	0.5426490	0.5859021	0.6012069
VIR_650	Volumetric Incentive Rate at 6.50% ($/kWh)	92	0.5201336	0.5592477	0.6038111	0.6192887
VIR_700	Volumetric Incentive Rate at 7.00% ($/kWh)	92	0.5356216	0.5761181	0.6219940	0.6376471
VIR_750	Volumetric Incentive Rate at 7.50% ($/kWh)	92	0.5513380	0.5932373	0.6404450	0.6562762
VIR_800	Volumetric Incentive Rate at 8.00% ($/kWh)	92	0.5673556	0.6106002	0.6591586	0.6751703
VIR_850	Volumetric Incentive Rate at 8.50% ($/kWh)	92	0.5836610	0.6282012	0.6782000	0.6943238
VIR_900	Volumetric Incentive Rate at 9.00% ($/kWh)	92	0.6001822	0.6460352	0.6976186	0.7137306
VIR_950	Volumetric Incentive Rate at 9.50% ($/kWh)	92	0.6169141	0.6640965	0.7172848	0.7333849
VIR_1000	Volumetric Incentive Rate at 10.00% ($/kWh)	92	0.6338515	0.6823797	0.7370120	0.7532806

Rate Class=3 Project Size Category=10 - 100 KW

Variable	Label	N	10th Pctl	25th Pctl	50th Pctl	Mean
System_Cost	System Cost ($)	5	81300.00	154705.00	159600.00	190196.20
DC_CAP	Capacity - DC (kW)	5	10.8000000	17.5500000	22.8000000	26.0160000
PUC_COST_WATT	System Cost per Watt ($/watt)	5	6.8959341	6.9090909	7.4726316	7.5241068
KWH_YEAR	Expected Annual Generation (kWh)	5	11877.84	19301.49	25075.44	28612.40
CF_YEAR	Annual Capacity Factor (%)	5	12.5547945	12.5547945	12.5547945	12.5547945
LPC_TSRF_DEG	County LPC x TSRF x Degradation	5	1.0998000	1.0998000	1.0998000	1.0998000
CMTR	Combined Marginal Tax Rate	0	.	.	.	.
VIR_600	Volumetric Incentive Rate at 6.00% ($/kWh)	5	0.4721838	0.4758500	0.5143396	0.5186208
VIR_650	Volumetric Incentive Rate at 6.50% ($/kWh)	5	0.4872118	0.4909067	0.5306244	0.5350177
VIR_700	Volumetric Incentive Rate at 7.00% ($/kWh)	5	0.5024695	0.5061935	0.5471581	0.5516653
VIR_750	Volumetric Incentive Rate at 7.50% ($/kWh)	5	0.5179523	0.5217058	0.5639357	0.5685585
VIR_800	Volumetric Incentive Rate at 8.00% ($/kWh)	5	0.5336554	0.5374389	0.5809520	0.5856920
VIR_850	Volumetric Incentive Rate at 8.50% ($/kWh)	5	0.5495739	0.5533878	0.5982018	0.6030607
VIR_900	Volumetric Incentive Rate at 9.00% ($/kWh)	5	0.5657031	0.5695477	0.6156798	0.6206591
VIR_950	Volumetric Incentive Rate at 9.50% ($/kWh)	5	0.5820379	0.5859137	0.6333807	0.6384819
VIR_1000	Volumetric Incentive Rate at 10.00% ($/kWh)	5	0.5985734	0.6024808	0.6512991	0.6565237

STAFF VIR RATES BY RATE CLASS AND PROJECT SIZE CATEGORY -- STEP6
ETO SOLAR PV DATA 2008-2009

PERIOD = 15, COUNTY CLASS = 3, TSRF = 0.90, DEGRADATION = 0.94
LOAN FEE = 0.01, INSURANCE = 0.0022, METER SERVICE = 120, TAX CALC = 0, TAX PREP = 0

The MEANS Procedure

Rate Class=4 Project Size Category=0 - 10 KW

Variable	Label	N	10th Pctl	25th Pctl	50th Pctl	Mean
System_Cost	System Cost ($)	55	13700.00	14050.00	18000.00	24797.19
DC_CAP	Capacity - DC (kW)	55	2.0000000	2.0000000	2.1000000	3.1303636
PUC_COST_WATT	System Cost per Watt ($/watt)	55	6.5238095	6.9900000	7.5000000	7.8097056
KWH_YEAR	Expected Annual Generation (kWh)	55	2368.80	2368.80	2487.24	3707.60
CF_YEAR	Annual Capacity Factor (%)	55	13.5205479	13.5205479	13.5205479	13.5205479
LPC_TSRF_DEG	County LPC x TSRF x Degradation	55	1.1844000	1.1844000	1.1844000	1.1844000
CMTR	Combined Marginal Tax Rate	0	.	.	.	.
VIR_600	Volumetric Incentive Rate at 6.00% ($/kWh)	55	0.4613254	0.4929826	0.5243133	0.5340359
VIR_650	Volumetric Incentive Rate at 6.50% ($/kWh)	55	0.4745270	0.5074012	0.5394902	0.5498395
VIR_700	Volumetric Incentive Rate at 7.00% ($/kWh)	55	0.4883071	0.5217624	0.5548992	0.5658848
VIR_750	Volumetric Incentive Rate at 7.50% ($/kWh)	55	0.5022893	0.5363354	0.5705354	0.5821667
VIR_800	Volumetric Incentive Rate at 8.00% ($/kWh)	55	0.5160336	0.5511157	0.5863942	0.5986803
VIR_850	Volumetric Incentive Rate at 8.50% ($/kWh)	55	0.5299664	0.5660989	0.6024705	0.6154205
VIR_900	Volumetric Incentive Rate at 9.00% ($/kWh)	55	0.5440836	0.5812802	0.6187595	0.6323822
VIR_950	Volumetric Incentive Rate at 9.50% ($/kWh)	55	0.5583807	0.5966552	0.6352563	0.6495601
VIR_1000	Volumetric Incentive Rate at 10.00% ($/kWh)	55	0.5728535	0.6122190	0.6519557	0.6669491

Rate Class=4 Project Size Category=10 - 100 KW

Variable	Label	N	10th Pctl	25th Pctl	50th Pctl	Mean
System_Cost	System Cost ($)	5	148000.00	198000.00	304100.00	279820.00
DC_CAP	Capacity - DC (kW)	5	18.3600000	21.6000000	35.1000000	31.7880000
PUC_COST_WATT	System Cost per Watt ($/watt)	5	7.9038282	8.0610022	8.6638177	8.7590629
KWH_YEAR	Expected Annual Generation (kWh)	5	21745.58	25583.04	41572.44	37649.71
CF_YEAR	Annual Capacity Factor (%)	5	13.5205479	13.5205479	13.5205479	13.5205479
LPC_TSRF_DEG	County LPC x TSRF x Degradation	5	1.1844000	1.1844000	1.1844000	1.1844000
CMTR	Combined Marginal Tax Rate	0	.	.	.	.
VIR_600	Volumetric Incentive Rate at 6.00% ($/kWh)	5	0.5028252	0.5159306	0.5514682	0.5581984
VIR_650	Volumetric Incentive Rate at 6.50% ($/kWh)	5	0.5188193	0.5322428	0.5690003	0.5759231
VIR_700	Volumetric Incentive Rate at 7.00% ($/kWh)	5	0.5350579	0.5488043	0.5868003	0.5939189
VIR_750	Volumetric Incentive Rate at 7.50% ($/kWh)	5	0.5515361	0.5656102	0.6048629	0.6121801
VIR_800	Volumetric Incentive Rate at 8.00% ($/kWh)	5	0.5682487	0.5826551	0.6231826	0.6307011
VIR_850	Volumetric Incentive Rate at 8.50% ($/kWh)	5	0.5851907	0.5999340	0.6417536	0.6494763
VIR_900	Volumetric Incentive Rate at 9.00% ($/kWh)	5	0.6023568	0.6174415	0.6605703	0.6684998
VIR_950	Volumetric Incentive Rate at 9.50% ($/kWh)	5	0.6197418	0.6351721	0.6796269	0.6877659
VIR_1000	Volumetric Incentive Rate at 10.00% ($/kWh)	5	0.6373403	0.6531207	0.6989176	0.7072687

STAFF VIR RATES BY RATE CLASS AND PROJECT SIZE CATEGORY -- STEP6
ETO SOLAR PV DATA 2008-2009

PERIOD = 15, COUNTY CLASS = 3, TSRF = 0.90, DEGRADATION = 0.94
LOAN FEE = 0.01, INSURANCE = 0.0022, METER SERVICE = 120, TAX CALC = 0, TAX PREP = 0

The MEANS Procedure

Project Size Category=0 - 10 KW

Variable	Label	N	10th Pctl	25th Pctl	50th Pctl	Mean
System_Cost	System Cost ($)	422	15226.50	19350.00	24946.58	29156.07
DC_CAP	Capacity - DC (kW)	422	2.0000000	2.1600000	3.0000000	3.4284123
PUC_COST_WATT	System Cost per Watt ($/watt)	422	7.0000000	7.6463675	8.2871558	9.4162638
KWH_YEAR	Expected Annual Generation (kWh)	422	1879.81	2254.59	2791.80	3458.71
CF_YEAR	Annual Capacity Factor (%)	422	10.6232877	10.6232877	10.6232877	11.4975005
LPC_TSRF_DEG	County LPC x TSRF x Degradation	422	0.9306000	0.9306000	0.9306000	1.0071810
VIR_600	Volumetric Incentive Rate at 6.00% ($/kWh)	422	0.5105889	0.5839481	0.6688386	0.7601676
VIR_650	Volumetric Incentive Rate at 6.50% ($/kWh)	422	0.5264538	0.6014657	0.6891529	0.7830056
VIR_700	Volumetric Incentive Rate at 7.00% ($/kWh)	422	0.5425613	0.6192510	0.7097778	0.8061928
VIR_750	Volumetric Incentive Rate at 7.50% ($/kWh)	422	0.5589064	0.6372987	0.7307068	0.8297219
VIR_800	Volumetric Incentive Rate at 8.00% ($/kWh)	422	0.5754841	0.6556032	0.7515414	0.8535859
VIR_850	Volumetric Incentive Rate at 8.50% ($/kWh)	422	0.5922892	0.6741589	0.7724734	0.8777774
VIR_900	Volumetric Incentive Rate at 9.00% ($/kWh)	422	0.6093167	0.6929601	0.7936882	0.9022889
VIR_950	Volumetric Incentive Rate at 9.50% ($/kWh)	422	0.6265613	0.7120010	0.8156558	0.9271129
VIR_1000	Volumetric Incentive Rate at 10.00% ($/kWh)	422	0.6440177	0.7312758	0.8378933	0.9522418

Project Size Category=10 - 100 KW

Variable	Label	N	10th Pctl	25th Pctl	50th Pctl	Mean
System_Cost	System Cost ($)	83	95772.00	123996.00	193116.00	245117.44
DC_CAP	Capacity - DC (kW)	83	11.5500000	15.1200000	28.5000000	31.6415663
PUC_COST_WATT	System Cost per Watt ($/watt)	83	6.1600000	6.8959341	7.6869919	7.8073925
KWH_YEAR	Expected Annual Generation (kWh)	83	11260.26	14070.67	26522.10	30230.55
CF_YEAR	Annual Capacity Factor (%)	83	10.6232877	10.6232877	10.6232877	10.9490840
LPC_TSRF_DEG	County LPC x TSRF x Degradation	83	0.9306000	0.9306000	0.9306000	0.9591398
VIR_600	Volumetric Incentive Rate at 6.00% ($/kWh)	83	0.4998991	0.5014459	0.6179163	0.6181930
VIR_650	Volumetric Incentive Rate at 6.50% ($/kWh)	83	0.5157640	0.5173109	0.6374126	0.6377689
VIR_700	Volumetric Incentive Rate at 7.00% ($/kWh)	83	0.5318715	0.5334184	0.6572070	0.6576441
VIR_750	Volumetric Incentive Rate at 7.50% ($/kWh)	83	0.5482166	0.5497635	0.6772933	0.6778125
VIR_800	Volumetric Incentive Rate at 8.00% ($/kWh)	83	0.5647943	0.5663411	0.6976654	0.6982678
VIR_850	Volumetric Incentive Rate at 8.50% ($/kWh)	83	0.5815994	0.5831463	0.7183171	0.7190038
VIR_900	Volumetric Incentive Rate at 9.00% ($/kWh)	83	0.5986269	0.6001737	0.7392420	0.7400142
VIR_950	Volumetric Incentive Rate at 9.50% ($/kWh)	83	0.6158715	0.6174183	0.7604337	0.7612924
VIR_1000	Volumetric Incentive Rate at 10.00% ($/kWh)	83	0.6333279	0.6348747	0.7818857	0.7828321

STAFF VIR RATES BY RATE CLASS AND PROJECT SIZE CATEGORY -- STEP7
ETO SOLAR PV DATA 2008-2009

PERIOD = 15, COUNTY CLASS = 3, TSRF = 0.90, DEGRADATION = 0.94
LOAN FEE = 0.01, INSURANCE = 0.0022, METER SERVICE = 120, TAX CALC = 1, TAX PREP = 0

