BEFORE THE PENNSYLVANIA
PUBLIC UTILITY COMMISSION

Implementation of the Alternative Energy Docket No. M-00051865 Portfolio Standards Act of 2004 Rulemaking Re Electric Distribution Docket No. L-00040169 Companies' Obligation to Serve Retail Customers at the Conclusion of the Transition Period Pursuant to 66 Pa. C.S. § 2807(e)(2)	Comments of PV Now in cooperation with the Mid-Atlantic Solar Energy Industries Association (MSEIA) and the national Solar Energy Industries Association (SEIA). PV Now c/o 33 Greening Life Lane Shermans Dale, Pa. 17090 Maureen Mulligan PV NOW Consultant 717-582-7484 maureenm@pa.net Submitted: March 8,2006

PV Now, the Solar Energy Industries Association (SEIA), and the Mid-Atlantic Solar Energy Industries Association respectfully offer these comments in response to the February 8, 2006 notice of the Public Utility Commission regarding implementation issues arising from The Alternative Energy Portfolio Standards Act of 2004 ("Act 213"), 73 P.S. §§ 1648.1 – 1648.8,. PV Now appreciates the opportunity to submit these Comments in response to the questions regarding cost recovery and related issues.

PV Now is a national solar industry advocacy group comprised of manufacturers and integrators in the solar PV industry, including Sharp Solar, Shell Solar, PowerLight Corporation, Schott Solar, SunPower Corporation, and Evergreen Solar. MSEIA is a trade association of solar industry professionals working in Pennsylvania, New Jersey and Delaware. PV Now and MSEIA are affiliated with the national Solar Energy Industry Association (SEIA).

Our comments will follow the Questions asked in the Commission notice wherever possible. For the most part, our comments will refer specifically to the solar requirements in the AEPS.

1. **Should Act 213 cost recovery be addressed in the Default Service regulations as opposed to a separate rulemaking? Is it necessary to consider Act 213 cost recovery regulations on a different time frame in order to encourage development of alternative energy resources during the "cost recovery period"?**

Act 213 section 3 (1) (11) addresses a process for cost recovery during and after the cost recovery period using an automatic energy adjustment clause. We feel that this mechanism would be sufficient and proper for a separate Commission rulemaking outside of the arena of Default Service regulation.

Given the relative clarity of the AEPS legislation on this issue,   PV Now does not believe that it will be necessary to address cost recovery of AEPS resources in POLR. However, there must be timely resolution of all cost recovery issues so that default providers will successfully implement the provisions of the Act. PV Now strongly supports the use of long term contracts as the primary mechanism to implement the solar requirement in the Act and would see as beneficial that once a long term contract was executed, cost recovery was assured over the life of the contract. PV Now endorses the legitimate cost recovery of default providers in meeting this requirement. More detail is provided in our answer to Question 2 below.

2. **Do the prevailing market conditions require long-term contracts to initiate development of alternative energy resources? May Default Service Providers employ long-term fixed price contracts to acquire alternative energy resources? What competitive procurement process may be employed if the Default Services Provider acquires alternative energy resources through a long-term fixed price contract?**

2.A Do the prevailing market conditions require long-term contracts to initiate development of alternative energy resources?

<u>Importance of Standardized Long-Term Contracting</u>

In order for solar to become a viable part of the Pennsylvania market, solar projects will need to have a combination of revenue streams from SRECs (solar renewable energy credits), electric bill reductions and net metering.

The Act reflects the clear intent of the legislature to bring about such a condition. However, unlike the majority of states seeking to encourage substantial solar development, Pennsylvania does not have any statewide program of upfront rebates for solar consumers. Solar project developers and customers must rely heavily on their SRECs to provide an acceptable payback period.

Relying on SRECs to develop a financial pro forma that is acceptable to banks or other lenders that finance renewable projects can be challenging. SRECs created and traded on a year to year, spot market basis provide no assurance to lenders that the revenue from SRECs will exist in future years, creating a major regulatory risk. Furthermore, these lenders have no way to predict the value of future year SRECs.

