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HAND DELIVERED
November 19, 2007

Commonwealth of Pennsylvania
Secretary's Bureau
Pennsylvania Public Utility Commission
400 North Street
Keystone Building
2nd Floor, Room-N201
Harrisburg, PA 17120

Re: Docket Nos. M-00051865, L-00050174 and L-00050175	Net Metering and Interconnection Regulations at 52 Pa. Code §§ 75.1 et seq. to Conform with the Language of Act 35 of 2007

Dear Secretary McNulty:

Please find the enclosed fifteen (15) copies of the Mid-Atlantic Solar Energy Association (MSEIA) and Solar Alliance's comments on the revisions to the Net Metering and Interconnection Regulations at 52 Pa. Code §§ 75.1 et seq. to conform with the language of Act 35 of 2007.

Respectfully Submitted,

Ron Celentano
V.P. for Pennsylvania
Mid-Atlantic Solar Energy Industries Association

Enclosures

Before the Pennsylvania Public Utility Commission
Net Metering and Interconnection Regulations at 52 Pa. Code §§ 75.1 et seq. to Conform with the Language of Act 35 of 2007

Docket Nos. M-00051865, L-00050174 and L-00050175

Comments on the Revisions to Net Metering and Interconnection Regulations Conform with the Language of Act 35 of 2007
by
Mid-Atlantic Solar Energy Industries Association (MSEIA)
and
The Solar Alliance

Hand Delivered
November 19, 2007

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Introduction

Mid-Atlantic Solar Energy Association (MSEIA) and the Solar Alliance appreciate the opportunity to submit comments on the revisions to the Net Metering and Interconnection Regulations at 52 Pa. Code §§ 75.1 et seq., to conform with the language of Act 35 of 2007.

MSEIA is a not-for-profit trade association of companies and businesses working in New Jersey, Pennsylvania and Delaware who are involved in the development, manufacturing, design, construction and installation of solar photovoltaic (PV) and solar thermal systems. MSEIA is the local chapter of the national Solar Energy Industries Association (SEIA), which has nearly 500 members, including solar equipment manufacturers, installation companies, financing companies, and electric utilities.

The Solar Alliance is a state-focused alliance of manufacturers, integrators and financiers that are dedicated to accelerating the promise of solar energy in the United States. The Solar Alliance specifically targets our efforts to help legislators, regulators and utilities make the transition to solar power by providing the technical and policy expertise that is in the best interest of residential, commercial and government customers and Americans as a whole.

Current Solar Alliance Board Members include BP Solar, Conergy, Energy Innovations, Evergreen Solar, First Solar, Kyocera Solar, MMA Renewable Ventures, PPM Solar, Sanyo Energy, Schott Solar, Sharp Electronics Corp.-Solar Energy Solutions Group, SolarWorld, SunEdison, SunPower, Suntech and Uni-Solar. Current Solar Alliance

Associate Members are American Solar Electric, DT Solar-Turner Renewable Energy, REC Solar, SPG Solar, Mitsubishi Electric and Xantrex.

Overall Comment Regarding Net Metering

Annualized net metering should be a very straightforward process. It is simply based on two utility meter readings – one taken at the beginning, and one taken at the end of an annual period; thus, the amount of annual electricity supplied by the utility to a Customer-Generator's site can be determined, and the amount of the overall electric bill can be reconciled. In most cases, the difference of the annual meter readings will be positive, which means more power was delivered to the Customer-Generator than was exported to the grid over the annual period. No reconciliation may be necessary in this case because the Customer-Generator automatically received full retail value for the on-site generation they produced throughout the year – though, there may be some accounts that need to be settled. If the difference of the meter readings is negative, which is less likely, then the utility compensates the Customer-Generator equal to the excess generation at the avoided cost of energy. We are not suggesting that the utility change it's billing frequency or process in any way, just that the annualized net metering electricity should be based on utility meter readings taken at the beginning and end of the annual period. Examples are shown below, illustrating these scenarios.