The MEANS Procedure

Rate Class=1 Project Size Category=0 - 10 KW

Variable	Label	N	10th Pctl	25th Pctl	50th Pctl	Mean
System_Cost	System Cost ($)	242	16743.00	19898.00	24891.50	29057.92
DC_CAP	Capacity - DC (kW)	242	2.0000000	2.2400000	2.8650000	3.3067769
PUC_COST_WATT	System Cost per Watt ($/watt)	242	7.2372928	7.9226765	8.6877381	10.3946767
KWH_YEAR	Expected Annual Generation (kWh)	242	1861.20	2084.54	2666.17	3077.29
CF_YEAR	Annual Capacity Factor (%)	242	10.6232877	10.6232877	10.6232877	10.6232877
LPC_TSRF_DEG	County LPC x TSRF x Degradation	242	0.9306000	0.9306000	0.9306000	0.9306000
CMTR	Combined Marginal Tax Rate	242	0.3795000	0.3795000	0.3795000	0.3795000
VIR_600	Volumetric Incentive Rate at 6.00% ($/kWh)	242	0.6319161	0.6779096	0.7463425	0.8911267
VIR_650	Volumetric Incentive Rate at 6.50% ($/kWh)	242	0.6502258	0.6989030	0.7683004	0.9178980
VIR_700	Volumetric Incentive Rate at 7.00% ($/kWh)	242	0.6685036	0.7202419	0.7905939	0.9450785
VIR_750	Volumetric Incentive Rate at 7.50% ($/kWh)	242	0.6870511	0.7414551	0.8135354	0.9726600
VIR_800	Volumetric Incentive Rate at 8.00% ($/kWh)	242	0.7058624	0.7629701	0.8368152	1.0006340
VIR_850	Volumetric Incentive Rate at 8.50% ($/kWh)	242	0.7249319	0.7844853	0.8604143	1.0289918
VIR_900	Volumetric Incentive Rate at 9.00% ($/kWh)	242	0.7442537	0.8061842	0.8843294	1.0577247
VIR_950	Volumetric Incentive Rate at 9.50% ($/kWh)	242	0.7638218	0.8281875	0.9084163	1.0868241
VIR_1000	Volumetric Incentive Rate at 10.00% ($/kWh)	242	0.7840072	0.8511827	0.9327162	1.1162809

Rate Class=1 Project Size Category=10 - 100 KW

Variable	Label	N	10th Pctl	25th Pctl	50th Pctl	Mean
System_Cost	System Cost ($)	70	98901.25	125590.00	202575.00	253340.60
DC_CAP	Capacity - DC (kW)	70	12.1700000	15.3900000	29.7450000	32.9164286
PUC_COST_WATT	System Cost per Watt ($/watt)	70	6.1600000	6.1600000	7.6340321	7.7569232
KWH_YEAR	Expected Annual Generation (kWh)	70	11325.40	14321.93	27680.70	30632.03
CF_YEAR	Annual Capacity Factor (%)	70	10.6232877	10.6232877	10.6232877	10.6232877
LPC_TSRF_DEG	County LPC x TSRF x Degradation	70	0.9306000	0.9306000	0.9306000	0.9306000
CMTR	Combined Marginal Tax Rate	70	0.3929000	0.3929000	0.3929000	0.3929000
VIR_600	Volumetric Incentive Rate at 6.00% ($/kWh)	70	0.5000441	0.5014459	0.6215655	0.6307044
VIR_650	Volumetric Incentive Rate at 6.50% ($/kWh)	70	0.5159090	0.5173109	0.6413310	0.6506822
VIR_700	Volumetric Incentive Rate at 7.00% ($/kWh)	70	0.5320165	0.5334184	0.6613040	0.6709654
VIR_750	Volumetric Incentive Rate at 7.50% ($/kWh)	70	0.5483616	0.5497635	0.6815487	0.6915478
VIR_800	Volumetric Incentive Rate at 8.00% ($/kWh)	70	0.5649393	0.5663411	0.7020815	0.7124231
VIR_850	Volumetric Incentive Rate at 8.50% ($/kWh)	70	0.5817444	0.5831463	0.7228961	0.7335848
VIR_900	Volumetric Incentive Rate at 9.00% ($/kWh)	70	0.5987719	0.6001737	0.7439859	0.7550265
VIR_950	Volumetric Incentive Rate at 9.50% ($/kWh)	70	0.6160165	0.6174183	0.7653447	0.7767415
VIR_1000	Volumetric Incentive Rate at 10.00% ($/kWh)	70	0.6334729	0.6348747	0.7869659	0.7987234

STAFF VIR RATES BY RATE CLASS AND PROJECT SIZE CATEGORY -- STEP7
ETO SOLAR PV DATA 2008-2009

PERIOD = 15, COUNTY CLASS = 3, TSRF = 0.90, DEGRADATION = 0.94
LOAN FEE = 0.01, INSURANCE = 0.0022, METER SERVICE = 120, TAX CALC = 1, TAX PREP = 0

The MEANS Procedure

Rate Class=2 Project Size Category=0 - 10 KW

Variable	Label	N	10th Pctl	25th Pctl	50th Pctl	Mean
System_Cost	System Cost ($)	33	21600.00	25300.00	27720.00	30615.11
DC_CAP	Capacity - DC (kW)	33	2.3100000	3.1500000	3.8000000	3.8578788
PUC_COST_WATT	System Cost per Watt ($/watt)	33	7.0000000	7.3842807	7.9591837	8.0384119
KWH_YEAR	Expected Annual Generation (kWh)	33	2345.11	3197.88	3857.76	3916.52
CF_YEAR	Annual Capacity Factor (%)	33	11.5890411	11.5890411	11.5890411	11.5890411
LPC_TSRF_DEG	County LPC x TSRF x Degradation	33	1.0152000	1.0152000	1.0152000	1.0152000
CMTR	Combined Marginal Tax Rate	33	0.3795000	0.3795000	0.3795000	0.3795000
VIR_600	Volumetric Incentive Rate at 6.00% ($/kWh)	33	0.5469521	0.5799604	0.6195403	0.6277670
VIR_650	Volumetric Incentive Rate at 6.50% ($/kWh)	33	0.5634781	0.5974859	0.6384407	0.6467446
VIR_700	Volumetric Incentive Rate at 7.00% ($/kWh)	33	0.5802567	0.6151856	0.6576300	0.6660122
VIR_750	Volumetric Incentive Rate at 7.50% ($/kWh)	33	0.5972829	0.6331465	0.6771023	0.6855641
VIR_800	Volumetric Incentive Rate at 8.00% ($/kWh)	33	0.6145513	0.6513628	0.6968518	0.7053942
VIR_850	Volumetric Incentive Rate at 8.50% ($/kWh)	33	0.6320566	0.6698292	0.7168722	0.7254964
VIR_900	Volumetric Incentive Rate at 9.00% ($/kWh)	33	0.6497936	0.6885399	0.7371574	0.7458645
VIR_950	Volumetric Incentive Rate at 9.50% ($/kWh)	33	0.6677567	0.7074891	0.7577014	0.7664923
VIR_1000	Volumetric Incentive Rate at 10.00% ($/kWh)	33	0.6859405	0.7266711	0.7784977	0.7873736

Rate Class=2 Project Size Category=10 - 100 KW

Variable	Label	N	10th Pctl	25th Pctl	50th Pctl	Mean
System_Cost	System Cost ($)	3	67500.00	67500.00	95680.00	86941.67
DC_CAP	Capacity - DC (kW)	3	10.4600000	10.4600000	10.6600000	11.0266667
PUC_COST_WATT	System Cost per Watt ($/watt)	3	6.4531549	6.4531549	8.0000000	7.8710329
KWH_YEAR	Expected Annual Generation (kWh)	3	10618.99	10618.99	10822.03	11194.27
CF_YEAR	Annual Capacity Factor (%)	3	11.5890411	11.5890411	11.5890411	11.5890411
LPC_TSRF_DEG	County LPC x TSRF x Degradation	3	1.0152000	1.0152000	1.0152000	1.0152000
CMTR	Combined Marginal Tax Rate	3	0.3929000	0.3929000	0.3929000	0.3929000
VIR_600	Volumetric Incentive Rate at 6.00% ($/kWh)	3	0.4880068	0.4880068	0.6008578	0.5922049
VIR_650	Volumetric Incentive Rate at 6.50% ($/kWh)	3	0.5032418	0.5032418	0.6197447	0.6107873
VIR_700	Volumetric Incentive Rate at 7.00% ($/kWh)	3	0.5187097	0.5187097	0.6389203	0.6296538
VIR_750	Volumetric Incentive Rate at 7.50% ($/kWh)	3	0.5344057	0.5344057	0.6583787	0.6487986
VIR_800	Volumetric Incentive Rate at 8.00% ($/kWh)	3	0.5503251	0.5503251	0.6781140	0.6682157
VIR_850	Volumetric Incentive Rate at 8.50% ($/kWh)	3	0.5664629	0.5664629	0.6981201	0.6878993
VIR_900	Volumetric Incentive Rate at 9.00% ($/kWh)	3	0.5828143	0.5828143	0.7183909	0.7078434
VIR_950	Volumetric Incentive Rate at 9.50% ($/kWh)	3	0.5993741	0.5993741	0.7389202	0.7280417
VIR_1000	Volumetric Incentive Rate at 10.00% ($/kWh)	3	0.6161373	0.6161373	0.7597017	0.7484881

STAFF VIR RATES BY RATE CLASS AND PROJECT SIZE CATEGORY -- STEP7
ETO SOLAR PV DATA 2008-2009

PERIOD = 15, COUNTY CLASS = 3, TSRF = 0.90, DEGRADATION = 0.94
LOAN FEE = 0.01, INSURANCE = 0.0022, METER SERVICE = 120, TAX CALC = 1, TAX PREP = 0

The MEANS Procedure

Rate Class=3 Project Size Category=0 - 10 KW

Variable	Label	N	10th Pctl	25th Pctl	50th Pctl	Mean
System_Cost	System Cost ($)	92	17280.00	18488.78	25919.50	31496.76
DC_CAP	Capacity - DC (kW)	92	2.0400000	2.2800000	3.0900000	3.7725000
PUC_COST_WATT	System Cost per Watt ($/watt)	92	7.0635417	7.5603447	8.0000000	8.2972844
KWH_YEAR	Expected Annual Generation (kWh)	92	2243.59	2507.54	3398.38	4149.00
CF_YEAR	Annual Capacity Factor (%)	92	12.5547945	12.5547945	12.5547945	12.5547945
LPC_TSRF_DEG	County LPC x TSRF x Degradation	92	1.0998000	1.0998000	1.0998000	1.0998000
CMTR	Combined Marginal Tax Rate	92	0.3795000	0.3795000	0.3795000	0.3795000
VIR_600	Volumetric Incentive Rate at 6.00% ($/kWh)	92	0.5048788	0.5426490	0.5859021	0.6013061
VIR_650	Volumetric Incentive Rate at 6.50% ($/kWh)	92	0.5201336	0.5592477	0.6038111	0.6193879
VIR_700	Volumetric Incentive Rate at 7.00% ($/kWh)	92	0.5356216	0.5761181	0.6219940	0.6377463
VIR_750	Volumetric Incentive Rate at 7.50% ($/kWh)	92	0.5513380	0.5932373	0.6404450	0.6563754
VIR_800	Volumetric Incentive Rate at 8.00% ($/kWh)	92	0.5673556	0.6106002	0.6591586	0.6752695
VIR_850	Volumetric Incentive Rate at 8.50% ($/kWh)	92	0.5836610	0.6282012	0.6782000	0.6944230
VIR_900	Volumetric Incentive Rate at 9.00% ($/kWh)	92	0.6001822	0.6460352	0.6976186	0.7138298
VIR_950	Volumetric Incentive Rate at 9.50% ($/kWh)	92	0.6169141	0.6640965	0.7172848	0.7334841
VIR_1000	Volumetric Incentive Rate at 10.00% ($/kWh)	92	0.6338515	0.6823797	0.7370120	0.7533798

Rate Class=3 Project Size Category=10 - 100 KW

Variable	Label	N	10th Pctl	25th Pctl	50th Pctl	Mean
System_Cost	System Cost ($)	5	81300.00	154705.00	159600.00	190196.20
DC_CAP	Capacity - DC (kW)	5	10.8000000	17.5500000	22.8000000	26.0160000
PUC_COST_WATT	System Cost per Watt ($/watt)	5	6.8959341	6.9090909	7.4726316	7.5241068
KWH_YEAR	Expected Annual Generation (kWh)	5	11877.84	19301.49	25075.44	28612.40
CF_YEAR	Annual Capacity Factor (%)	5	12.5547945	12.5547945	12.5547945	12.5547945
LPC_TSRF_DEG	County LPC x TSRF x Degradation	5	1.0998000	1.0998000	1.0998000	1.0998000
CMTR	Combined Marginal Tax Rate	5	0.3929000	0.3929000	0.3929000	0.3929000
VIR_600	Volumetric Incentive Rate at 6.00% ($/kWh)	5	0.4721838	0.4758500	0.5143396	0.5186208
VIR_650	Volumetric Incentive Rate at 6.50% ($/kWh)	5	0.4872118	0.4909067	0.5306244	0.5350177
VIR_700	Volumetric Incentive Rate at 7.00% ($/kWh)	5	0.5024695	0.5061935	0.5471581	0.5516653
VIR_750	Volumetric Incentive Rate at 7.50% ($/kWh)	5	0.5179523	0.5217058	0.5639357	0.5685585
VIR_800	Volumetric Incentive Rate at 8.00% ($/kWh)	5	0.5336554	0.5374389	0.5809520	0.5856920
VIR_850	Volumetric Incentive Rate at 8.50% ($/kWh)	5	0.5495739	0.5533878	0.5982018	0.6030607
VIR_900	Volumetric Incentive Rate at 9.00% ($/kWh)	5	0.5657031	0.5695477	0.6156798	0.6206591
VIR_950	Volumetric Incentive Rate at 9.50% ($/kWh)	5	0.5820379	0.5859137	0.6333807	0.6384819
VIR_1000	Volumetric Incentive Rate at 10.00% ($/kWh)	5	0.5985734	0.6024808	0.6512991	0.6565237

STAFF VIR RATES BY RATE CLASS AND PROJECT SIZE CATEGORY -- STEP7
ETO SOLAR PV DATA 2008-2009

PERIOD = 15, COUNTY CLASS = 3, TSRF = 0.90, DEGRADATION = 0.94
LOAN FEE = 0.01, INSURANCE = 0.0022, METER SERVICE = 120, TAX CALC = 1, TAX PREP = 0