As a result, lenders normally refuse to accept any projections of spot market SREC revenue in project pro formas; where the revenue is permitted, it is heavily discounted (by 70 -90%,) effectively making their projected revenue insignificant. This in turn raises the cost of implementing the solar requirements of the AEPS and is not in the ratepayers best interest.

The best mechanism to address this reality in Pennsylvania and provide more confidence to financial institutions concerning the viability and price of long term SRECs is to incorporate long term solar contracts into POLR service, with standardized terms used by all including the number of years over which the contract is effective.

We expect significant savings to consumers can be achieved when the terms and conditions of long term SREC contracts are standardized. These benefits accrue both to POLR providers and SREC owners. POLR providers benefit from reducing the transaction costs associated with reviewing contracts, credit terms, technology decisions, and the like. SREC owners benefit because they are able to avoid the time and expense of hiring lawyers, consultants, etc. to interact with large companies. In the end, a standard contract will reduce transaction costs for all parties and lead to a more efficient, more timely, and less expensive program.

We recommend that within these standard contracts, the only terms and conditions determined by the parties would be the overall number of SRECs and the price per SREC, to be determined by the methods explained below.

Value of Standardized Long – Term Contracting

The ultimate value of long term contracts for solar energy systems installed in Pennsylvania is the ability to deliver required SRECs for use in the AEPS market at the lowest possible price. As mentioned above, in the absence of long term contracts there is only a spot market for SRECs, and financial institutions will require a very high risk premium for any money provided to finance solar energy systems. The only way to finance projects, then, will be to translate these risk premiums into higher SREC prices.

The table below shows the effects of this financial reality. The table shows the differences between likely SREC prices given a number of different contract lengths, and a likely risk premium that financial institutions will apply to projects without long term SREC contracts. When financing projects, banks will only consider SREC revenue if the revenue flow is certain. This certainty will only exist for those periods where SRECs are under contract. Banks will apply a substantial discount factor to any future non-contract SREC revenues as they determine how much debt a project can carry. Since there is not a substantial body of actual market history data from which to draw, the scenario below uses a 70% discount factor. Some solar project developers report that financial institutions discount non-contract SRECs by 100%- in other words they ignore those possible revenues. We have used a more conservative risk discount factor of 70% in the table. In other words, if a SREC owner signs a five year contract with a SREC buyer and goes to a bank to finance the project, the bank will reduce the imputed revenue from SREC sales in years 6-20 by 70%. The table demonstrates the sensitivity of the resulting SREC price to contract term. This analysis indicates that a market with long term contracting could result in SREC prices that are up to 50% less than those in a spot market.

LIKELY SREC PRICES (in bold)

Likely non-contract SREC risk premium		CONTRACT	TERM (yrs.)		
	1-3	5	10	15	20
70%	**$810**	**$665**	**$505**	**$440**	**$405**

2.B May Default Service Providers employ long-term fixed price contracts to acquire alternative energy resources?

Why Long Term Contracting Should Be Required

While the benefits of long term contracting have been described above, it is unlikely that default providers (or other SREC buyers) will choose to initially enter into long term contracts without certain regulatory assurance and encouragement.

1. The SREC market in Pennsylvania is new and unproven and thus will be seen as risky, particularly by traditionally risk adverse electric distribution companies.

2. Default providers may be concerned that their initial contracts may be later viewed as imprudent and subject to rate recovery disallowance.

Because of these factors, we recommend that minimum 15 year contracts be required for default providers subjected to the AEPS. We recommend that the PUC facilitate a process of developing a standardized form of contract that all default providers and SREC owners would use. In order to provide assurance that the prudent costs of their contractual obligations will be recoverable as provided in AEPS legislation, we recommend that the PUC review the initial long term contracts for SRECs and provide guidance and appropriate assurances to default providers regarding the cost recovery of those contract payments.