With regard to annual excess generation, the general definition of net metering has always been intended to be limited by the annual electric usage at the interconnected facility. Ideally, an on-site generator would be sized to produce the exact amount of electricity that is consumed annually at the site. If the on-site generator production exceeded the annual consumption, then the Customer-Generator would either be compensated for the annual excess electricity valued at avoided cost, or the annual excess electricity could be forfeit entirely to the EDC. The net metering concept was never intended to exploit the electric utility billing system by essentially becoming an independent power producer (IPP) and generate a windfall from excess generation.

Responses to the Questions

1. *What is the meaning of "full retail value for all energy produced"? Act 35 does not specifically define this term. The term could be interpreted as meaning the fully bundled retail rate for generation, transmission, distribution, and any applicable transition charges. Alternatively, given the Legislature's use of the terms "excess generation" and "energy" it also could be interpreted as being limited to the generation component of the retail rate.*

   We have always understood the term, "full retail value" to mean the fully bundled retail rate, including generation, transmission, distribution and any applicable transition charges. The word "full" in the term is intended to include all the parts; otherwise, what would the word "full" imply? In contrast, for illustration, the term "partial retail value" – which is not used anywhere - would imply anything less than all four of these components, such as generation, only.

It seems that when the basic words "generation" and "energy" are used in the context of particular sentences, they can take on different meanings. There are two perspectives: 1). the utility side, consisting of conventional electricity broken up into generation, transmission, distribution, and transition components, and 2) the on-site generator side, consisting simply of energy or generation. The latter does not have a transmission part, or a distribution part, etc. It is simply energy, generation, electricity, etc. This is no other way to describe the power output of the on-site generator other than a complete product. When the term "excess generation" or "excess energy" is used, it is related to the output of the on-site generator, which is a whole bundled unit of power, regardless of whether it is larger than the electrical consumption at the facility. "Excess generation" or "excess energy" simply refers to the surplus power that is generated on-site beyond the on-site usage from grid power.

Act 35 states the following:

THE COMMISSION SHALL DEVELOP TECHNICAL AND NET METERING INTERCONNECTION RULES FOR CUSTOMER-GENERATORS INTENDING TO OPERATE RENEWABLE ONSITE GENERATORS IN PARALLEL WITH THE ELECTRIC UTILITY GRID, CONSISTENT WITH RULES DEFINED IN OTHER STATES WITHIN THE SERVICE REGION OF THE REGIONAL TRANSMISSION ORGANIZATION THAT MANAGES THE TRANSMISSION SYSTEM IN ANY PART OF THIS COMMONWEALTH.

None of the other states within the service area of the RTO define the excess generation from an on-site generator to be valued at only the debundled "energy" rate - therefore, this would be *inconsistent* with the neighboring state regulations. Net metering now exists in 42 states in the U.S. – none of which define excess generation from an on-site generator as only the decoupled generation component.

Finally, in the **Final Rulemaking Re Net Metering for Customer-generators (L-00050174)**, under "EGS Net Metering - §§ 75.13(a) and (b)" it states the following,

> *The proposed regulations expressly permit, but do not require, EGS's to offer net metering programs to their customers.*

If "excess generation" were defined as just the generation portion of electricity, then the above clearly implies that the Customer-Generator will most likely receive nothing for their excess, since the EGS is not obligated by the Commission to pay anything - this is even more inconsistent with other state regulations.

2. *What are the projected costs associated with these competing interpretations, that is, given a projected level of net metered generation (kwh), what are the projected costs to the remaining customers of an EDC if net-metered customer-generators receive* × *cents per kwh versus y cents per kwh?*

The range of assumptions needed to calculate this cost difference are much too broad to justify any reasonable results. If we postulate that "X" represents the scenario where Customer-Generators receive full retail value – including the value of all the components, generation, transmission, distribution, and transition charges, and "Y" represents only the generation charge, then the "X" scenario needs to be broken down into two sub-scenarios. Both of these "X" sub-scenarios can be differentiated by how of the annual excess generation or power output from the on-site generator is valued. One of these sub-scenarios could define this value at "full retail value" for the annual excess generation, while the other could define the value at "avoided cost". These two "X" sub-scenarios, along with the "Y" scenario would all yield different results. However, we believe the net metering definition was intended to represent the former sub-scenario – that is, annual excess generation is valued at the avoided cost.