The MEANS Procedure

Rate Class=4 Project Size Category=0 - 10 KW

Variable	Label	N	10th Pctl	25th Pctl	50th Pctl	Mean
System_Cost	System Cost ($)	55	13700.00	14050.00	18000.00	24797.19
DC_CAP	Capacity - DC (kW)	55	2.0000000	2.0000000	2.1000000	3.1303636
PUC_COST_WATT	System Cost per Watt ($/watt)	55	6.5238095	6.9900000	7.5000000	7.8097056
KWH_YEAR	Expected Annual Generation (kWh)	55	2368.80	2368.80	2487.24	3707.60
CF_YEAR	Annual Capacity Factor (%)	55	13.5205479	13.5205479	13.5205479	13.5205479
LPC_TSRF_DEG	County LPC x TSRF x Degradation	55	1.1844000	1.1844000	1.1844000	1.1844000
CMTR	Combined Marginal Tax Rate	55	0.3795000	0.3795000	0.3795000	0.3795000
VIR_600	Volumetric Incentive Rate at 6.00% ($/kWh)	55	0.4635859	0.4929826	0.5250422	0.5357367
VIR_650	Volumetric Incentive Rate at 6.50% ($/kWh)	55	0.4772452	0.5081596	0.5402191	0.5515404
VIR_700	Volumetric Incentive Rate at 7.00% ($/kWh)	55	0.4911133	0.5235685	0.5556281	0.5675856
VIR_750	Volumetric Incentive Rate at 7.50% ($/kWh)	55	0.5051859	0.5392048	0.5712643	0.5838675
VIR_800	Volumetric Incentive Rate at 8.00% ($/kWh)	55	0.5191746	0.5546062	0.5871231	0.6003812
VIR_850	Volumetric Incentive Rate at 8.50% ($/kWh)	55	0.5331585	0.5695893	0.6031994	0.6171214
VIR_900	Volumetric Incentive Rate at 9.00% ($/kWh)	55	0.5473274	0.5847707	0.6194885	0.6340830
VIR_950	Volumetric Incentive Rate at 9.50% ($/kWh)	55	0.5616769	0.6001457	0.6359852	0.6512610
VIR_1000	Volumetric Incentive Rate at 10.00% ($/kWh)	55	0.5765403	0.6157095	0.6526846	0.6686500

Rate Class=4 Project Size Category=10 - 100 KW

Variable	Label	N	10th Pctl	25th Pctl	50th Pctl	Mean
System_Cost	System Cost ($)	5	148000.00	198000.00	304100.00	279820.00
DC_CAP	Capacity - DC (kW)	5	18.3600000	21.6000000	35.1000000	31.7880000
PUC_COST_WATT	System Cost per Watt ($/watt)	5	7.9038282	8.0610022	8.6638177	8.7590629
KWH_YEAR	Expected Annual Generation (kWh)	5	21745.58	25583.04	41572.44	37649.71
CF_YEAR	Annual Capacity Factor (%)	5	13.5205479	13.5205479	13.5205479	13.5205479
LPC_TSRF_DEG	County LPC x TSRF x Degradation	5	1.1844000	1.1844000	1.1844000	1.1844000
CMTR	Combined Marginal Tax Rate	5	0.3929000	0.3929000	0.3929000	0.3929000
VIR_600	Volumetric Incentive Rate at 6.00% ($/kWh)	5	0.5028252	0.5159306	0.5514682	0.5581984
VIR_650	Volumetric Incentive Rate at 6.50% ($/kWh)	5	0.5188193	0.5322428	0.5690003	0.5759231
VIR_700	Volumetric Incentive Rate at 7.00% ($/kWh)	5	0.5350579	0.5488043	0.5868003	0.5939189
VIR_750	Volumetric Incentive Rate at 7.50% ($/kWh)	5	0.5515361	0.5656102	0.6048629	0.6121801
VIR_800	Volumetric Incentive Rate at 8.00% ($/kWh)	5	0.5682487	0.5826551	0.6231826	0.6307011
VIR_850	Volumetric Incentive Rate at 8.50% ($/kWh)	5	0.5851907	0.5999340	0.6417536	0.6494763
VIR_900	Volumetric Incentive Rate at 9.00% ($/kWh)	5	0.6023568	0.6174415	0.6605703	0.6684998
VIR_950	Volumetric Incentive Rate at 9.50% ($/kWh)	5	0.6197418	0.6351721	0.6796269	0.6877659
VIR_1000	Volumetric Incentive Rate at 10.00% ($/kWh)	5	0.6373403	0.6531207	0.6989176	0.7072687

STAFF VIR RATES BY RATE CLASS AND PROJECT SIZE CATEGORY -- STEP7
ETO SOLAR PV DATA 2008-2009

PERIOD = 15, COUNTY CLASS = 3, TSRF = 0.90, DEGRADATION = 0.94
LOAN FEE = 0.01, INSURANCE = 0.0022, METER SERVICE = 120, TAX CALC = 1, TAX PREP = 0

The MEANS Procedure

Project Size Category=0 - 10 KW

Variable	Label	N	10th Pctl	25th Pctl	50th Pctl	Mean
System_Cost	System Cost ($)	422	15226.50	19350.00	24946.58	29156.07
DC_CAP	Capacity - DC (kW)	422	2.0000000	2.1600000	3.0000000	3.4284123
PUC_COST_WATT	System Cost per Watt ($/watt)	422	7.0000000	7.6463675	8.2871558	9.4162638
KWH_YEAR	Expected Annual Generation (kWh)	422	1879.81	2254.59	2791.80	3458.71
CF_YEAR	Annual Capacity Factor (%)	422	10.6232877	10.6232877	10.6232877	11.4975005
LPC_TSRF_DEG	County LPC x TSRF x Degradation	422	0.9306000	0.9306000	0.9306000	1.0071810
VIR_600	Volumetric Incentive Rate at 6.00% ($/kWh)	422	0.5105889	0.5839821	0.6688386	0.7610300
VIR_650	Volumetric Incentive Rate at 6.50% ($/kWh)	422	0.5264538	0.6017301	0.6891529	0.7838680
VIR_700	Volumetric Incentive Rate at 7.00% ($/kWh)	422	0.5425613	0.6192510	0.7097778	0.8070552
VIR_750	Volumetric Incentive Rate at 7.50% ($/kWh)	422	0.5589064	0.6372987	0.7307068	0.8305843
VIR_800	Volumetric Incentive Rate at 8.00% ($/kWh)	422	0.5754841	0.6556032	0.7519337	0.8544483
VIR_850	Volumetric Incentive Rate at 8.50% ($/kWh)	422	0.5922892	0.6741589	0.7733030	0.8786398
VIR_900	Volumetric Incentive Rate at 9.00% ($/kWh)	422	0.6093167	0.6929601	0.7945119	0.9031512
VIR_950	Volumetric Incentive Rate at 9.50% ($/kWh)	422	0.6265613	0.7120010	0.8159912	0.9279753
VIR_1000	Volumetric Incentive Rate at 10.00% ($/kWh)	422	0.6440177	0.7312758	0.8378933	0.9531042

Project Size Category=10 - 100 KW

Variable	Label	N	10th Pctl	25th Pctl	50th Pctl	Mean
System_Cost	System Cost ($)	83	95772.00	123996.00	193116.00	245117.44
DC_CAP	Capacity - DC (kW)	83	11.5500000	15.1200000	28.5000000	31.6415663
PUC_COST_WATT	System Cost per Watt ($/watt)	83	6.1600000	6.8959341	7.6869919	7.8073925
KWH_YEAR	Expected Annual Generation (kWh)	83	11260.26	14070.67	26522.10	30230.55
CF_YEAR	Annual Capacity Factor (%)	83	10.6232877	10.6232877	10.6232877	10.9490840
LPC_TSRF_DEG	County LPC x TSRF x Degradation	83	0.9306000	0.9306000	0.9306000	0.9591398
VIR_600	Volumetric Incentive Rate at 6.00% ($/kWh)	83	0.4998991	0.5014459	0.6179163	0.6181930
VIR_650	Volumetric Incentive Rate at 6.50% ($/kWh)	83	0.5157640	0.5173109	0.6374126	0.6377689
VIR_700	Volumetric Incentive Rate at 7.00% ($/kWh)	83	0.5318715	0.5334184	0.6572070	0.6576441
VIR_750	Volumetric Incentive Rate at 7.50% ($/kWh)	83	0.5482166	0.5497635	0.6772933	0.6778125
VIR_800	Volumetric Incentive Rate at 8.00% ($/kWh)	83	0.5647943	0.5663411	0.6976654	0.6982678
VIR_850	Volumetric Incentive Rate at 8.50% ($/kWh)	83	0.5815994	0.5831463	0.7183171	0.7190038
VIR_900	Volumetric Incentive Rate at 9.00% ($/kWh)	83	0.5986269	0.6001737	0.7392420	0.7400142
VIR_950	Volumetric Incentive Rate at 9.50% ($/kWh)	83	0.6158715	0.6174183	0.7604337	0.7612924
VIR_1000	Volumetric Incentive Rate at 10.00% ($/kWh)	83	0.6333279	0.6348747	0.7818857	0.7828321

STAFF VIR RATES BY RATE CLASS AND PROJECT SIZE CATEGORY -- STEP8
ETO SOLAR PV DATA 2008-2009

PERIOD = 15, COUNTY CLASS = 3, TSRF = 0.90, DEGRADATION = 0.94
LOAN FEE = 0.01, INSURANCE = 0.0022, METER SERVICE = 120, TAX CALC = 1, TAX PREP = 100

The MEANS Procedure

Rate Class=1 Project Size Category=0 - 10 KW

Variable	Label	N	10th Pctl	25th Pctl	50th Pctl	Mean
System_Cost	System Cost ($)	242	16743.00	19898.00	24891.50	29057.92
DC_CAP	Capacity - DC (kW)	242	2.0000000	2.2400000	2.8650000	3.3067769
PUC_COST_WATT	System Cost per Watt ($/watt)	242	7.2372928	7.9226765	8.6877381	10.3946767
KWH_YEAR	Expected Annual Generation (kWh)	242	1861.20	2084.54	2666.17	3077.29
CF_YEAR	Annual Capacity Factor (%)	242	10.6232877	10.6232877	10.6232877	10.6232877
LPC_TSRF_DEG	County LPC x TSRF x Degradation	242	0.9306000	0.9306000	0.9306000	0.9306000
CMTR	Combined Marginal Tax Rate	242	0.3795000	0.3795000	0.3795000	0.3795000
VIR_600	Volumetric Incentive Rate at 6.00% ($/kWh)	242	0.6647705	0.7059080	0.7895362	0.9347707
VIR_650	Volumetric Incentive Rate at 6.50% ($/kWh)	242	0.6836173	0.7263217	0.8120544	0.9615420
VIR_700	Volumetric Incentive Rate at 7.00% ($/kWh)	242	0.7027522	0.7470473	0.8351097	0.9887225
VIR_750	Volumetric Incentive Rate at 7.50% ($/kWh)	242	0.7221693	0.7681974	0.8580397	1.0163040
VIR_800	Volumetric Incentive Rate at 8.00% ($/kWh)	242	0.7418628	0.7906239	0.8809368	1.0442780
VIR_850	Volumetric Incentive Rate at 8.50% ($/kWh)	242	0.7618265	0.8130833	0.9038069	1.0726358
VIR_900	Volumetric Incentive Rate at 9.00% ($/kWh)	242	0.7820542	0.8353330	0.9269796	1.1013687
VIR_950	Volumetric Incentive Rate at 9.50% ($/kWh)	242	0.8025399	0.8578663	0.9504478	1.1304680
VIR_1000	Volumetric Incentive Rate at 10.00% ($/kWh)	242	0.8232773	0.8800002	0.9743878	1.1599248

Rate Class=1 Project Size Category=10 - 100 KW

Variable	Label	N	10th Pctl	25th Pctl	50th Pctl	Mean
System_Cost	System Cost ($)	70	98901.25	125590.00	202575.00	253340.60
DC_CAP	Capacity - DC (kW)	70	12.1700000	15.3900000	29.7450000	32.9164286
PUC_COST_WATT	System Cost per Watt ($/watt)	70	6.1600000	6.1600000	7.6340321	7.7569232
KWH_YEAR	Expected Annual Generation (kWh)	70	11325.40	14321.93	27680.70	30632.03
CF_YEAR	Annual Capacity Factor (%)	70	10.6232877	10.6232877	10.6232877	10.6232877
LPC_TSRF_DEG	County LPC x TSRF x Degradation	70	0.9306000	0.9306000	0.9306000	0.9306000
CMTR	Combined Marginal Tax Rate	70	0.3929000	0.3929000	0.3929000	0.3929000
VIR_600	Volumetric Incentive Rate at 6.00% ($/kWh)	70	0.5030653	0.5056353	0.6255574	0.6353658
VIR_650	Volumetric Incentive Rate at 6.50% ($/kWh)	70	0.5189302	0.5215002	0.6452265	0.6553436
VIR_700	Volumetric Incentive Rate at 7.00% ($/kWh)	70	0.5350377	0.5376077	0.6651964	0.6756268
VIR_750	Volumetric Incentive Rate at 7.50% ($/kWh)	70	0.5513828	0.5539528	0.6854608	0.6962092
VIR_800	Volumetric Incentive Rate at 8.00% ($/kWh)	70	0.5679605	0.5705305	0.7060135	0.7170845
VIR_850	Volumetric Incentive Rate at 8.50% ($/kWh)	70	0.5847656	0.5873357	0.7268483	0.7382462
VIR_900	Volumetric Incentive Rate at 9.00% ($/kWh)	70	0.6017931	0.6043631	0.7479587	0.7596879
VIR_950	Volumetric Incentive Rate at 9.50% ($/kWh)	70	0.6190377	0.6216077	0.7693383	0.7814030
VIR_1000	Volumetric Incentive Rate at 10.00% ($/kWh)	70	0.6364941	0.6390641	0.7909805	0.8033848