2.C. What competitive procurement process may be employed if the Default Services Provider acquires alternative energy resources through a long-term fixed price contract?

Proposed Competitive Procurement Process

We propose a procurement method that we believe will best and most simply meet the needs of all stakeholders in the process with minimal complexity and risk.

The major elements of our recommendations are as follows:

1. SRECs should be sold in a single statewide market regardless of the service territory of any particular default provider.
2. A designated administrator should manage the procurement process through a biannual SREC auction, occurring every six months.
3. A standard contract should be adopted. Terms would be consistent for all transactions. This will facilitate orderly, timely and cost effective implementation.
4. The Administrator shall establish minimal criteria for bidders in the auction. These criteria will seek to establish that potential bidders have real projects in development.
5. Separate processes would be established for procuring SRECs from large systems (above 10 kWp capacity) and small systems (under 10 KW).
6. Auctions to procure SRECs from large systems would be held every six months with volumes to be determined by the Administrator based on market conditions and the program “ramp up” requirements.”

7. SRECs from small systems would be acquired via a standard offer based on the most recent auction price for large system SRECs. The Administrator would assign blocks of capacity from small systems to the various default providers. Any small system owner would be notified of their assigned default provider and would sign a standard, simplified form of agreement showing the SREC price per year for a fifteen year contract term (or other fixed term utilized in the latest large system auction).
8. The Administrator would establish criteria for analyzing auction responses. For example, the Administrator may determine that the lowest SREC prices may be obtained from front-end loaded contracts and could establish relevant discount rates, for evaluating different proposals or the administrator may accept varying prices over the 15 years term.
9. The Administrator would establish the auction rules and procedures and conduct the auctions. One possibility would be to accept the lowest bids from large system SREC owners until the designated volume of SRECs required for that biannual period had been received. The Administrator would then use the last successful bid as the clearing price for all bids in the auction. Another alternative is to establish a "Dutch auction" process such as the one used by various states to conduct procurements for default supply.
10. All auction bids and standard offer contracts, whether above or below 10 kW, would carry reasonable project completion guarantees, in addition to being subject to uniform production verification and auditing requirements specified by the Commission or the administrator.
11. Once the winning bids were established, the Administrator would apportion SREC capacity awards as appropriate to various default providers in proportion to their load served in the State. Each default supplier would then enter into bi-lateral contracts with the designated SREC owners.
12. The Administrator would establish reasonable fees to be paid by the default suppliers to cover the costs of SREC procurement consistent with Act 213.
13. Default providers would then be given 60 days to conclude negotiations with the designated SREC owners or report to the Administrator about the reasons for their inability to sign a SREC contract. After 60 days, if the Administrator determines that the solar project will not be completed, he has the right to cancel the solar capacity award and reassign the additional capacity to the next large system auction.
14. The purchase costs of SRECs obtained through the administrated auction would be presumed to be prudently incurred and eligible for cost recovery by the default providers (subject to continued payments to the system owner over the life of the contract, or initial payment in full.)

3. **Should the force majeure provisions of Act 213 be integrated into the Default Service procurement process? Should Default Service Providers be required to make force majeure claims in their Default Service implementation filing? What criteria should the Commission consider in evaluating a force majeure claim? How may the Commission resolve a claim of force majeure by an electric generation supplier?**

3. A. Should the force majeure provisions of Act 213 be integrated into the Default Service procurement process?

The development of renewable resources in the state is highly dependent on the certainty of project developers and manufacturers that the demand represented by the legislation is sufficiently reliable to serve as a basis for major capital investments. Any practice which appears to undermine the certainty of this demand threatens the success of the standard as a whole.

Accordingly, while we continue to support the development of a fixed, transparent, and reliable standard for force majeure determinations, it is our opinion that the legislation provides sufficient flexibility as to both the schedule and methods of compliance that “force majeure” must be interpreted as having a meaning close to that of its general legal usage – that is, an event beyond the reasonable control of the regulated entities; and which the affected party is unable to prevent or provide against by exercising reasonable diligence. Such events may include weather related damage, mechanical failure, lack of transmission capacity or availability, strikes, lockouts, or actions of a governmental authority that adversely effect the generation, transmission, or distribution of renewable energy from an eligible resource under contract to a purchaser.
Beyond the scope of such traditional force majeure events, we recommend a narrow interpretation of the term.