3. *How should any residual stranded cost charges be treated in the annual reconciliation?*

Any issues regarding stranded costs or reconciliation of stranded costs are not evident in Act 35, whatsoever. However, in **Final Rulemaking Re Net Metering for Customer-generators (L-00050174)**, under "§ 75.15. Treatment of Stranded Costs", there is much discussion on the insignificance of the accumulated stranded costs from Customer-Generators..

One way of reviewing this is to assume that most all the net metering Customer-Generators would be those defined under the Solar Share requirement. Of course, there would be non-solar net metering Customer-Generators as well, such as anaerobic digesters in the agricultural sector in Tier 1. Considering that all rate caps come off by January 1, 2011, we can assume for illustration, that all the MWh required under the Solar Share by end of 2010 plus a very small percentage of Tier 1, maybe 5%, could represent an overestimated amount of energy generated by net metered Customer-Generators (e.g., anaerobic digesters). The solar Customer-Generators would have offset about 4,600 MWh, along with the assumed 5% of the Tier 1, or about 50,000 MWh by the time rate caps all come off, totaling about 55,000 MWh. Assuming the transition charge, on average across the state is $0.01/kWh, the estimated stranded costs offset by net metering would only total to about $550,000. This is a relatively small cost to the ratepayers for lost CTC revenue. Therefore, we recommend that tracking the lost stranded costs from net metering customers is hardly worth the EDC's or the PUC's administrative efforts.

4. *Are there any additional issues to be addressed by moving the reconciliation of excess energy from a monthly to an annual basis?*

It is extremely important that net metering is defined as intended by the legislature. The Proposed Rulemaking Re Net Metering for Customer- generators (L-00050174), dated November 10, 2005, had all the elements in place and properly interpreted net metering as it was intended. But, unfortunately, and unintentionally, the definition of net metering had changed for the worse in the Final Rulemaking .

Several months ago, PPL circulated an example of a net metering scenario, which implied that the Customer-Generator would make a windfall based on the recently revised net metering language in Act 35. However, the results in this example are deceiving because it only covers 6 months rather than a full year or annual period.

For illustration, the following shows three net metering billing examples for a solar PV application at a residence – Examples 1 & 3 assume the intended interpretation of net metering, whereas, Example 2 shows the results of a *misinterpreted Final Rulemaking* version is allowed to stand.

For simplicity, it is assumed that the annual period is made up of only four billing cycles, and that the following unbundled billing charges are used in these examples:

Generation charge	6.49 ¢/kWh
Transmission charge	1.29 ¢/kWh
Var. Distribution charge	4.76 ¢/kWh
Transition charge (CTC)	3.03 ¢/kWh
Total	15.57 ¢/kWh

Example 1. Intended Net Metering Scenario - w/Excess Billing Period Generation

Billing Period	Total Usage (kWh)	Total Solar Production (kWh)	Net Usage by Billing Cycle (kWh)	Carry Over as Credit		Billing Status	Adjusted Bill to Customer
1	2,000	1,000	1,000	0 kWh	$ 0.00	$ 155.70	$ 155.70
2	2,000	2,500	-500	500 kWh	$ 77.85	$ (77.85)	$ 0.00
3	2,000	2,500	-500	500 kWh	$ 77.85	$ (77.85)	$ 0.00
4	2,000	1,000	1,000	0 kWh	$ 0.00	$ 155.70	$ 0.00
Annual	8,000	7,000	1,000	0 kWh	$ 0.00	$ 155.70	$ 155.70

<u>Example 1</u> : Assumes an annual consumption of 8,000 kWh and an annual solar production of 7,000 kWh, whereby any surplus at the end of any billing period is carried over as full retail credit (@ 15.57 ¢/kWh) to the next billing period, thus yielding an overall electric bill payment of $155.70 by the end of the year.

