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December 13, 2006

**Before the Pennsylvania Public Utility Commission**

**Implementation of the Alternative Energy Portfolio Standards Act of 2004**

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PA PUBLIC UTILITY COMMISSION
SECRETARY'S BUREAU

**Docket Number L-00060180**

**Proposed Rulemaking Order of July 20, 2006**

PV NOW respectfully offers comments on the AEPS Proposed Rules of July 20, 2006. PV Now is a national solar industry advocacy group comprised of the largest manufacturers and integrators in the solar PV industry, including Sharp Solar, SolarWorld, PowerLight Corporation, Schott Solar, Energy Innovation, Sun Edison, SunPower Corporation, Evergreen Solar, BP Solar and Conergy Group.

In addition to the issues raised by the Commission in the Proposed Final Rules, the solar industry is asking the Commission to address outstanding issues for solar implementation to provide the fairest and least cost solar implementation plan.

In particular, we seek clarification on the solar procurement process, contract standardization, bidding standards, as well as the timing and frequency of competitive bids. Alternatively, the Commission may seek to address aspects of solar implementation in a separate process or in the case of developing standard contract terms, through the existing POLR Working Group efforts. This may be necessary given there are additional guidelines to conducting a competitive bidding process not detailed in this filing.

In the context of all of our proposals, we urge the Commission to remember that unlike any other AEPS resource, solar resource development is almost totally comprised of individual customers, featuring a wide variety of classes of customer, system size, and sophistication. Further, these systems will be widely distributed statewide. The treatment of solar under the AEPS must therefore recognize the difference in this resource and contemplate these factors in designing rules for implementation, as did the Legislature in developing a separate solar share.

***To summarize our general positions:***

**Long term Contracts are Critical for Solar**

Long term SREC contracts (fifteen year or longer) are critical to making solar resources available to meet the requirements in the AEPS. The most significant decision the Commission can make to ensure that solar investments and resources are added to Pennsylvania's energy portfolio is to ensure that SREC sellers (PV system owners) have the ability to enter into long term SREC contracts that can be recovered in rates. Such contracts are necessary to secure needed project financing with a length commensurate to expected returns on investment. Action by the Commission to ensure long term contracts will also ensure that the costs of solar will be much, much lower than would otherwise be the case. If the Commission does not act on this issue, and SREC sellers must sell on a "spot" market, or under shorter term contracts, then the likelihood of meeting the solar share requirements.

**Standard Contracts Facilitate a Smooth Running Market**

PV Now also encourages the Commission to ensure that SREC contract terms are standardized to the greatest extent possible, to minimize transaction costs incurred by SREC buyers and sellers. This will also ensure that both large and small PV system owners have access to the market. Without such provisions, homeowners who install PV systems will be handicapped in financing their systems through the sale of SRECs alone.

**ACP Needs to be Set Above the 200% Average Market Value of Solar and the ACP Needs to Consider the Levelized Value of Rebates**

The Commission must also act to ensure that there is unambiguous understanding of the ACP for the solar share requirement. In the event that ACP value is based on SREC prices in neighboring states (e.g. New Jersey), this ACP calculation must account for the fact that these states may also provide up-front rebates to solar system owners. The appropriate formula for setting the ACP in Pennsylvania must include consideration of the levelized value of the up-front rebate as well as SREC value.

**Force Majeure Needs to be Defined Narrowly and Clearly and Should Rely in part on whether the EDCs and EGSs have maximized banking**

PV Now has previously raised its concern about the structure of the solar share requirements; particularly the steep "cliff" increases in the solar requirement in certain years, while other years have no defined requirement. SREC banking provides some relief here; however it is equally important that the force majeure provisions are clear in requiring electric distribution companies (EDC) and electric generation suppliers (EGS) to demonstrate prudent advance purchase negotiations in the years leading up to the stepped-up SREC requirements. What would be more desirable is for the Commission to establish five year banking for the separate solar share.

**The Solar Share is a Percent of Retail Electricity Sales, not Tier I**

The language in the draft order is unfortunately ambiguous as to whether the solar share requirements are to be calculated as a percentage of total electricity sales or as a percentage of Tier 1 electricity sales. The Commission should make it clear that the solar share percentages in the AEPS statute are intended to be calculated as a percentage of total retail electricity sales.

**<u>§75.51 EDC and EGS obligations.</u>**

**<u>Issue</u>**

This is the first time in any Commission AEPS Order that the solar photovoltaic requirement is represented as a percent of Tier 1 sales instead of the commonly agreed to percent of total retail sales.

**PV NOW Position**

Section75.51(b) (1-15) of the Proposed Final Order states "EDCs and EGSs shall acquire alternative energy credits in quantities equal to the percentage of their total retail sales of electricity to all retail electric customers for that reporting period, as measured in MWh" Contrary to the above, the solar share is here calculated as a percent of Tier I sales, reducing the final solar share by 80%.

PV Now requests the Commission change the language to reflect the original intent of Act 213, that is, that the solar share is a percent of the total retail electricity sales.

Under this interpretation, the total solar PV requirement would be reduced by more than an order of magnitude - from 858MW down to a mere 69MW over the same time period. PV Now participated in the drafting of the Act, and we can verify that this latest interpretation was clearly not the intention of the Legislature – nor is it in line with recent media and political statements on the part of all stakeholders.*(In our opinion, the attached spreadsheet at Appendix I best reflects the requirements of the solar share.)*

**§75.32 Fuel and technology standards for alternative energy sources.**

PV Now supports the Commission's inclusion of solar thermal resources in Tier I.