The overarching legislative intent of the AEPS is clearly to encourage the development of new renewable generation in the state and clearly, the Legislature saw a special role and benefit of solar by distinguishing it in the law for special treatment. The steadily increasing targets of the AEPS and extensive legislative record, both demonstrate clearly the knowledge of the Legislature that the requirements in the AEPS were in excess of currently available resources, and would require new construction and development of renewable energy facilities.

The marketplace, in other words, is supposed to develop and grow in response to demand initiated by the regulated entities; a failure on the part of any default provider to make a good-faith effort to demand adequate resources to fully meet their obligations must play into the Commission’s determination of “reasonably available.”

3. B Should Default Service Providers be required to make force majeure claims in their Default Service implementation filing?

YES- see our previous comments in 3.a

3. C. What criteria should the Commission consider in evaluating a force majeure claim?

Any entity requesting a determination of force majeure should be required to provide adequate documentation of full participation in the aforementioned auctions (or other competitive solicitation process established by the Commission) for the reporting period in question. All claims of force majeure on the part of default providers relating to an inability to sign contracts with winners of the solar capacity auction must be fully documented and subject to review by the Administrator and the Commission. This documentation must include the justification for any proposals or bids not accepted.

The AEPS requirements will be well-known in advance to default providers currently in a cost-recovery period; given the ability to “bank” compliance credits in advance, a failure to make an adequate attempt to meet upcoming requirements should lead to alternative compliance payments.

A default provider should be presumed responsible for conducting sufficient advance planning to acquire its allotment of SRECs. Especially given the prudent long – term contracting mechanism we have proposed, failure of the spot or short-term market to supply a party with the allocated number of SRECs should not be considered an event outside the default provider’s reasonable control.

All default providers will be operating in effectively the same marketplace for SRECs, participating in the same auction, contracting for projects of the same technology types, in the same geographic area, to meet fixed requirements known many years in advance. This would suggest that where other default providers have proven themselves able to comply in this marketplace, adequate resources are presumptively “reasonably available” to all.

The Commission should also formally incorporate into their criteria for determining force majeure the thinking that any default provider that claims adequate resources were not available in the same marketplace which yielded adequate resources for others should be viewed by the Commission as questionable and should require a higher burden of proof. Further, force majeure must only apply to a single compliance period otherwise all resource development will cease.

3. D. How may the Commission resolve a claim of force majeure by an electric generation supplier?

In determining its means of relief for any given force majeure claim, the Commission must maintain as a central priority retaining the credibility of the AEPS. Maintaining high standards of proof and accountability for default providers will be a key determinant of the overall success of the AEPS. We recommend the following guidelines:

1. Force majeure claims should be limited narrowly to the specific resource shortfalls by Tier.

2. Any resolution of such claims should be limited to the default provider requesting relief and the reporting period in question. The separate reporting periods and separate percentages in the legislation provide natural boundaries beyond which extending relief is unnecessary and inadvisable.

3. When the Commission finds it unavoidable to provide focused relief, we would propose that this relief take the form of delaying requirements to a future reporting period. Given the robust growth of commercial renewable energy technologies, it is highly likely that any market shortage will be temporary.

4. The size of the solar AEPS requirement versus the market potential for solar in Pennsylvania indicates that there is existing potential in the State to easily meet the solar requirement. Any claim of force majeure relief must be evaluated in the context of this potential.[1]

5. Force majeure should only apply to the extent that a resource is not available. Default providers should be required to purchase all available SRECs and force majeure should be granted only for portions of a requirement that are actually unavailable or at a price above the ACP. It must be kept in mind that the solar share is a small portion of the overall requirement and an even smaller portion on Pennsylvania's electricity load.