Example 2. *Unintended* Net Metering Scenario w/Excess Billing Period Generation

Billing Period	Total Usage (kWh)	Total Solar Production (kWh)	Net Usage by Billing Cycle (kWh)	Carry Over as Credit		Billing Status	Adjusted Bill to Customer
1	2,000	1,000	1,000	0 kWh	$ 0.00	$ 155.70	$ 155.70
2	2,000	2,500	-500	500 kWh	$ 32.45	$ (32.45)	$ 0.00
3	2,000	2,500	-500	500 kWh	$ 32.45	$ (32.45)	$ 0.00
4	2,000	1,000	1,000	0 kWh	$ 0.00	$ 155.70	$ 90.80
Annual	8,000	7,000	1,000	0 kWh	$ 0.00	$ 246.50	$ 246.50

Example 2 : Assumes the same consumption and solar production as in Example 1, but any excess generation is valued at the utility's generation rate and credited to the next billing period, thus yielding an overall electric bill payment of $246.50 by the end of the year, or $90.80 more than intended (compared to Example 1). *This is essentially what already exists under the Final Rulemaking Re Net Metering for Customer-generators (L-00050174). If the Commission orders that the monthly excess generation is valued at only the generation rate, then the net metering definition will not have changed at all since the previous Final Ruling.*

Example 3. Intended Net Metering Scenario w/Excess Annual Generation

Billing Period	Total Usage (kWh)	Total Solar Production (kWh)	Net Usage by Billing Cycle (kWh)	Carry Over as Credit		Billing Status	Adjusted Bill to Customer
1	2,000	1,500	500	0 kWh	$ 0.00	$ 77.85	$ 77.85
2	2,000	3,000	-1,000	1,000 kWh	$ 155.70	$ (155.70)	$ 0.00
3	2,000	3,000	-1,000	1,000 kWh	$ 155.70	$ (155.70)	$ 0.00
4	2,000	1,500	500	0 kWh	$ 0.00	$ 77.85	$ 0.00
Annual	8,000	9,000	-1,000	1,000 kWh	$ 64.90*	$ (64.90)*	$ (142.75)*

Example 3 : This example assumes the solar PV system generates more than the usage over the annual period, with the annual consumption of 8,000 kWh and an annual solar production of 9,000 kWh. Same as in Example 1, any surplus at the end of any billing period is carried over as full retail credit to the next billing period. However, at the end of the year, the consumption/generation is reconciled or "trueed up", such that the annual excess generation is not valued at the full retail rate, rather it is valued at the avoided cost, or for this example, the generation rate. Since the on-site solar PV system generated more than the annual consumption, the overall annual bill would be $0.00. Therefore the EDC would need to reimburse the Customer-Generator for $77.85, which was previously paid at the end of billing period 1, in addition to the payment of $64.90 (1,000 kWh x 6.49 ¢/kWh) for the annual excess generation valued at avoided cost, totaling an overall payment to the Customer-Generator for $142.75.

As mentioned at the beginning of these comments under, *Overall Comment Regarding Net Metering*, only two meter readings are necessary to simply account for the annualized net metering process – taken one year apart from each other. Looking at Example 1, the customer would be billed as usual for any electricity consumed during a billing period. But, at the end of the year, the difference between the meter readings taken at the beginning of the billing period 1 and the end of billing period 4 reveals that 1,000 kWh was consumed by the Customer-Generator from the utility – but, this was already paid for within that annual period, so, this bill has already been settled. Whereas, in Example 3, the two meter readings of the annual period reveals –1,000 kWh, or that this amount was exported in excess to the utility – billing reconciliation is needed.

5. *Act 35 does not define the phrase "annual basis." Does this phrase mean a calendar year, fiscal year or does it correspond with the AEPS compliance period of June 1 through May 31?*

We prefer that "annual basis" or the annual period be based on the calendar year; however, it should be defined so that it is convenient for record keeping – having too many different definitions of annual periods may be problematic in the future.

It is important, however, that the meter readings used for annual net metering and the monthly billing are taken at the same time, from the same meter reading value. For the calendar year, for example, this may not be exactly on January 1 – it may depend on the customer's actual meter reading date closest to the beginning of the year (e.g., January 18).

6. *Should demand charges for distribution, transmission and generation services paid by net metered customers be adjusted? If so, should each component of the demand charge be adjusted to reflect the net flow of energy through a net meter? How should the adjustments be calculated?*

We feel that the "full retail value" definition should also apply to bundled billed demand charges, just like it should for electric energy charges. However, as can be seen in the the case-study illustrated below, the actual peak power generated is not exactly coincident with the peak demand at a facility; therefore, the Customer-Generator may loose out on some of the overall bill savings.