STAFF VIR RATES BY RATE CLASS AND PROJECT SIZE CATEGORY -- STEP8
ETO SOLAR PV DATA 2008-2009

PERIOD = 15, COUNTY CLASS = 3, TSRF = 0.90, DEGRADATION = 0.94
LOAN FEE = 0.01, INSURANCE = 0.0022, METER SERVICE = 120, TAX CALC = 1, TAX PREP = 100

The MEANS Procedure

Rate Class=2 Project Size Category=0 - 10 KW

Variable	Label	N	10th Pctl	25th Pctl	50th Pctl	Mean
System_Cost	System Cost ($)	33	21600.00	25300.00	27720.00	30615.11
DC_CAP	Capacity - DC (kW)	33	2.3100000	3.1500000	3.8000000	3.8578788
PUC_COST_WATT	System Cost per Watt ($/watt)	33	7.0000000	7.3842807	7.9591837	8.0384119
KWH_YEAR	Expected Annual Generation (kWh)	33	2345.11	3197.88	3857.76	3916.52
CF_YEAR	Annual Capacity Factor (%)	33	11.5890411	11.5890411	11.5890411	11.5890411
LPC_TSRF_DEG	County LPC x TSRF x Degradation	33	1.0152000	1.0152000	1.0152000	1.0152000
CMTR	Combined Marginal Tax Rate	33	0.3795000	0.3795000	0.3795000	0.3795000
VIR_600	Volumetric Incentive Rate at 6.00% ($/kWh)	33	0.5718265	0.5983675	0.6437232	0.6560257
VIR_650	Volumetric Incentive Rate at 6.50% ($/kWh)	33	0.5883525	0.6164913	0.6621583	0.6750032
VIR_700	Volumetric Incentive Rate at 7.00% ($/kWh)	33	0.6051312	0.6348921	0.6810830	0.6942709
VIR_750	Volumetric Incentive Rate at 7.50% ($/kWh)	33	0.6221573	0.6535644	0.7005554	0.7138227
VIR_800	Volumetric Incentive Rate at 8.00% ($/kWh)	33	0.6394257	0.6725023	0.7203048	0.7336528
VIR_850	Volumetric Incentive Rate at 8.50% ($/kWh)	33	0.6569311	0.6917001	0.7403252	0.7537550
VIR_900	Volumetric Incentive Rate at 9.00% ($/kWh)	33	0.6746680	0.7111519	0.7606105	0.7741231
VIR_950	Volumetric Incentive Rate at 9.50% ($/kWh)	33	0.6926311	0.7308517	0.7811544	0.7947510
VIR_1000	Volumetric Incentive Rate at 10.00% ($/kWh)	33	0.7108149	0.7504780	0.8019507	0.8156322

Rate Class=2 Project Size Category=10 - 100 KW

Variable	Label	N	10th Pctl	25th Pctl	50th Pctl	Mean
System_Cost	System Cost ($)	3	67500.00	67500.00	95680.00	86941.67
DC_CAP	Capacity - DC (kW)	3	10.4600000	10.4600000	10.6600000	11.0266667
PUC_COST_WATT	System Cost per Watt ($/watt)	3	6.4531549	6.4531549	8.0000000	7.8710329
KWH_YEAR	Expected Annual Generation (kWh)	3	10618.99	10618.99	10822.03	11194.27
CF_YEAR	Annual Capacity Factor (%)	3	11.5890411	11.5890411	11.5890411	11.5890411
LPC_TSRF_DEG	County LPC x TSRF x Degradation	3	1.0152000	1.0152000	1.0152000	1.0152000
CMTR	Combined Marginal Tax Rate	3	0.3929000	0.3929000	0.3929000	0.3929000
VIR_600	Volumetric Incentive Rate at 6.00% ($/kWh)	3	0.4974239	0.4974239	0.6090938	0.6011695
VIR_650	Volumetric Incentive Rate at 6.50% ($/kWh)	3	0.5126589	0.5126589	0.6279807	0.6197518
VIR_700	Volumetric Incentive Rate at 7.00% ($/kWh)	3	0.5281268	0.5281268	0.6471563	0.6386183
VIR_750	Volumetric Incentive Rate at 7.50% ($/kWh)	3	0.5438228	0.5438228	0.6666147	0.6577631
VIR_800	Volumetric Incentive Rate at 8.00% ($/kWh)	3	0.5597422	0.5597422	0.6863500	0.6771802
VIR_850	Volumetric Incentive Rate at 8.50% ($/kWh)	3	0.5758800	0.5758800	0.7063562	0.6968638
VIR_900	Volumetric Incentive Rate at 9.00% ($/kWh)	3	0.5922314	0.5922314	0.7266270	0.7168079
VIR_950	Volumetric Incentive Rate at 9.50% ($/kWh)	3	0.6087912	0.6087912	0.7471562	0.7370062
VIR_1000	Volumetric Incentive Rate at 10.00% ($/kWh)	3	0.6255544	0.6255544	0.7679377	0.7574526

STAFF VIR RATES BY RATE CLASS AND PROJECT SIZE CATEGORY -- STEP8
ETO SOLAR PV DATA 2008-2009

PERIOD = 15, COUNTY CLASS = 3, TSRF = 0.90, DEGRADATION = 0.94
LOAN FEE = 0.01, INSURANCE = 0.0022, METER SERVICE = 120, TAX CALC = 1, TAX PREP = 100

The MEANS Procedure

Rate Class=3 Project Size Category=0 - 10 KW

Variable	Label	N	10th Pctl	25th Pctl	50th Pctl	Mean
System_Cost	System Cost ($)	92	17280.00	18488.78	25919.50	31496.76
DC_CAP	Capacity - DC (kW)	92	2.0400000	2.2800000	3.0900000	3.7725000
PUC_COST_WATT	System Cost per Watt ($/watt)	92	7.0635417	7.5603447	8.0000000	8.2972844
KWH_YEAR	Expected Annual Generation (kWh)	92	2243.59	2507.54	3398.38	4149.00
CF_YEAR	Annual Capacity Factor (%)	92	12.5547945	12.5547945	12.5547945	12.5547945
LPC_TSRF_DEG	County LPC x TSRF x Degradation	92	1.0998000	1.0998000	1.0998000	1.0998000
CMTR	Combined Marginal Tax Rate	92	0.3795000	0.3795000	0.3795000	0.3795000
VIR_600	Volumetric Incentive Rate at 6.00% ($/kWh)	92	0.5223974	0.5643708	0.6164232	0.6308229
VIR_650	Volumetric Incentive Rate at 6.50% ($/kWh)	92	0.5382624	0.5812691	0.6333751	0.6489048
VIR_700	Volumetric Incentive Rate at 7.00% ($/kWh)	92	0.5543545	0.5984257	0.6506533	0.6672631
VIR_750	Volumetric Incentive Rate at 7.50% ($/kWh)	92	0.5702136	0.6158354	0.6686479	0.6858922
VIR_800	Volumetric Incentive Rate at 8.00% ($/kWh)	92	0.5862984	0.6334928	0.6868986	0.7047864
VIR_850	Volumetric Incentive Rate at 8.50% ($/kWh)	92	0.6027881	0.6513925	0.7053998	0.7239398
VIR_900	Volumetric Incentive Rate at 9.00% ($/kWh)	92	0.6193614	0.6693529	0.7241457	0.7433467
VIR_950	Volumetric Incentive Rate at 9.50% ($/kWh)	92	0.6358569	0.6871751	0.7431307	0.7630009
VIR_1000	Volumetric Incentive Rate at 10.00% ($/kWh)	92	0.6527943	0.7052162	0.7623489	0.7828967

Rate Class=3 Project Size Category=10 - 100 KW

Variable	Label	N	10th Pctl	25th Pctl	50th Pctl	Mean
System_Cost	System Cost ($)	5	81300.00	154705.00	159600.00	190196.20
DC_CAP	Capacity - DC (kW)	5	10.8000000	17.5500000	22.8000000	26.0160000
PUC_COST_WATT	System Cost per Watt ($/watt)	5	6.8959341	6.9090909	7.4726316	7.5241068
KWH_YEAR	Expected Annual Generation (kWh)	5	11877.84	19301.49	25075.44	28612.40
CF_YEAR	Annual Capacity Factor (%)	5	12.5547945	12.5547945	12.5547945	12.5547945
LPC_TSRF_DEG	County LPC x TSRF x Degradation	5	1.0998000	1.0998000	1.0998000	1.0998000
CMTR	Combined Marginal Tax Rate	5	0.3929000	0.3929000	0.3929000	0.3929000
VIR_600	Volumetric Incentive Rate at 6.00% ($/kWh)	5	0.4738124	0.4797862	0.5183276	0.5232513
VIR_650	Volumetric Incentive Rate at 6.50% ($/kWh)	5	0.4888404	0.4948428	0.5346124	0.5396483
VIR_700	Volumetric Incentive Rate at 7.00% ($/kWh)	5	0.5040981	0.5101297	0.5511461	0.5562959
VIR_750	Volumetric Incentive Rate at 7.50% ($/kWh)	5	0.5195809	0.5256420	0.5679237	0.5731890
VIR_800	Volumetric Incentive Rate at 8.00% ($/kWh)	5	0.5352840	0.5413750	0.5849400	0.5903226
VIR_850	Volumetric Incentive Rate at 8.50% ($/kWh)	5	0.5512026	0.5573240	0.6021898	0.6076912
VIR_900	Volumetric Incentive Rate at 9.00% ($/kWh)	5	0.5673317	0.5734839	0.6196678	0.6252896
VIR_950	Volumetric Incentive Rate at 9.50% ($/kWh)	5	0.5836665	0.5898499	0.6373687	0.6431124
VIR_1000	Volumetric Incentive Rate at 10.00% ($/kWh)	5	0.6002020	0.6064169	0.6552870	0.6611542

STAFF VIR RATES BY RATE CLASS AND PROJECT SIZE CATEGORY -- STEP8
ETO SOLAR PV DATA 2008-2009

PERIOD = 15, COUNTY CLASS = 3, TSRF = 0.90, DEGRADATION = 0.94
LOAN FEE = 0.01, INSURANCE = 0.0022, METER SERVICE = 120, TAX CALC = 1, TAX PREP = 100

The MEANS Procedure

Rate Class=4 Project Size Category=0 - 10 KW

Variable	Label	N	10th Pctl	25th Pctl	50th Pctl	Mean
System_Cost	System Cost ($)	55	13700.00	14050.00	18000.00	24797.19
DC_CAP	Capacity - DC (kW)	55	2.0000000	2.0000000	2.1000000	3.1303636
PUC_COST_WATT	System Cost per Watt ($/watt)	55	6.5238095	6.9900000	7.5000000	7.8097056
KWH_YEAR	Expected Annual Generation (kWh)	55	2368.80	2368.80	2487.24	3707.60
CF_YEAR	Annual Capacity Factor (%)	55	13.5205479	13.5205479	13.5205479	13.5205479
LPC_TSRF_DEG	County LPC x TSRF x Degradation	55	1.1844000	1.1844000	1.1844000	1.1844000
CMTR	Combined Marginal Tax Rate	55	0.3795000	0.3795000	0.3795000	0.3795000
VIR_600	Volumetric Incentive Rate at 6.00% ($/kWh)	55	0.4997235	0.5206746	0.5554228	0.5686829
VIR_650	Volumetric Incentive Rate at 6.50% ($/kWh)	55	0.5127324	0.5355480	0.5715107	0.5844865
VIR_700	Volumetric Incentive Rate at 7.00% ($/kWh)	55	0.5259400	0.5506488	0.5878445	0.6005318
VIR_750	Volumetric Incentive Rate at 7.50% ($/kWh)	55	0.5393425	0.5659723	0.6044192	0.6168137
VIR_800	Volumetric Incentive Rate at 8.00% ($/kWh)	55	0.5529357	0.5815139	0.6212297	0.6333273
VIR_850	Volumetric Incentive Rate at 8.50% ($/kWh)	55	0.5667155	0.5972687	0.6382710	0.6500675
VIR_900	Volumetric Incentive Rate at 9.00% ($/kWh)	55	0.5806775	0.6132320	0.6555377	0.6670292
VIR_950	Volumetric Incentive Rate at 9.50% ($/kWh)	55	0.5948175	0.6293988	0.6720323	0.6842072
VIR_1000	Volumetric Incentive Rate at 10.00% ($/kWh)	55	0.6091313	0.6457642	0.6885652	0.7015961

Rate Class=4 Project Size Category=10 - 100 KW

Variable	Label	N	10th Pctl	25th Pctl	50th Pctl	Mean
System_Cost	System Cost ($)	5	148000.00	198000.00	304100.00	279820.00
DC_CAP	Capacity - DC (kW)	5	18.3600000	21.6000000	35.1000000	31.7880000
PUC_COST_WATT	System Cost per Watt ($/watt)	5	7.9038282	8.0610022	8.6638177	8.7590629
KWH_YEAR	Expected Annual Generation (kWh)	5	21745.58	25583.04	41572.44	37649.71
CF_YEAR	Annual Capacity Factor (%)	5	13.5205479	13.5205479	13.5205479	13.5205479
LPC_TSRF_DEG	County LPC x TSRF x Degradation	5	1.1844000	1.1844000	1.1844000	1.1844000
CMTR	Combined Marginal Tax Rate	5	0.3929000	0.3929000	0.3929000	0.3929000
VIR_600	Volumetric Incentive Rate at 6.00% ($/kWh)	5	0.5047960	0.5205292	0.5538737	0.5611866
VIR_650	Volumetric Incentive Rate at 6.50% ($/kWh)	5	0.5207902	0.5368414	0.5714057	0.5789114
VIR_700	Volumetric Incentive Rate at 7.00% ($/kWh)	5	0.5370288	0.5534030	0.5892058	0.5969071
VIR_750	Volumetric Incentive Rate at 7.50% ($/kWh)	5	0.5535069	0.5702088	0.6072684	0.6151683
VIR_800	Volumetric Incentive Rate at 8.00% ($/kWh)	5	0.5702196	0.5872538	0.6255880	0.6336893
VIR_850	Volumetric Incentive Rate at 8.50% ($/kWh)	5	0.5871615	0.6045326	0.6441590	0.6524645
VIR_900	Volumetric Incentive Rate at 9.00% ($/kWh)	5	0.6043276	0.6220401	0.6629757	0.6714880
VIR_950	Volumetric Incentive Rate at 9.50% ($/kWh)	5	0.6217126	0.6397708	0.6820323	0.6907541
VIR_1000	Volumetric Incentive Rate at 10.00% ($/kWh)	5	0.6393112	0.6577193	0.7013231	0.7102569