4. Given that Act 213 includes a minimum solar photovoltaic requirement as part of Tier I, should these resources be treated differently from other alternative energy resources in terms of procurement and cost recovery?

The minimum solar requirement within Tier One does require special attention, and the legislature has made a clear determination that there is a compelling policy interest for Pennsylvania in developing solar energy resources. There are many benefits to distributed solar energy which have been recognized by the legislature. These include reduced strain on the electric grid, uniquely high displacement of inefficient and dirty "peaking" power plants, and substantial economic development and employment benefits for the Pennsylvania economy. A more detailed listing of studies quantifying these benefits is attached as Appendix One in our Comments.

The benefits of solar energy can only be captured by recognizing the financial realities of developing this resource, particularly as the industry moves to scale. We have addressed some of these issues in our response to Question Two. Another critical issue beyond the scope of those comments is the treatment of the Alternative Compliance Payment.
The Act specifies that:

> *(4) The alternative compliance payment for the solar photovoltaic share shall be 200% of the average value of solar renewable energy credits sold during the reporting period within the service region of the regional transmission organization.*

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[1] Total Pennsylvania Solar Requirements - Assuming annual demand of approximately 140 million MWh, the Standard would require approximately 2 MW of photovoltaics in the first year of the standard, and a total of approximately 30 megawatts cumulative by its 5th year.

Resource Base and Available Area – In a SRECent study performed for the Energy Foundation,(PV Grid Connected Market Potential under a Cost Breakthrough Scenario September 2004, available at: http://www.ef.org/documents/EF-Final-Final2.pdf) Navigant Consulting estimated the technical potential for rooftop photovoltaic devices in each state. The resulting estimate, which can be viewed as an upper bound on the state's rooftop solar potential, was 23,646 megawatts by 2010. In Year 5, the requirements contemplated would demand approximately .13% (less than one five-hundredth) of Pennsylvania's rooftop solar potential - omitting other opportunities such as parking structures, brownfields, etc., etc.

Global and National Manufacturing – Market survey data now shows 2004 global manufacturing of 1,254 MWp, and 2005 manufacturing upwards of 1,600 MWp.

This language requires interpretation of the term “average value” by the Commission, and a regulatory definition of how this “average value” would be calculated. This determination could prove a threshold issue for the success of the ACP, and ultimately will determine the success or failure of the solar requirement.

The legislative intent of the ACP appears to have been to provide a degree of self-enforcement, whereby within the constraints of force majeure, market forces would make compliance with the state's renewable requirements invariably less expensive than the noncompliance alternative.

In order to enable this mechanism, however, an economically valid calculation of SREC market value must be made. It is important to realize that the uncorrected market price for SRECs within the PJM service region does not currently provide an adequate proxy for this calculation. At the present time, there is limited market information within the regional transmission organization geographies that is directly applicable to Pennsylvania. The only market where there is an established value of solar RECs is New Jersey- and the New Jersey situation is very different from that of Pennsylvania.

Presumably, the true market value of a solar SREC is that price which, when coupled with upfront incentives and electrical savings, makes solar energy economically attractive to consumers. In New Jersey, the value of SRECs over the life of a system is coupled with immediate project revenue from customer rebates to reach this value threshold. In fact, for New Jersey customers, the SREC value is substantially less than the value coming from the rebates available from the New Jersey Clean Energy Program. We have calculated that the equivalent value of the New Jersey rebates and SRECs (based on actual 2005 average prices) is from $570-$668 per SREC (depending on the assumptions used.)[2] Only a portion of the value of a given project is therefore reflected in SREC payments.

This would imply that the average market *value* of Pennsylvania SRECs in 2005 would have been between 2.9-3.3 times the 2005 spot market *cost* as observed in the New Jersey market.

Although the price of SRECs is likely to decline over time, the above data does show that to meet the legislative intent of the Act, a calculation of ACP prices more sophisticated than mere spot market pricing is required.