Perhaps customers with solar PV could have a special type of time-of-use rate structure that is specifically designed around the peak period, such as 10 am to 2 pm. But, it is likely that demand charges may disappear altogether in the near future, since advanced metering technology along with sophisticated billing systems will probably be utilized to bill based on some form of real-time pricing of electricity.

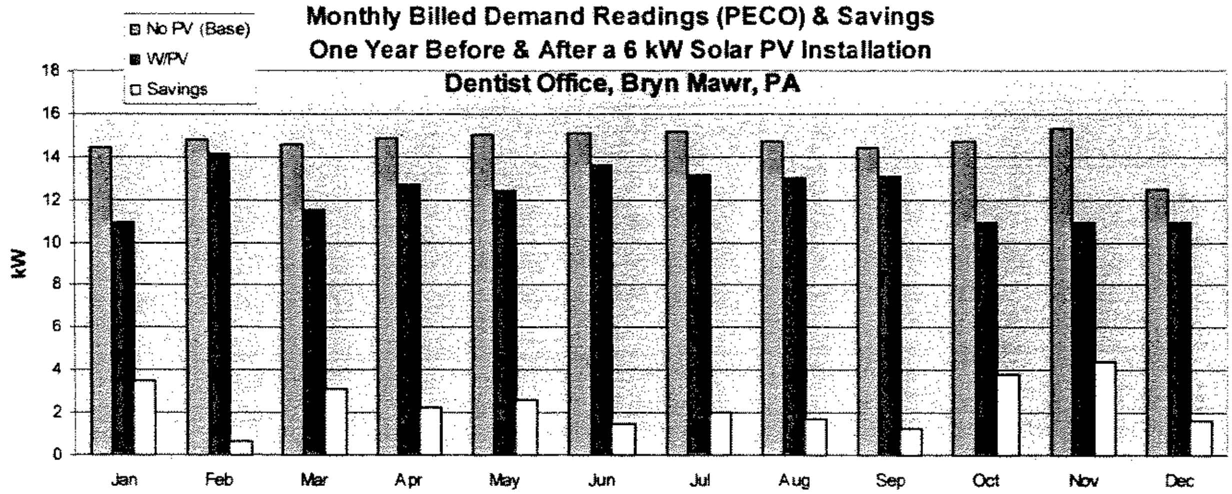
Net metering is now available in 42 states in the U.S. To the best of our knowledge, none of them directly addresses demand charges as we wish they could. For commercial (non-residential) customer accounts, monthly peak demand is indirectly measured along with monthly energy consumption for calculating the electric bill. Depending on the tariff structure, there may be a demand charge applied to the peak demand, or the peak demand is used to allocate the monthly electricity into the tiered energy blocks associated with different energy rates.

Unless it is a time-of-use tariff, the monthly peak demand is indirectly measured (typically, measured energy consumption integrated of 15 minute intervals) on a continuous basis (over 24 hours). Furthermore, the peak demand reading continues to ratchet up each time the facility electric demand increases until the end of the billing period. Also, depending on the tariff, the monthly peak demands may be ratcheted to determine an annual peak demand which is used for billing the customer throughout the year.

Typically for most commercial facilities, the summer peak demand will occur in the afternoon on a hot sunny day, when the air conditioning units are running. Peak solar power is usually generated between around 11:30 am and 12:30 pm Eastern Standard Time, depending on orientation of the solar PV array and other factors. However, the facility's peak demand may occur around 2 pm or 3 pm, or that the demand is relatively constant much of the afternoon. In this case, the solar PV system does not provide all of its peak power production at the same time when the facility's peak demand occurs. This becomes particularly problematic for a small group of market segments, such as restaurants, which may typically have their peak demands in the evening, due to later operating schedules.

In these cases, or when the solar PV system capacity is very small compared to the facility's peak demand, the solar PV system may hardly reduce the billed demand, if at all, but it will still reduce the billed energy usage – though it will be based on the tail energy block with the lowest electric rate. This is not to say that solar PV doesn't contribute to reducing the *actual* demand at the facility or reducing the utility's system peak demand as a whole, it is that for some facilities, their billed demands may be significantly out of synch compared to when maximum solar power is being generated in the daytime.