STAFF VIR RATES BY RATE CLASS AND PROJECT SIZE CATEGORY -- STEP8
ETO SOLAR PV DATA 2008-2009

PERIOD = 15, COUNTY CLASS = 3, TSRF = 0.90, DEGRADATION = 0.94
LOAN FEE = 0.01, INSURANCE = 0.0022, METER SERVICE = 120, TAX CALC = 1, TAX PREP = 100

The MEANS Procedure

Project Size Category=0 - 10 KW

Variable	Label	N	10th Pctl	25th Pctl	50th Pctl	Mean
System_Cost	System Cost ($)	422	15226.50	19350.00	24946.58	29156.07
DC_CAP	Capacity - DC (kW)	422	2.0000000	2.1600000	3.0000000	3.4284123
PUC_COST_WATT	System Cost per Watt ($/watt)	422	7.0000000	7.6463675	8.2871558	9.4162638
KWH_YEAR	Expected Annual Generation (kWh)	422	1879.81	2254.59	2791.80	3458.71
CF_YEAR	Annual Capacity Factor (%)	422	10.6232877	10.6232877	10.6232877	11.4975005
LPC_TSRF_DEG	County LPC x TSRF x Degradation	422	0.9306000	0.9306000	0.9306000	1.0071810
VIR_600	Volumetric Incentive Rate at 6.00% ($/kWh)	422	0.5436838	0.6108308	0.7001906	0.7989967
VIR_650	Volumetric Incentive Rate at 6.50% ($/kWh)	422	0.5596573	0.6275254	0.7197780	0.8218347
VIR_700	Volumetric Incentive Rate at 7.00% ($/kWh)	422	0.5754013	0.6451157	0.7404577	0.8450219
VIR_750	Volumetric Incentive Rate at 7.50% ($/kWh)	422	0.5902349	0.6636225	0.7610790	0.8685511
VIR_800	Volumetric Incentive Rate at 8.00% ($/kWh)	422	0.6052795	0.6824090	0.7819787	0.8924151
VIR_850	Volumetric Incentive Rate at 8.50% ($/kWh)	422	0.6205306	0.7005645	0.8037025	0.9166065
VIR_900	Volumetric Incentive Rate at 9.00% ($/kWh)	422	0.6359835	0.7190550	0.8256376	0.9411180
VIR_950	Volumetric Incentive Rate at 9.50% ($/kWh)	422	0.6516334	0.7374129	0.8472260	0.9659420
VIR_1000	Volumetric Incentive Rate at 10.00% ($/kWh)	422	0.6674755	0.7568214	0.8701773	0.9910710