By setting the ACP at twice the market value of SRECs, the Legislature clearly sought to drive providers into the SREC market and away from alternative compliance. Only with vigorous enforcement of an appropriate ACP will this intent be realized.

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[2] The $668 SREC resulted from an analysis that modeled a constant – payment, constant-interest stream of payments equivalent for the NJ CEP rebate using the following assumptions: solar capacity factor 13.1%, 100 KWp typical commercial system with (cumulative average $4.09/W rebate under the New Jersey Clean Energy Program rebates available through 2/1/2006, 10% Federal ITC, capital cost of $7.45/W, all cash purchase, unadjusted SREC of $200. The $570 SREC resulted from an analysis of the required revenue stream from a similar project that was necessary to achieve a 9% IRR.

Accordingly we recommend that the Commission reflect an appropriate measure of the net present value of the New Jersey Clean Energy Program rebates in the "market value" calculations required by statute.

Currently in the legislation, all Alternative Compliance Payments are directed into a special fund of the Pennsylvania Sustainable Energy Board and made available to the regional Sustainable Energy Funds under procedures and guidelines approved by the Pennsylvania Energy Board. Where SACP payments are collected, we recommend that the proceeds be directed to a dedicated account that is used by the Sustainable Energy Board to fund the development of solar projects.

5. **Should the Commission integrate the costs determined through a §1307 process for alternative energy resources with the energy costs identified through the Default Service Provider regulations? How could these costs be blended into the Default Service Providers Tariff rate schedules?**

6. **May a Default Service Provider enter into a long-term fixed price contract for the energy supplies produced by coal gasification based generation if the resulting energy costs reflected in the tariff rate schedules are limited to the prevailing market prices determined through a competitive procurement process approved by the Commission?**

7. **Should the Commission delay the promulgation of default service regulations until a time nearer the end of the transition period, as suggested by the Independent Regulatory Review Commission in its comments on the proposed regulations?**

8. **Does the Commission need to make any revisions to its proposed default service regulations to reflect the mandates of the Energy Policy Act of 2005?**

We reserve our opinion on issues 5 – 8 for the purposes of this comment period.

Benefits of Pennsylvania Solar Electricity Production

There have been numerous studies completed across the country that take different approaches to quantifying the value of renewable energy, distributed energy and distributed solar electricity. It is difficult to agree on a definitive value for solar electricity, as for the other renewables, since many of the benefits accrue to society in general or are benefits that have not been quantified in energy markets to date.

A number of the studies have been focused on California although the general range of values is applicable to Pennsylvania. For example, a study completed in January 2005[3] concluded that, "The findings of this study indicate that the value of on-peak solar energy in 2005 is between 23.1 cents and 35.2 cents per kilowatt hour depending, in large part, on the location of the solar electric systems."

A recent analysis has been completed for the California Energy Commission by Energy and Environmental Economics and the Rocky Mountain Institute[4]. This study attempted to quantify the value of distributed PV within three investor owned utility areas in California. They concluded that PV power has a premium that ranges from 17% to 37% over the average commercial customer electricity price within different utility areas. A companion study done by an independent analyst during the same CEC proceeding, calculated the PV value premium to be 50% greater than the utility price for power. [5]

A fourth study examined the value of PV power in the PJM and California markets during 2000. This study found that the value of PV was two times that of the overall cost of power in off-peak hours and up to five times as high as the on-peak energy costs in PJM. [6]

A study that examined the cost/benefit of a proposed RPS expansion is one completed in December 2004 by the Center for Energy, Economics and the Environment at Rutgers University on behalf of the New Jersey Board of Public Utilities.[7] That study concluded that the major sources of benefits from the RPS will come from economic development, job creation and

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[3] Quantifying the Benefits of Solar Power for California- A White Paper. by Ed Smelloff. January 2005 Available at: http://www.votesolar.org/tools_Quantifying Solar%27sBenefits.pdf

[4] A FoSRECast of Cost Effectiveness - Avoided Costs and Externality Adders, Prepared by Energy and Environmental Economics and Rocky Mountain Institute for the California Public Utilities Commission, January 8, 2004 Draft. Informally known as the "E3 Avoided Cost Study."