However, many of the commercial customers can see both their billed demand and billed energy use reduced from having a solar PV system. Below is a recent case study of a dentist office in Bryn Mawr, PA that has a 6 kW solar PV system, installed over one year ago. As can be seen from the graph below, the peak demand was reduced every month, ranging from 0.7 kW to 4.4 kW, or averaging about 2.4 kW per month.



This customer is on PECO's General Service tariff with block rates. Upon review of the PECO bills, the solar PV system reduced the billed demands, which in turned reduced the energy in all of the energy blocks.

7. *Should the Commission provide monthly credits for net metered accounts, and carry over monthly excess generation to the next billing month, with any remaining excess energy (where total annual generation of energy exceeds total annual usage) cashed out at the end of the year? Alternatively, do the metering regulations only provide for annual compensation for excess generation in any month?*

As expressed throughout these comments, simply letting any monthly excess generation automatically carry over as full retail value credit into the next billing period is clearly the preferred approach . This simple and automated process will save ratepayers the unnecessary cost to administer monthly bill reconciliation and cutting small checks to Customer-Generators. Far less checks will need to be cut by waiting to the end of an annual period after settling net metering billing accounts.

As administrator of the Sustainable Development Solar Grant Program, I must have received phone calls or emails from over 30 solar PV Customer-Generators that have had PECO billing problems - they are not getting correct bill reduction based on PECO's two meter system. Every one of these customers simply wants their solar PV system to reduce their electric bills and have any monthly excess generation rolled over into the next billing period based on the full retail value of all the bundled components of the electric bill.

ADDITIONAL COMMENTS

Assigned Contacts at the EDCs (Net Metering)

We have expressed this comment many times in the past, but have yet to see any language in recent regulations. We strongly urge the Commission to require each EDC to designate a contact person from whom information on net metering and the EDC's billing system can be obtained through informal requests regarding a proposed project. But, more importantly, this contact person is the one to address any net metering billing issues which may arise after the project is in operation.

The experience in Pennsylvania, PECO Energy's service territory in particular, as well as in other states has shown that often meter and billing issues arise in the application of net-metering. When these issues are not resolved, the customer generators are not receiving the value of the net-metering; they are being overcharged for electricity. The EDC's need to be responsive in resolving these issues and compensating the customer generators for the overpayment. Language should be included in the net metering rule that defines what will happen in the event of the metering/billing issue, how it will be resolved, who is responsible for resolving the issue, how the customer generator receives repayment, and in the event that the EDC is non-responsive, that certain penalties should be assessed that would incentivize resolution of these issues. A method for seeking PUC penalties should be included in this language.

Virtual Net Metering

We applaud the Commission for defining Virtual Net Metering in the **Final Rulemaking Re Net Metering for Customer-generators (L-00050174)**. Of the 42 other states in the U.S. that permit some form of net metering, none of them has this very innovative option that can allow communities to further benefit from solar PV and other on-site generation technologies. However, there are two issues that would enhance this option:

1) Billing Allocation to Other Accounts – In the **Final Rulemaking Re Net Metering for Customer-generators (L-00050174)**, under § 75.13. General provisions (C), it states the following at the end of the section:

.... FOR CUSTOMER-GENERATORS INVOLVED IN VIRTUAL METER AGGREGATION PROGRAMS, A CREDIT SHALL BE APPLIED FIRST TO THE METER THROUGH WHICH THE GENERATING FACILITY SUPPLIES ELECTRICITY TO THE DISTRIBUTION SYSTEM, THEN THROUGH THE REMAINING METERS FOR THE CUSTOMER-GENERATOR'S ACCOUNT *EQUALLY* AT EACH METER'S DESIGNATED RATE.