Project Size Category=10 - 100 KW

Variable	Label	N	10th Pctl	25th Pctl	50th Pctl	Mean
System_Cost	System Cost ($)	83	95772.00	123996.00	193116.00	245117.44
DC_CAP	Capacity - DC (kW)	83	11.5500000	15.1200000	28.5000000	31.6415663
PUC_COST_WATT	System Cost per Watt ($/watt)	83	6.1600000	6.8959341	7.6869919	7.8073925
KWH_YEAR	Expected Annual Generation (kWh)	83	11260.26	14070.67	26522.10	30230.55
CF_YEAR	Annual Capacity Factor (%)	83	10.6232877	10.6232877	10.6232877	10.9490840
LPC_TSRF_DEG	County LPC x TSRF x Degradation	83	0.9306000	0.9306000	0.9306000	0.9591398
VIR_600	Volumetric Incentive Rate at 6.00% ($/kWh)	83	0.5027994	0.5047960	0.6209091	0.6229073
VIR_650	Volumetric Incentive Rate at 6.50% ($/kWh)	83	0.5186644	0.5207902	0.6405577	0.6424832
VIR_700	Volumetric Incentive Rate at 7.00% ($/kWh)	83	0.5347719	0.5370288	0.6605067	0.6623584
VIR_750	Volumetric Incentive Rate at 7.50% ($/kWh)	83	0.5511169	0.5535069	0.6807499	0.6825268
VIR_800	Volumetric Incentive Rate at 8.00% ($/kWh)	83	0.5676946	0.5702196	0.7012812	0.7029821
VIR_850	Volumetric Incentive Rate at 8.50% ($/kWh)	83	0.5844998	0.5871615	0.7220942	0.7237182
VIR_900	Volumetric Incentive Rate at 9.00% ($/kWh)	83	0.6015272	0.6043276	0.7431826	0.7447285
VIR_950	Volumetric Incentive Rate at 9.50% ($/kWh)	83	0.6187718	0.6216077	0.7645398	0.7660068
VIR_1000	Volumetric Incentive Rate at 10.00% ($/kWh)	83	0.6362282	0.6390641	0.7861594	0.7875464

```
*------------------------------------------*;
*--- UM1452 IMPORT ETO PV DATA 02-10-2010  ---*;
*------------------------------------------*;

LIBNAME ETO "H:\UM 1452\ETO SOLAR PV DATA CONFINDENTIAL.xls";

LIBNAME LPC "H:\UM 1452\CITY_LPC_XWALK.xls";

*  LIBNAME ETO CLEAR;
*  LIBNAME LPC CLEAR;


*---------------------------------*;

%LET STEP = STEP8;
%PUT THE RUN STEP IS: &STEP;

%LET FILE = "H:\UM 1452\FINAL SOLAR PV VIR &STEP 02-10-2010.PDF";
%PUT THE FILE NAME IS: &FILE;

%LET PERIOD = 15;
%PUT THE NUMBER OF PERIODS IS: &PERIOD;

*%LET TSRF = 1.00;
%LET TSRF = 0.90;
*%LET TSRF = 0.89;
%PUT THE TOTAL SOLAR RESOURCE FRACTION IS: &TSRF;

*%LET DEGRADE = 1.00;
%LET DEGRADE = 0.94;
%PUT THE ANNUAL SOLAR RESOURCE DEGRADATION FACTOR IS: &DEGRADE;

*%LET RC = 2;
%LET RC = 3;
%PUT THE RATE CLASS CLASSIFICATION IS: &RC;

*%LET LFR = 0.00;
%LET LFR = 0.01;
%PUT THE LOAN FEE RATE IS: &LFR;

*%LET INSR = 0.0000;
%LET INSR = 0.0022;
%PUT THE INSURANCE RATE IS: &INSR;

*%LET MS = 0;
%LET MS = 120;
%PUT THE ANNUAL METER SERVICE CHARGE IS: $&MS;

*%LET TCALC = 0;
%LET TCALC = 1;
%PUT THE TAX CALCULATION TRIGGER IS: &TCALC;

*%LET TP = 0;
%LET TP = 100;
```

```
%PUT THE ANNUAL TAX PREPARATION FEE IS: $&TP;


*-----------------------------------*;
*--------- IMPORT ETO DATA ----------*;
*-----------------------------------*;

DATA ETO;
 SET ETO.'SHEET1$'N;
RUN;


*PROC CONTENTS DATA=ETO ORDER=VARNUM;
*TITLE 'ETO SOLAR PV DATASET';
*RUN;


DATA ETO2;
 SET ETO;

 *INSTALLED_COST = INPUT(SYSTEM_COST,8.2);

 COST_WATT = INPUT(__W,8.2);
 COST_WATT_R = ROUND(COST_WATT,.1);

 DC_CAP = INPUT(DC_CAPACITY__FT_,8.2);
 DC_CAP_R = ROUND(DC_CAP,1);

 PUC_COST_KW = SYSTEM_COST/DC_CAP;
 PUC_COST_WATT = PUC_COST_KW/1000;
 PUC_COST_WATT_R = ROUND(PUC_COST_WATT,.1);

 COMP_YEAR = YEAR(COMPLETED_DATE);

 *--- SYSTEM SIZE CATEGORIES ---*;

  IF DC_CAP LE 30 THEN CAP_CAT = 1;
 ELSE IF 30 LT DC_CAP LE 100 THEN CAP_CAT =2;
 ELSE IF 100 LT DC_CAP THEN CAP_CAT = 3;

 IF DC_CAP LE 10 THEN CAP_CAT2 = 1;
 ELSE IF 10 LT DC_CAP LE 30 THEN CAP_CAT2 =2;
 ELSE IF 30 LT DC_CAP LE 100 THEN CAP_CAT2 =3;
 ELSE IF 100 LT DC_CAP THEN CAP_CAT2 = 4;

 IF DC_CAP LE 10 THEN CAP_CAT3 = 1;
 ELSE IF 10 LT DC_CAP LE 100 THEN CAP_CAT3 =2;
 ELSE IF 100 LT DC_CAP THEN CAP_CAT3 = 3;

 IF DC_CAP LE 10 THEN CAP_CAT4 = 1;
 ELSE IF 10 LT DC_CAP THEN CAP_CAT4 = 2;


 *--- CITY TO COUNTY PREP ---*;
```

```
 IF CITY = 'Corvalis' THEN CITY = 'Corvallis';
 IF CITY = 'Roseberg' THEN CITY = 'Roseburg';
 CITY_X = CITY;
RUN;


PROC FORMAT;
 VALUE CAP_CAT_1_FMT 1 = '   0 - 30 KW'
                     2 = '  30 - 100 KW'
                     3 = ' 100+      KW'
                     . = ' Missing'
                 OTHER = ' Miscode';


 VALUE CAP_CAT_2_FMT 1 = '   0 - 10 KW'
                     2 = '  10 - 30 KW'
                     3 = '  30 - 100 KW'
                     4 = ' 100+ KW'
                     . = ' Missing'
                 OTHER = ' Miscode';

 VALUE CAP_CAT_3_FMT 1 = '   0 - 10 KW'
                     2 = '  10 - 100 KW'
                     3 = ' 100+ KW'
                     . = ' Missing'
                 OTHER = ' Miscode';

 VALUE CAP_CAT_4_FMT 1 = '  0 -  10 KW'
                     2 = ' 10+ KW'
                     . = ' Missing'
                 OTHER = ' Miscode';
 RUN;


 *-----------------------------------;
 *--- IMPORT COUNTY LEVEL LPC CODE ---;
 *-----------------------------------;

 %PUT THE RATE CLASS CLASSIFICATION IS: &RC;

 DATA LPC;
  IF "&RC" = 1 THEN DO;
    LENGTH CITY_X $ 19;
    SET.LPC.'SAS$'N;
  END;

  ELSE IF "&RC" = 2 THEN DO;
    LENGTH CITY_X $ 19;
    SET LPC.'SAS2$'N;
  END;

  ELSE IF "&RC" = 3 THEN DO;
    LENGTH CITY_X $ 19;
    SET LPC.'SAS3$'N;
  END;
```

```
RUN;



*PROC CONTENTS DATA=LPC ORDER=VARNUM;
*TITLE 'COUNTY AND LPC X-WALK';
*RUN;

*PROC SORT DATA=LPC;
* BY PUC_LPC_CODE;
*RUN;

*PROC FREQ DATA=LPC;
* TABLES COUNTY;
* BY PUC_LPC_CODE;
*RUN;


*---------------------------------;

PROC SORT DATA=ETO2;
 BY CITY_X;
RUN;

PROC SORT DATA=LPC;
 BY CITY_X;
RUN;

DATA ETO3;
 MERGE ETO2(IN=INA) LPC;
 BY CITY_X;
 IF INA;
RUN;

*PROC FREQ DATA=ETO3;
* TABLES CITY*COMP_YEAR;
* WHERE PUC_LPC=.;
*RUN;

PROC FREQ DATA=ETO3;
 TABLES TECHNOLOGY STATUS PROGRAM_CODE COMP_YEAR;
 *TABLES TECHNOLOGY PV_SUB_SECTOR STATUS SIZE STATE ZIP UTILITY;
TITLE 'ETO SOLAR PV DATA 2003-2009';
RUN;

*---------------------------------;

DATA ETO4;
 SET ETO3;
 IF TECHNOLOGY = 'PV';           *--- SUBSETTING STATEMENT ---;
 IF STATUS = 'Paid';             *--- SUBSETTING STATEMENT ---;
 IF PROGRAM_CODE NE 'OPSOLAR';   *--- SUBSETTING STATEMENT ---;
 IF SYSTEM_COST GT 0;            *--- SUBSETTING STATEMENT ---;
 IF DC_CAP NE .;                 *--- SUBSETTING STATEMENT ---;
```

```
LPC_TSRF_DEG = PUC_LPC * &TSRF * &DEGRADE;
KWH_YEAR = DC_CAP * 1000 * PUC_LPC * &TSRF * &DEGRADE;
CF_YEAR = (KWH_YEAR / (DC_CAP *8760)) * 100;

LOAN_FEE = 0.70 * SYSTEM_COST * &LFR;
LOAN_AMT = 0.70 * SYSTEM_COST + LOAN_FEE;

PAYMT_600 = FINANCE('PMT',0.0600,&PERIOD,LOAN_AMT,0,0) * -1;
PAYMT_650 = FINANCE('PMT',0.0650,&PERIOD,LOAN_AMT,0,0) * -1;
PAYMT_700 = FINANCE('PMT',0.0700,&PERIOD,LOAN_AMT,0,0) * -1;
PAYMT_750 = FINANCE('PMT',0.0750,&PERIOD,LOAN_AMT,0,0) * -1;
PAYMT_800 = FINANCE('PMT',0.0800,&PERIOD,LOAN_AMT,0,0) * -1;
PAYMT_850 = FINANCE('PMT',0.0850,&PERIOD,LOAN_AMT,0,0) * -1;
PAYMT_900 = FINANCE('PMT',0.0900,&PERIOD,LOAN_AMT,0,0) * -1;
PAYMT_950 = FINANCE('PMT',0.0950,&PERIOD,LOAN_AMT,0,0) * -1;
PAYMT_1000 = FINANCE('PMT',0.1000,&PERIOD,LOAN_AMT,0,0) * -1;

INSUR = SYSTEM_COST * &INSR;
MSERV = &MS;
TCALC = &TCALC;

IF TCALC = 0 THEN DO;
  VIR_600 = (PAYMT_600 + INSUR + MSERV) / KWH_YEAR;
  VIR_650 = (PAYMT_650 + INSUR + MSERV) / KWH_YEAR;
  VIR_700 = (PAYMT_700 + INSUR + MSERV) / KWH_YEAR;
  VIR_750 = (PAYMT_750 + INSUR + MSERV) / KWH_YEAR;
  VIR_800 = (PAYMT_800 + INSUR + MSERV) / KWH_YEAR;
  VIR_850 = (PAYMT_850 + INSUR + MSERV) / KWH_YEAR;
  VIR_900 = (PAYMT_900 + INSUR + MSERV) / KWH_YEAR;
  VIR_950 = (PAYMT_950 + INSUR + MSERV) / KWH_YEAR;
  VIR_1000 = (PAYMT_1000 + INSUR + MSERV) / KWH_YEAR;
END;


IF TCALC = 1 THEN DO;
  IF DC_CAP LE 10 THEN DO;
   MSTR = 0.090;
   MFTR = 0.150;
   SSTR = 0.153;
   CMTR = MSTR + MFTR + SSTR - (MSTR * MFTR);
  END;

  IF DC_CAP GT 10 THEN DO;
   MSTR = 0.066;
   MFTR = 0.350;
   SSTR = 0.000;
   CMTR = MSTR + MFTR + SSTR - (MSTR * MFTR);
  END;

  TPREP = &TP;

  TAX_DDUCT_600 = (SYSTEM_COST * 0.067 * 0.85) + (((PAYMT_600 * &PERIOD) - LOAN_AMT) / &PERIOD)
  TAX_DDUCT_650 = (SYSTEM_COST * 0.067 * 0.85) + (((PAYMT_650 * &PERIOD) - LOAN_AMT) / &PERIOD)
  TAX_DDUCT_700 = (SYSTEM_COST * 0.067 * 0.85) + (((PAYMT_700 * &PERIOD) - LOAN_AMT) / &PERIOD)
  TAX_DDUCT_750 = (SYSTEM_COST * 0.067 * 0.85) + (((PAYMT_750 * &PERIOD) - LOAN_AMT) / &PERIOD)
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TAX_DDUCT_800 = (SYSTEM_COST * 0.067 * 0.85) + (((PAYMT_800 * &PERIOD) - LOAN_AMT) / &PERIOD)
TAX_DDUCT_850 = (SYSTEM_COST * 0.067 * 0.85) + (((PAYMT_850 * &PERIOD) - LOAN_AMT) / &PERIOD)
TAX_DDUCT_900 = (SYSTEM_COST * 0.067 * 0.85) + (((PAYMT_900 * &PERIOD) - LOAN_AMT) / &PERIOD)
TAX_DDUCT_950 = (SYSTEM_COST * 0.067 * 0.85) + (((PAYMT_950 * &PERIOD) - LOAN_AMT) / &PERIOD)
TAX_DDUCT_1000 = (SYSTEM_COST * 0.067 * 0.85) + (((PAYMT_1000 * &PERIOD) - LOAN_AMT) / &PERIOI

VIR2_600 = ((PAYMT_600 + INSUR + MSERV + TPREP) - (TAX_DDUCT_600 * CMTR)) / (KWH_YEAR * (1 - (
VIR2_650 = ((PAYMT_650 + INSUR + MSERV + TPREP) - (TAX_DDUCT_650 * CMTR)) / (KWH_YEAR * (1 - (
VIR2_700 = ((PAYMT_700 + INSUR + MSERV + TPREP) - (TAX_DDUCT_700 * CMTR)) / (KWH_YEAR * (1 - (
VIR2_750 = ((PAYMT_750 + INSUR + MSERV + TPREP) - (TAX_DDUCT_750 * CMTR)) / (KWH_YEAR * (1 - (
VIR2_800 = ((PAYMT_800 + INSUR + MSERV + TPREP) - (TAX_DDUCT_800 * CMTR)) / (KWH_YEAR * (1 - (
VIR2_850 = ((PAYMT_850 + INSUR + MSERV + TPREP) - (TAX_DDUCT_850 * CMTR)) / (KWH_YEAR * (1 - (
VIR2_900 = ((PAYMT_900 + INSUR + MSERV + TPREP) - (TAX_DDUCT_900 * CMTR)) / (KWH_YEAR * (1 - (
VIR2_950 = ((PAYMT_950 + INSUR + MSERV + TPREP) - (TAX_DDUCT_950 * CMTR)) / (KWH_YEAR * (1 - (
VIR2_1000 = ((PAYMT_1000 + INSUR + MSERV + TPREP) - (TAX_DDUCT_1000 * CMTR)) / (KWH_YEAR * (1

TAX_INCOME_600 = MAX((VIR2_600 * KWH_YEAR - TAX_DDUCT_600),0);
TAX_INCOME_650 = MAX((VIR2_650 * KWH_YEAR - TAX_DDUCT_650),0);
TAX_INCOME_700 = MAX((VIR2_700 * KWH_YEAR - TAX_DDUCT_700),0);
TAX_INCOME_750 = MAX((VIR2_750 * KWH_YEAR - TAX_DDUCT_750),0);
TAX_INCOME_800 = MAX((VIR2_800 * KWH_YEAR - TAX_DDUCT_800),0);
TAX_INCOME_850 = MAX((VIR2_850 * KWH_YEAR - TAX_DDUCT_850),0);
TAX_INCOME_900 = MAX((VIR2_900 * KWH_YEAR - TAX_DDUCT_900),0);
TAX_INCOME_950 = MAX((VIR2_950 * KWH_YEAR - TAX_DDUCT_950),0);
TAX_INCOME_1000 = MAX((VIR2_1000 * KWH_YEAR - TAX_DDUCT_1000),0);

TAX_STATE_600 = TAX_INCOME_600 * MSTR;
TAX_STATE_650 = TAX_INCOME_650 * MSTR;
TAX_STATE_700 = TAX_INCOME_700 * MSTR;
TAX_STATE_750 = TAX_INCOME_750 * MSTR;
TAX_STATE_800 = TAX_INCOME_800 * MSTR;
TAX_STATE_850 = TAX_INCOME_850 * MSTR;
TAX_STATE_900 = TAX_INCOME_900 * MSTR;
TAX_STATE_950 = TAX_INCOME_950 * MSTR;
TAX_STATE_1000 = TAX_INCOME_1000 * MSTR;

TAX_FED_600 = (TAX_INCOME_600 - TAX_STATE_600) * MFTR;
TAX_FED_650 = (TAX_INCOME_650 - TAX_STATE_650) * MFTR;
TAX_FED_700 = (TAX_INCOME_700 - TAX_STATE_700) * MFTR;
TAX_FED_750 = (TAX_INCOME_750 - TAX_STATE_750) * MFTR;
TAX_FED_800 = (TAX_INCOME_800 - TAX_STATE_800) * MFTR;
TAX_FED_850 = (TAX_INCOME_850 - TAX_STATE_850) * MFTR;
TAX_FED_900 = (TAX_INCOME_900 - TAX_STATE_900) * MFTR;
TAX_FED_950 = (TAX_INCOME_950 - TAX_STATE_950) * MFTR;
TAX_FED_1000 = (TAX_INCOME_1000 - TAX_STATE_1000) * MFTR;

TAX_SSMED_600 = TAX_INCOME_600 * SSTR;
TAX_SSMED_650 = TAX_INCOME_650 * SSTR;
TAX_SSMED_700 = TAX_INCOME_700 * SSTR;
TAX_SSMED_750 = TAX_INCOME_750 * SSTR;
TAX_SSMED_800 = TAX_INCOME_800 * SSTR;
TAX_SSMED_850 = TAX_INCOME_850 * SSTR;
TAX_SSMED_900 = TAX_INCOME_900 * SSTR;
TAX_SSMED_950 = TAX_INCOME_950 * SSTR;
TAX_SSMED_1000 = TAX_INCOME_1000 * SSTR;
```

```
TAX_TOT_600 = TAX_STATE_600 + TAX_FED_600 + TAX_SSMED_600;
TAX_TOT_650 = TAX_STATE_650 + TAX_FED_650 + TAX_SSMED_650;
TAX_TOT_700 = TAX_STATE_700 + TAX_FED_700 + TAX_SSMED_700;
TAX_TOT_750 = TAX_STATE_750 + TAX_FED_750 + TAX_SSMED_750;
TAX_TOT_800 = TAX_STATE_800 + TAX_FED_800 + TAX_SSMED_800;
TAX_TOT_850 = TAX_STATE_850 + TAX_FED_850 + TAX_SSMED_850;
TAX_TOT_900 = TAX_STATE_900 + TAX_FED_900 + TAX_SSMED_900;
TAX_TOT_950 = TAX_STATE_950 + TAX_FED_950 + TAX_SSMED_950;
TAX_TOT_1000 = TAX_STATE_1000 + TAX_FED_1000 + TAX_SSMED_1000;

VIR3_600 = (PAYMT_600 + INSUR + MSERV + TPREP + TAX_TOT_600) / KWH_YEAR;
VIR3_650 = (PAYMT_650 + INSUR + MSERV + TPREP + TAX_TOT_650) / KWH_YEAR;
VIR3_700 = (PAYMT_700 + INSUR + MSERV + TPREP + TAX_TOT_700) / KWH_YEAR;
VIR3_750 = (PAYMT_750 + INSUR + MSERV + TPREP + TAX_TOT_750) / KWH_YEAR;
VIR3_800 = (PAYMT_800 + INSUR + MSERV + TPREP + TAX_TOT_800) / KWH_YEAR;
VIR3_850 = (PAYMT_850 + INSUR + MSERV + TPREP + TAX_TOT_850) / KWH_YEAR;
VIR3_900 = (PAYMT_900 + INSUR + MSERV + TPREP + TAX_TOT_900) / KWH_YEAR;
VIR3_950 = (PAYMT_950 + INSUR + MSERV + TPREP + TAX_TOT_950) / KWH_YEAR;
VIR3_1000 = (PAYMT_1000 + INSUR + MSERV + TPREP + TAX_TOT_1000) / KWH_YEAR;

CHECK_600 = VIR2_600 - VIR3_600;
CHECK_650 = VIR2_650 - VIR3_650;
CHECK_700 = VIR2_700 - VIR3_700;
CHECK_750 = VIR2_750 - VIR3_750;
CHECK_800 = VIR2_800 - VIR3_800;
CHECK_850 = VIR2_850 - VIR3_850;
CHECK_900 = VIR2_900 - VIR3_900;
CHECK_950 = VIR2_950 - VIR3_950;
CHECK_1000 = VIR2_1000 - VIR3_1000;

IF TAX_DDUCT_600 LT (PAYMT_600 + INSUR + MSERV + TPREP) THEN VIR_600 = VIR2_600;
ELSE VIR_600 = (PAYMT_600 + INSUR + MSERV + TPREP) / KWH_YEAR;

IF TAX_DDUCT_650 LT (PAYMT_650 + INSUR + MSERV + TPREP) THEN VIR_650 = VIR2_650;
ELSE VIR_650 = (PAYMT_650 + INSUR + MSERV + TPREP) / KWH_YEAR;

IF TAX_DDUCT_700 LT (PAYMT_700 + INSUR + MSERV + TPREP) THEN VIR_700 = VIR2_700;
ELSE VIR_700 = (PAYMT_700 + INSUR + MSERV + TPREP) / KWH_YEAR;

IF TAX_DDUCT_750 LT (PAYMT_750 + INSUR + MSERV + TPREP) THEN VIR_750 = VIR2_750;
ELSE VIR_750 = (PAYMT_750 + INSUR + MSERV + TPREP) / KWH_YEAR;

IF TAX_DDUCT_800 LT (PAYMT_800 + INSUR + MSERV + TPREP) THEN VIR_800 = VIR2_800;
ELSE VIR_800 = (PAYMT_800 + INSUR + MSERV + TPREP) / KWH_YEAR;

IF TAX_DDUCT_850 LT (PAYMT_850 + INSUR + MSERV + TPREP) THEN VIR_850 = VIR2_850;
ELSE VIR_850 = (PAYMT_850 + INSUR + MSERV + TPREP) / KWH_YEAR;

IF TAX_DDUCT_900 LT (PAYMT_900 + INSUR + MSERV + TPREP) THEN VIR_900 = VIR2_900;
ELSE VIR_900 = (PAYMT_900 + INSUR + MSERV + TPREP) / KWH_YEAR;

IF TAX_DDUCT_950 LT (PAYMT_950 + INSUR + MSERV + TPREP) THEN VIR_950 = VIR2_950;
ELSE VIR_950 = (PAYMT_950 + INSUR + MSERV + TPREP) / KWH_YEAR;
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    IF TAX_DDUCT_1000 LT (PAYMT_1000 + INSUR + MSERV + TPREP) THEN VIR_1000 = VIR2_1000;
    ELSE VIR_1000 = (PAYMT_1000 + INSUR + MSERV + TPREP) / KWH_YEAR;
  END;
RUN;

PROC FREQ DATA=ETO4;
 TABLES TECHNOLOGY STATUS PROGRAM_CODE COMP_YEAR;
TITLE 'ETO SOLAR PV DATA 2003-2009';
TITLE2 'WHERE TECH=PV, STATUS=PAID, PROGRAM CODE NE OPSOLAR, SYSTEM COST GT ZERO, DC_CAP NE MISS:
RUN;

PROC SORT DATA=ETO4;
 BY COMP_YEAR;
RUN;

PROC MEANS DATA=ETO4;
 VAR COST_WATT PUC_COST_WATT DC_CAP;
 BY COMP_YEAR;
TITLE 'ETO SOLAR PV DATA 2003-2009';
TITLE2 'WHERE TECH=PV, STATUS=PAID, PROGRAM CODE NE OPSOLAR, SYSTEM COST GT ZERO, DC_CAP NE MISS:
RUN;

*----------------------------------;
*----------------------------------;

DATA ETO5;
 SET ETO4;
 IF COMP_YEAR IN (2008,2009);  *--- SUBSETTING STATEMENT ---;
RUN;


PROC FREQ DATA=ETO5;
 TABLES TECHNOLOGY STATUS PROGRAM_CODE COMP_YEAR PUC_LPC_CODE COUNTY;
 *TABLES TECHNOLOGY STATUS COMP_YEAR COST_WATT_2008_R DC_CAP_R;
TITLE 'ETO SOLAR PV DATA 2008-2009';
TITLE2 'WHERE TECHNOLOGY = PV AND STATUS = PAID AND COMP_YEAR = 2008-2009';
FORMAT COMP_YEAR 8.0 DC_CAP_R 8.2;
RUN;

PROC FREQ DATA=ETO5;
 TABLES CITY CITY_X;
 WHERE PUC_LPC_CODE=.;
TITLE 'ETO SOLAR PV DATA 2008-2009';
TITLE2 'WHERE TECHNOLOGY = PV AND STATUS = PAID AND COMP_YEAR = 2008-2009';
RUN;


ODS PDF FILE=&FILE;   *----- NAME OF OUTPUT FILE -----*;

PROC SORT DATA=ETO5;
 BY PUC_LPC_CODE CAP_CAT3;
RUN;

PROC MEANS DATA=ETO5 N P10 P25 P50 MEAN;
*PROC MEANS DATA=ETO5 N MEAN STD P50 P90;
```

```
VAR SYSTEM_COST DC_CAP PUC_COST_WATT KWH_YEAR CF_YEAR LPC_TSRF_DEG CMTR
    VIR_600 VIR_650 VIR_700 VIR_750 VIR_800 VIR_850 VIR_900 VIR_950 VIR_1000;
BY PUC_LPC_CODE CAP_CAT3;
WHERE CAP_CAT3 LE 2;
TITLE1 "STAFF VIR RATES BY RATE CLASS AND PROJECT SIZE CATEGORY -- &STEP";
TITLE2 'ETO SOLAR PV DATA 2008-2009';
TITLE3 ' ';
TITLE4 "PERIOD = &PERIOD, COUNTY CLASS = &RC, TSRF = &TSRF, DEGRADATION = &DEGRADE";
TITLE5 "LOAN FEE = &LFR, INSURANCE = &INSR, METER SERVICE = &MS, TAX CALC = &TCALC, TAX PREP = &
LABEL
    SYSTEM_COST = 'System Cost ($)'
         DC_CAP = 'Capacity - DC (kW)'
  PUC_COST_WATT = 'System Cost per Watt ($/watt)'
       KWH_YEAR = 'Expected Annual Generation (kWh)'
        CF_YEAR = 'Annual Capacity Factor (%)'
   LPC_TSRF_DEG = 'County LPC x TSRF x Degradation'
           CMTR = 'Combined Marginal Tax Rate'
        VIR_600 = 'Volumetric Incentive Rate at 6.00% ($/kWh)'
        VIR_650 = 'Volumetric Incentive Rate at 6.50% ($/kWh)'
        VIR_700 = 'Volumetric Incentive Rate at 7.00% ($/kWh)'
        VIR_750 = 'Volumetric Incentive Rate at 7.50% ($/kWh)'
        VIR_800 = 'Volumetric Incentive Rate at 8.00% ($/kWh)'
        VIR_850 = 'Volumetric Incentive Rate at 8.50% ($/kWh)'
        VIR_900 = 'Volumetric Incentive Rate at 9.00% ($/kWh)'
        VIR_950 = 'Volumetric Incentive Rate at 9.50% ($/kWh)'
        VIR_1000 = 'Volumetric Incentive Rate at 10.00% ($/kWh)'
   PUC_LPC_CODE = 'Rate Class'
       CAP_CAT3 = 'Project Size Category';
FORMAT CAP_CAT3 CAP_CAT_3_FMT.;
RUN;

PROC SORT DATA=ETO5;
BY CAP_CAT3;
RUN;

PROC MEANS DATA=ETO5 N P10 P25 P50 MEAN;
*PROC MEANS DATA=ETO5 N MEAN STD P50 P90;
VAR SYSTEM_COST DC_CAP PUC_COST_WATT KWH_YEAR CF_YEAR LPC_TSRF_DEG
    VIR_600 VIR_650 VIR_700 VIR_750 VIR_800 VIR_850 VIR_900 VIR_950 VIR_1000;
BY CAP_CAT3;
WHERE CAP_CAT3 LE 2;
TITLE1 "STAFF VIR RATES BY RATE CLASS AND PROJECT SIZE CATEGORY -- &STEP";
TITLE2 'ETO SOLAR PV DATA 2008-2009';
TITLE3 ' ';
TITLE4 "PERIOD = &PERIOD, COUNTY CLASS = &RC, TSRF = &TSRF, DEGRADATION = &DEGRADE";
TITLE5 "LOAN FEE = &LFR, INSURANCE = &INSR, METER SERVICE = &MS, TAX CALC = &TCALC, TAX PREP = &
LABEL
    SYSTEM_COST = 'System Cost ($)'
         DC_CAP = 'Capacity - DC (kW)'
  PUC_COST_WATT = 'System Cost per Watt ($/watt)'
       KWH_YEAR = 'Expected Annual Generation (kWh)'
        CF_YEAR = 'Annual Capacity Factor (%)'
   LPC_TSRF_DEG = 'County LPC x TSRF x Degradation'
           CMTR = 'Combined Marginal Tax Rate'
        VIR_600 = 'Volumetric Incentive Rate at 6.00% ($/kWh)'
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        VIR_650 = 'Volumetric Incentive Rate at 6.50% ($/kWh)'
        VIR_700 = 'Volumetric Incentive Rate at 7.00% ($/kWh)'
        VIR_750 = 'Volumetric Incentive Rate at 7.50% ($/kWh)'
        VIR_800 = 'Volumetric Incentive Rate at 8.00% ($/kWh)'
        VIR_850 = 'Volumetric Incentive Rate at 8.50% ($/kWh)'
        VIR_900 = 'Volumetric Incentive Rate at 9.00% ($/kWh)'
        VIR_950 = 'Volumetric Incentive Rate at 9.50% ($/kWh)'
        VIR_1000 = 'Volumetric Incentive Rate at 10.00% ($/kWh)'
    PUC_LPC_CODE = 'Rate Class'
        CAP_CAT3 = 'Project Size Category';
 FORMAT CAP_CAT3 CAP_CAT_3_FMT.;
RUN;


ODS PDF CLOSE;
ODS LISTING;

PROC SORT DATA=ETO5;
 BY PUC_LPC_CODE CAP_CAT3;
RUN;

PROC UNIVARIATE DATA=ETO5;
 VAR VIR_600;
 BY PUC_LPC_CODE CAP_CAT3;
 WHERE CAP_CAT3 LE 2;
TITLE1 'STAFF VIR RATES BY RATE CLASS AND PROJECT SIZE CATEGORY';
TITLE2 'ETO SOLAR PV DATA 2008-2009';
TITLE3 ' ';
TITLE4 "PERIOD = &PERIOD YEARS, TSRF = &TSRF";
TITLE5 "COUNTY CLASSIFICATION = &RC";
 *FORMAT PAYMT_KWH 9.4 CAP_CAT3 CAP_CAT_3_FMT.;
RUN;

PROC FREQ DATA=ETO5;
 TABLES COUNTY;
 BY PUC_LPC_CODE;
RUN;
```