[5] Duke, Richard, Robert Williams, and Adam Payne, "Accelerating Residential PV Expansion: Demand Analysis for Competitive Electricity Markets," Energy Policy, 2004.

[6] Valuing Load Reduction in Restructured Markets- Supply Cost Curve Regressions, Market Price vs. Value of Load Reduction- Photovoltaic Case Study. By William B. Marcus, JBS Energy, Inc. November 2000 presentation.

[7] Economic Impact Analysis of New Jersey's Proposed 20% Renewable Portfolio Standard. The Center for Energy, Economic and Environmental Policy, The Edward J. Bloustein School of Planning and Public Policy Rutgers, The State University of New Jersey. December 8, 2004.

indirect contributions to the Gross State Product from local manufacturing, installation and maintenance of renewable facilities within New Jersey. This is exactly the strength that the distributed solar electricity industry brings to the table. Solar energy products will be installed in Pennsylvania by local skilled labor, supported by local sales, service and engineering expertise. The creation of the AEPS solar tranche, will encourage continued long term investment in Pennsylvania by the world wide solar industry. Increases in natural gas, coal and oil prices since November 2004 increase the net benefits shown in the Rutgers University study.

An additional set of benefits identified in the Rutgers study were related to the environmental benefits of clean energy in general, and solar electricity specifically. The Rutgers study surveyed the range of studies on the topic of environmental externalities and concluded, "Illustrative calculations using generic environmental externality adders indicate that in the year 2020 several hundred million dollars in environmental damage may be avoided by implementing a 20% RPS" [8] The general directional conclusions of the report are valid for Pennsylvania as well.

A similar conclusion that the enhanced Texas RPS (including a solar component) would provide net benefits to the citizens of Texas was made in the February 2005 Union of Concerned Scientists report, Increasing the Texas Renewable Energy Standard: Economic and Employment Benefits.[9]

A seventh study[10] identified a number of benefits of solar electricity across a number of dimensions, including locational, environmental, hedge values, security and efficiency. The conclusion of this analysis was that the value of PV power ranges from $.078- $.224/ kwh.

Another study that examined the economic impacts of a robust solar energy policy was completed in 2004 by the Renewable Energy Policy Project in their examination of the impacts of the SEIA PV Roadmap.[11]

A further articulation of the many benefits of distributed resources, including distributed solar electricity, can be found in the Amory Lovins book, Small is Profitable. [12] In that book, Mr. Lovins and his co-authors demonstrate and attempt to quantify, 207 benefits of distributed energy and energy efficiency.

These are but a few of the numerous studies that have described the direct and indirect benefits of solar electricity, many of which remain unmonetized in today's energy markets.

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[8] Ibid, page 64.

[9] Increasing the Texas Renewable Energy Standard: Economic and Employment Benefits Jeff Deyette and Steve Clemmer February 2005. www.ucsusa.org/assets/documents//clean_energy/Texas/RES_Report-02-05_final.pdf

[10] "Prepared Testimony On Itron Report On Framework For Assessing The Cost-Effectiveness Of The Self-Generation Incentive Program", by Americans for Solar Power. For California Rulemaking 04-03-017. April 13, 2005. Exhibits LSS-7 and LSS-8. Available at www.forsolar.org/documents/waterfall.pdf and www.forsolar.org/documents/Methodology%20for%20chart.pdf.

[11] Renewable Energy Policy Project's 2004 study on economic impact of SEIA's PV Roadmap. Available at:
http://www.crest.org/articles/static/1/binaries/SolarLocator.pdf
http://seia.org/roadmap.pdf

[12] Small is Profitable- The Hidden Economic Benefits of Making Electrical Resources the Right Size. Amory Lovins, et al. Rocky Mountain Institute, 2002.