We feel both the Customer-Generators and the EDCs would prefer that excess electricity be credited to a prioritized list of assigned meter accounts in a cascading fashion, rather than be allocated equally across assigned meter accounts. For example, if five secondary accounts under the same account holder were assigned to a priority account with an interconnected solar PV system, then any monthly excess generated electricity would first be credited to one of the selected secondary accounts, with any remaining surplus credited to the remaining accounts based on their assigned queue position. This would offer the most billing credit to all the accounts as a whole. Furthermore, it would significantly reduce the EDC's efforts with regard to calculating the bills for each of the accounts; otherwise, the EDC has to adjust all the accounts even though there may be very little monthly surplus. At the end of the annual period, all the accounts can be reconciled in a collective manner, as if it were a single account.

2) Physical Boundary Definition – Both the **Final Rulemaking Re Net Metering for Customer-generators (L-00050174)** and **Act 35** define and clarify that the physical boundary for a virtual net metering application is within a two mile radius within a single EDC's service territory. We agree that the virtual net metering application should stay within the bounds of the given EDC, but we are puzzled why there is a much tighter limitation of a two mile radius. A university can easily span well beyond a two mile radius. The two mile restriction limits the ability of customer/generators in less developed areas to take advantage of virtual net metering. In the absence of any compelling technical or administrative reason to limit of virtual net metering, we ask r the Commission to consider extending the virtual net metering boundary to the full extent of the EDC's regional boundary.

Outstanding Interconnection Issues

We have several comments regarding outstanding interconnection issues. They are as follows:

1) Assigned Contacts at the EDCs - Although in the **Final Rulemaking Re Interconnection Standards for Customer-generators (L-00050175)** there is language requiring the EDCs to assign a contact person for interfacing with the Customer-Generator at the beginning phase of projects with regard to interconnection - it seems that not much has changed since this ruling has taken effect. Finding a contact within an EDC has not been easy, let alone communicating with them. It would be helpful for the EDC to post a contact phone number on their websites along with general information about the interconnection requirements, the application process, and any other pertinent information related to interconnection issues.
It is worth mentioning that PPL has had a contact for interconnection issues for the past several years and it has been very effective for swiftly moving projects along. This is also true with First Energy (MetEd).

2) Interconnection Application Forms - Although a working group was created to address statewide interconnection application forms, and some of these forms have already been completed, it is unclear how the final forms become adopted by all the EDCs – what is the procedure for this to happen? For example, the Level 1 interconnection application form has been completed and signed off by the working group since March of 2007, but it is not being used by any of the EDCs except perhaps First Energy. We are not sure if some of the other EDCs are up to speed with even knowing that standardized interconnection forms are required.

3) Fees for Level 1 Applications – This is still an outstanding issue. We strongly feel there should be no fee for Level 1 (up to 10 kW) interconnection applications, such as in several other states. However, this issue has not been resolved. PPL does not charge anything for Level 1 applications, while First Energy feels a fee is justified to cover the additional time dealing with incomplete applications.

However, this is a very simple two page application form, mostly consisting of contact information fields. A simple one-line electrical diagram and a simple site plan is required to accompany the application. Normally this should take well under an hour to process. We feel this is an insignificant administrative cost for the EDC to process, or that the application fees from the Levels 2 through 4 could subsidize this small cost. We can appreciate that several rounds of dealing with incomplete applications can start to become burdensome for the EDCs. We feel that if an application fee is to be considered, it should only be in the form of a penalty fee for incomplete applications – this will speed up the learning curve for applicants to submit complete applications.

4) Utility Isolation Switch – Lockbox Option – As stated in the **Final Rulemaking Re Interconnection Standards for Customer-generators (L-00050175),** the Customer-Generator is required to install a utility isolation switch or disconnect switch that is accessible from the outside. Although we strongly argued that this is an unnecessary and costly measure, we appreciate that the Commission offered an alternative option for the Customer-Generator to install a lockbox to contain a key for the utility to have access to a disconnect switch. This lockbox is to be supplied by the EDC' however, it has not been established who pays for this item.

We strongly feel it is unfair for the Customer-Generator to bear this cost and that the EDC should provide it free of charge.

We appreciate the opportunity to participate in this special request for comments on the revisions to the net metering and interconnection regulations. As this very long and ongoing process comes to a close through a final rulemaking, we hope that the Commission will make the very important decisions to help minimize the barriers for the solar energy industry to successful grow in Pennsylvania.