CERTIFICATE OF SERVICE

I certify that on February 17, 2010, I served the foregoing upon AR 538 parties in this proceeding by electronic mail only.

W
ROBERT FRISBEE
rfrisbee@si-two.com

W
JOLENE GOODNIGHT
jolene.goodnight@gmail.com

W
RUSSELL HIRSCH
russell@dhgllc.com

RAINER HUMMEL
5041 SW ILLINOIS ST
PORTLAND OR 97221
rhummel@q.com

W
DAVID JOHNSON
sideoff.dave@gmail.com

W
TEDDY KEIZER
1615 SE 30TH AVE
PORTLAND OR 97214
teddy@goteddygo.com; teddy1a@aol.com

W
SEAN MICKEN
sean@resolveenergy.net

W
RAYMOND P NEFF
465-1/2 RIVER RD
EUGENE OR 97404
rpneff@efn.org

W
CLIFF TAYLOR
gentaylor@comcast.net

W
JOHN VARELDZIS
25 NW 23RD PL STE 6#397
PORTLAND OR 97210
john.vareldzis@gmail.com

W
DANIEL WELDON
19790 SOUTH FERGUSON TERRACE
OREGON CITY OR 97045
danweldon@bctonline.com

W
***OREGON DEPARTMENT OF ENERGY**
ROBERT DEL MAR
ENERGY ANALYST
625 MARION ST NE
SALEM OR 97301-3737
robert.delmar@state.or.us

KIP PHEIL
SENIOR POLICY ANALYST
625 MARION ST NE - STE 1
SALEM OR 97301-3737
kip.pheil@state.or.us

VIJAY A SATYAL
SENIOR POLICY ANALYST
625 MARION ST NE
SALEM OR 97301
vijay.a.satyal@state.or.us

W
ABUNDANT SOLAR
JAMES REISMILLER
james@abundantsolar.com

W
ADVANCED ENERGY SYSTEMS
ERIC NILL
65 CENTENNIAL LOOP
EUGENE OR 97401
eric@aesrenew.com

W
AF LEGAL & CONSULTING SERVICES
ANN L FISHER
ATTORNEY AT LAW
PO BOX 25302
PORTLAND OR 97298-0302
energlaw@aol.com

W
ALBINA COMMUNITY BANK
SCOTT BOSSOM
CREDIT ADMINISTRATOR
sbossom@albinabank.com

ATLAS MARKETS
STEVE SOULE
4203 MONTROSE BLVD STE 650
HOUSTON TX 77006
steve.soule@atlasmarkets.com

Department of Justice
1162 Court Street NE
Salem, OR 97301-4096
(503) 947-4789 Fax: (503) 378-5300

BACGEN SOLAR GROUP
MARTIN SHAIN
ONE WORLD TRADE CENTER
121 SW SALMON ST, 11TH FLR
PORTLAND OR 97204
martin@bacgensolar.com

W
BEF RENEWABLE INC
ALICE BRAY
240 SW FIRST AVE
PORTLAND OR 97204
abray@b-e-f.org

W
CITIZENS' UTILITY BOARD OF OREGON
JEFF BISSONNETTE
610 SW BROADWAY STE 308
PORTLAND OR 97205-3404
jeff@oregoncub.org

GORDON FEIGHNER
ENERGY ANALYST
610 SW BROADWAY, SUITE 308
PORTLAND OR 97205
gordon@oregoncub.org

ROBERT JENKS
610 SW BROADWAY STE 308
PORTLAND OR 97205
bob@oregoncub.org

G. CATRIONA MCCRACKEN
LEGAL COUNSEL/STAFF ATTY
610 SW BROADWAY - STE 308
PORTLAND OR 97205
catriona@oregoncub.org

CITY OF PORTLAND - PLANNING & SUSTAINABILITY
LEE RAHR
721 NW 9TH AVE STE 350
PORTLAND OR 97209
leerahr@ci.portland.or.us

CITY OF PORTLAND - PLANNING & SUSTAINABILITY
DAVID TOOZE
SENIOR ENERGY SPECIALIST
1900 SW 4TH STE 7100
PORTLAND OR 97201
dtooze@ci.portland.or.us

COLUMBIA ENERGY PARTNERS LLC
PETER P BLOOD
VP-ORIGINATION & PORTFOLIO MGMT
317 COLUMBIA ST
VANCOUVER WA 98660
pblood@columbiaenergypartners.com

W
COMMERCIAL SOLAR VENTURES
SANDRA WALDEN
REAL ENERGY SOLUCTIONS
621 SW ALDER ST #300
PORTLAND OR 97205
swalden@realcomassoc.com

DAVISON VAN CLEVE
JESSE E COWELL
333 SW TAYLOR ST., SUITE 400
PORTLAND OR 97204
jec@dvclaw.com

W
EC RENEWABLE SOLUTIONS
LAURIE HUTCHINSON
2121 NW THURMAN
PORTLAND OR 97210
laurieh@e-c-co.com

W
ECUMENICAL MINISTRIES OF OREGON
KATHLEEN NEWMAN
OREGON INTERFAITH POWER & LIGHT
1553 NE GREENSWORD DR
HILLSBORO OR 97214
knewman@emoregon.org;
k.a.newman@verizon.net

W
ENERGY TRUST OF OREGON
DOUG BOLEYN
COMMERCIAL SOLAR PROGRAM MANAGER
851 SW SIXTH AVE STE 1200
PORTLAND OR 97204
doug.boleyn@energytrust.org

KACIA BROCKMAN
851 SW SIXTH AVE - STE 1200
PORTLAND OR 97204
kacia@energytrust.org

JED JORGENSEN
RENEWABLE ENERGY PROJECT MANAGER
851 SW SIXTH AVE STE 1200
PORTLAND OR 97204
jed.jorgensen@energytrust.org

BETSY KAUFFMAN
SENIOR PROGRAM MANAGER
851 SW SIXTH AVE STE 1200
PORTLAND OR 97204
betsy.kauffman@energytrust.org

W
ENERGY TRUST OF OREGON
DAVE MCCLELLAND
SOLAR PROGRAM COORDINATOR
851 SW SIXTH AVE STE 1200
PORTLAND OR 97204
dave.mcclelland@energytrust.org

Department of Justice
1162 Court Street NE
Salem, OR 97301-4096
(503) 947-4789 Fax: (503) 378-5300

W
ENERGY TRUST OF OREGON
KEITH ROSSMAN
SOLAR PROGRAM INTERN
851 SW SIXTH AVE STE 1200
PORTLAND OR 97204
keith.rossman@energytrust.org

LIZZIE RUBADO
RESIDENTIAL SOLAR PROJECT MANAGER
851 SW SIXTH AVE STE 1200
PORTLAND OR 97204
lizzie.rubado@energytrust.org

PETER WEST
DIRECTOR OF RENEWABLE ENERGY PROGRAMS
851 SW 6TH AVE - STE 1200
PORTLAND OR 97204
peter.west@energytrust.org

ENVIRONMENT OREGON
BROCK HOWELL
ADVOCATE
1536 SE 11TH AVE STE B
PORTLAND OR 97214
brock@environmentoregon.org

W
ENVIRONMENTAL LAW ALLIANCE WORLDWIDE
JENNIFER GLEASON
1877 GARDEN AVE
EUGENE OR 97403
jen@elaw.org

ENXCO
CHRISTOPHER DYMOND
1440 NEBRASKA AVE NE
SALEM OR 97301
christopherd@enxco.com

W
ESLER STEPHENS & BUCKLEY
JOHN W STEPHENS
888 SW FIFTH AVE STE 700
PORTLAND OR 97204-2021
stephens@eslerstephens.com;
mec@eslerstephens.com

W
FIVE STARS INTERNATIONAL LTD
LYNN FRANK
2522 19TH ST SE
SALEM OR 97302
lynn.frank@fivestarsintl.com

IBEW
JOSEPH ESMONDE
15937 NE AIRPORT WAY
PORTLAND OR 97230-4958
joe@ibew48.com

IBEW LOCAL 659
RONALD W JONES
4480 ROGUE VALLEY HWY #3
CENTRAL POINT OR 97502-1695
ronjones@ibew659.org

W
IDAHO POWER COMPANY
RANDY ALLPHIN
rallphin@idahopower.com

DAVE ANGELL
PO BOX 70
BOISE ID 83707-0070
daveangell@idahopower.com

CHRISTA BEARRY
PO BOX 70
BOISE ID 83707-0070
cbearry@idahopower.com

KARL BOKENKAMP
GENERAL MANAGER-POWER SUPPLY PLANNING
PO BOX 70
BOISE ID 83707-0070
kbokenkamp@idahopower.com

JEANNETTE C BOWMAN
PO BOX 70
BOISE ID 83707
jbowman@idahopower.com

JOHN R GALE
VP - REGULATORY AFFAIRS
PO BOX 70
BOISE ID 83707
rgale@idahopower.com

BARTON L KLINE
SENIOR ATTORNEY
PO BOX 70
BOISE ID 83707-0070
bkline@idahopower.com

JEFF MALMEN
PO BOX 70
BOISE ID 83707-0070
jmalmen@idahopower.com

LISA D NORDSTROM
ATTORNEY
PO BOX 70
BOISE ID 83707-0070
lnordstrom@idahopower.com

Department of Justice
1162 Court Street NE
Salem, OR 97301-4096
(503) 947-4789 Fax: (503) 378-5300

W
IDAHO POWER COMPANY
GREGORY W SAID
DIRECTOR - REVENUE REQUIREMENT
PO BOX 70
BOISE ID 83707
gsaid@idahopower.com

MARK STOKES
MANAGER, POWER SUPPLY & PLANNING
PO BOX 70
BOISE ID 83707
mstokes@idahopower.com

W
LANE POWELL PC
CAROLYN VOGT
601 SW SECOND AVE STE 2100
PORTLAND OR 97204-3158
vogtc@lanepowell.com

W
LIUNA
BEN NELSON
LEAD ORGANIZER
nrocnelson@qwest.net

W
LIVELIGHT ENERGY
JEFF FRIEDMAN
ENERGY CONSULTANT
1750 SW 187TH AVE
BEAVERTON OR 97006
jeff@livelightenergy.com

KEITH KNOWLES
PRESIDENT
1750 SW 187TH AVE
BEAVERTON OR 97006
keith@livelightenergy.com

W
MCDOWELL RACKNER & GIBSON PC
WENDY MCINDOO
OFFICE MANAGER
520 SW 6TH AVE STE 830
PORTLAND OR 97204
wendy@mcd-law.com

LISA F RACKNER
ATTORNEY
520 SW SIXTH AVENUE STE 830
PORTLAND OR 97204
lisa@mcd-law.com

MILLER NASH ET AL
BRIAN B DOHERTY
111 SW 5TH STE 3400
PORTLAND OR 97204-3699
brian.doherty@millernash.com

W
NORTHWEST ENVIRONMENTAL BUSINESS COUNCIL
ROBERT GROTT
620 SW FIFTH AVE STE 1008
PORTLAND OR 97204
robert@nebc.org

W
NORTHWEST NATURAL
BILL EDMONDS
DIRECTOR - ENVIRONMENTAL POLICY
220 NW 2ND AVE
PORTLAND OR 97209
wre@nwnatural.com

W
NORTHWEST STRATEGIES INC
LEN BERGSTEIN
lbergstein@aol.com

ANNIE LEINEWEBER
805 SW BROADWAY STE 400
PORTLAND OR 97205
noweststra@aol.com

W
OBSIDIAN FINANCE GROUP LLC
J FRANKLIN CABLE
10260 SW GREENBURG RD STE 1150
PORTLAND OR 97223
fcable@obsidianfinance.com

JEREMY W HULL
jhull@obsidianfinance.com

W
OREGON AFL-CIO
DUKE SHEPARD
2110 STATE ST
SALEM OR 97301
duke@oraflcio.org

W
OREGON DISTRICT COUNCIL OF LABORERS'
MELODY GUY
melodyg@qwestoffice.net

OREGON MUNICIPAL ELECTRIC UTILITIES ASSOC
TOM O'CONNOR
EXECUTIVE DIRECTOR
PO BOX 928
SALEM OR 97308-0928
toconnor@teleport.com

OREGON RURAL ELECTRIC COOPERATIVE ASSN
SANDRA FLICKER
1750 LIBERTY ST SE
SALEM OR 97302-5159
sflicker@oreca.org

OREGON SOLAR ENERGY INDUSTRIES ASSOCIATION
DESARI STRADER
EXECUTIVE DIRECTOR
3855 SW 153RD DR
BEAVERTON OR 97006
desari@oseia.org

W
OREGONIANS FOR RENEWABLE ENERGY PAYMENTS
JUDY BARNES
1425 SE 37TH
PORTLAND OR 97214
jbarnes@hevanet.com

MARK PETE PENGILLY
PO BOX 10221
PORTLAND OR 97296
mpengilly@gmail.com

OSEIA
SETH PRICKETT
DIRECTOR, PUBLIC POLICY GOVT AFFAIRS
3548 NE SIXTH AVE
PORTLAND OR 97212
sethprickett@gmail.com

W
PACIFIC ENERGY VENTURES LLC
JUSTIN KLURE
jklure@peventuresllc.com

W
PACIFIC POWER & LIGHT
ERIK ANDERSON
825 NE MULTNOMAH ST STE 1800
PORTLAND OR 97232
erik.anderson@pacificorp.com

JOELLE STEWARD
REGULATORY MANAGER
825 NE MULTNOMAH STE 2000
PORTLAND OR 97232
joelle.steward@pacificorp.com

W
PACIFICORP
KYLE L DAVIS
MGR ENV POLICY & STRATEGY
825 NE MULTNOMAH STE 2000
PORTLAND OR 97232
kyle.l.davis@pacificorp.com

W
PACIFICORP
RYAN FLYNN
LEGAL COUNSEL
825 NE MULTNOMAH, SUITE 1800
PORTLAND OR 97232
ryan.flynn@pacificorp.com

PETER ROBERTS LLC
PETER ROBERTS
3731 PINE CANYON DR
EUGENE OR 97405
peterbroberts@comcast.net

W
PORTLAND GENERAL ELECTRIC
DOUG KUNS
121 SW SALMON ST
1WTCO702
PORTLAND OR 97204
doug.kuns@pgn.com

BRENDAN MCCARTHY
STATE AFFAIRS SPECIALIST
121 SW SALMON ST 1WTC0301
PORTLAND OR 97204
brendan.mccarthy@pgn.com

PORTLAND GENERAL ELECTRIC COMPANY
J RICHARD GEORGE
ASST GENERAL COUNSEL
121 SW SALMON ST 1WTC1301
PORTLAND OR 97204
richard.george@pgn.com

PUBLIC UTILITY COMMISSION OF OREGON
THERESA GIBNEY
PO BOX 2148
SALEM OR 97308
theresa.gibney@state.or.us

W
RATES & REGULATORY AFFAIRS - NW NATURAL
JENNIFER GROSS
220 NW 2ND AVENUE
PORTLAND OR 97209
jennifer.gross@nwnatural.com]

W
REC SOLAR
ANDREW NOEL
833 SE MAIN ST
PMB 134
PORTLAND OR 97214
anoel@recsolar.com

Department of Justice
1162 Court Street NE
Salem, OR 97301-4096
(503) 947-4789 Fax: (503) 378-5300

W
RENEWABLE ENERGY SYSTEMS
KIRPAL KHALSA
PO BOX 2192
CAVE JUNCTION OR 97523
solarworks@gmail.com

W
RENEWABLE NORTHWEST PROJECT
ANN ENGLISH GRAVATT
POLICY DIRECTOR
917 SW OAK - STE 303
PORTLAND OR 97205
ann@rnp.org

SUZANNE LETA LIOU
SENIOR POLICY ADVOCATE
917 SW OAK STE 303
PORTLAND OR 97205
suzanne@rnp.org

RESEARCH 13
BOB BEAULAURIER
2597 KILHENNY CT
WEST LINN OR 97068
bob@research13.com

W
RS ENERGY LLC
DAVID RICHARDS
20915 SW 105TH AVE
TUALATIN OR 97062-9511
david@rs-s2s.com

W
SOLAR CITY
COLIN MURCHIE
4007 29TH ST
MT. RAINIER MD 20712
cmurchie@solarcity.com

W
SOLAR ENERGY SOLUTIONS, INC.
ANDREW KOYAANISQATSI
PRESIDENT
3730 SE LAFAYETTE CT
PORTLAND OR 97202
andrew@solarenergyoregon.com

SOLARCITY
ROB LAVIGNE
6312 SW CAPTIOL HWY., NO. 180
PORTLAND OR 97239
rlavigne@solarcity.com

W
SOLARWORLD CALIFORNIA
JANET M GAGNON
GOVERNMENT RELATIONS MANAGER
4650 ADOHR LN
CAMARILLO CA 93012
janet.gagnon@solarworldusa.com

W
STATE CAPITOL
REPRESENTATIVE TOBIAS READ
PO BOX 2101
BEAVERTON OR 97075
rep.tobiasread@state.or.us

W
STOEL RIVES LLP
DINA M DUBSON
900 SW FIFTH AVE STE 2600
PORTLAND OR 97204-1268
dmdubson@stoel.com

STEPHEN C HALL
900 SW FIFTH AVE - STE 2600
PORTLAND OR 97204-1268
schall@stoel.com

W
SUNEDISON
JOE HENRI
12500 BALTIMORE AVE
BELTSVILLE MD 20705
jhenri@sunedison.com

RUSS WRIGHT
rwright@sunedison.com

W
SUNLIGHT SOLAR ENERGY INC
CHANCE CURRINGTON
PROJECT MANAGER
chance.currington@sunlightsolar.com

W
SUSTAINABLE SOLUTIONS UNLIMITED LLC
STEVEN MCGRATH
1339 SE 8TH AVE # B
PORTLAND OR 97214
steve@solutions21st.com

W
TANGERINE SOLAR
STANLEY FLOREK
3518 FREMONT AVE N STE 267
SEATTLE WA 98103
stanley.florek@tangerinesolar.com

W
TANNER CREEK ENERGY
ALAN HICKENBOTTOM
PRESIDENT
4210 SW ALTADENA AVE
PORTLAND OR 97239
alan@tannercreekenergy.com

CRAIG STEWART
4210 SW ALTADENA AVE
PORTLAND OR 97239
craig@tannercreekenergy.com

W
THREE PHASE ELECTRIC
ROBERT LANE
rlane@threephaseelectric.com

TONKON TORP LLP
JACK ISSELMANN
888 SW FIFTH AVE STE 1600
PORTLAND OR 97204
jack.isselmann@tonkon.com

UNIVERSITY OF OREGON
FRANK E VIGNOLA
DEPARTMENT OF PHYSICS
1274 UNIVERSITY OF OREGON
EUGENE OR 97403-1274
fev@uoregon.edu

VOLTAIR WIND POWER INC
ROBERT MIGLIORI
24745 NE MOUNTAIN TOP RD
NEWBERG OR 97132
robert.migliori@gmail.com

W
VOTE SOLAR
CLAUDIA EYZAGUIRRE
400 BRANNAN ST STE 609
SAN FRANCISCO CA 94107
claudia@votesolar.org

WALMART
STEVE W CHRISS
2001 SE 10TH ST
BENTONVILLE AR 72716-0550
stephen.chriss@wal-mart.com

Neoma Lane

Neoma Lane
Legal Secretary
Department of Justice
Regulated Utility & Business Section

Department of Justice
1162 Court Street NE
Salem, OR 97301-4096
(503) 947-4789 Fax: (503) 378-5300