**§75.34 Alternative energy credit certification.**

**Issue §75.34(f)**

Alternative energy credit certification shall be verified by metered data pursuant to standards approved by the Commission.

**PV NOW Position**

PV Now supports the use of metered data or other approved technology for all solar applications regardless of system size. PV NOW/MSEIA stands ready to offer the Commission technical support as necessary in the development of metering standards.

**§75.35 Alternative energy credit program administrator.**

**Issue**

The conditions under which solar will be procured are not clearly defined. Further clarification for procuring supply will enable the solar market to develop with the level of confidence needed to attract significant investment.

**PV NOW Position**

PV Now requests the Commission take an active role in shaping the procurement process for solar, which we view as separate and distinct from that in place for other AEPS resources. It is critically important that the procurement process provide transparent access to standard long term SREC contracts for sellers large and small.

We have included a detailed, though not completely comprehensive, discussion of one way to approach a solar procurement process. While we acknowledge that there are many ways it can be structured, we think our approach represents a model under which many solar business models can function.

This model can ensure that the SRECs are being traded at a price determined by market forces, and does not exclude the opportunity for bilateral contracts once the market clearing price is set. Towards this end, PV NOW recommends the following for consideration:

**Solar Procurement Process Recommendations**

PV NOW has learned valuable lessons by participating in the New Jersey and Colorado solar markets that leads us to recommend a statewide procurement process as the best mechanism to ensure all ratepayers have equal access to a statewide framework of standard prices and contract terms. There are several reasons for a single statewide process:

- With individual projects potentially eligible under several simultaneous RFPs from differing utilities, it is difficult to predict which auctions or other procurement processes to bid a project into, without knowing if a bid in another eligible service territory has been accepted.

- Given differential pricing across various utility territories, if the competitive bidding process is not statewide, it is likely that a majority of the projects will be built in one or two service territories instead of across the state.

- Multiple competitive bidding approaches are a recipe for inequitable administration, lead to an insecure market environment for industry and financial markets and are a challenge for the Commission to oversee.

- Suppliers of solar energy could number in the thousands. Only a single, unified process can provide the clarity and simplicity required to serve such a large number of providers without undue administrative burden. It would utilize standardized contracts and qualified bidders, which would reduce administrative overhead costs.

- The Commission's burden of tracking many different procurement processes for solar would similarly be reduced, and the competitive bid would result in a prevailing market price for solar supply.

- This approach would also serve to encourage businesses to aggregate small customers, greatly increasing efficiency. Therefore, we recommend the Commission directly administer, (or contract for the administration of,) a single competitive bid process with standard rules and prices.

**Treating Large and Small Producers Equitably**

In order to have a fully developed, diverse solar market, PV NOW recommends two separate processes for procuring SRECs; one for large systems (above 10 kW capacity) and one for small systems (under 10 KW). This will ensure that solar development takes place across all customer classes, maximize job creation and business opportunities, and provide equitable opportunities for residential and other small system development.

SREC targets could be set for both large and small systems. Small systems' SRECs would be available via a standard contract based on the most recent price determined for large system SRECs. Upon purchase of the small system owners' SRECs, standard, simplified contracts listing the SREC price for each year of the contract would be signed. Once the winning bids are established, the utility would apportion SREC capacity awards in proportion to the required load in their service territory.

**Solar Long Term Conditions for Contracts**

The ultimate value of long term contracts with standard conditions is delivery of required SRECs at the lowest possible price. Greater supplier risk translates to higher prices. Long term contracts reduce the price of SRECs because they reduce the financing costs of solar projects.

Table I shows the differences between SREC prices given a number of different contract lengths. A conservative risk premium of 70% can be applied by financial institutions to hedge against short term contracts. Banks will apply a substantial discount factor to any future non-contract SREC revenues as they determine how much debt a project can carry. Some solar project developers report that financial institutions discount non-contract SRECs by 100%, (effectively valuing future on-contracted revenues at zero due to regulatory risk.). [1] Banks will not likely finance projects at all based on the spot market.

[1] A conservative risk premium of 70% can be applied by financial institutions to hedge against short term contracts. Banks will apply a substantial discount factor to any future non-contract SREC revenues as they determine how much debt a project can carry. Some solar project developers report that financial institutions discount non-contract SRECs by 100%, (effectively valuing future non-contracted revenues at zero due to regulatory risk.)
We have used the more conservative 70% discount rate. 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.

The key value of long-term contracts for solar is the ability to deliver the SRECs required for each year of the AEPS compliance at the best possible prices. SRECs created and traded using short contract terms, provide no assurance to lenders that the revenue from SRECs will exist in future years, creating regulatory and financial 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. Even when such revenue is recognized, it is heavily discounted (by 70 - 90%,) effectively making projected revenue insufficient to support reasonable financing costs.

**TABLE I**

**LIKELY SREC PRICES AT VARIOUS CONTRACT TERMS**

| | | CONTRACT | TERM (yrs.) | | |
|---|---|---|---|---|---|
| Years | 1-3 | 5 | 10 | 15 | 20 |
| Price | **$810** | **$665** | **$505** | **$440** | **$405** |

While the benefits of long term contracting have been described above, it is unlikely that EDCs or EGSs will choose to initially enter into long term contracts without certain regulatory assurance and encouragement.

**PV NOW's Position on Standard Contracts**

We ask the PUC to develop standard contracts that would include price, specify the contract length and in addition should carry reasonable project completion dates; agree to uniform production verification and auditing requirements specified by the Commission. This will facilitate orderly, timely, cost effective implementation of solar by reducing transaction costs.

**§75.56 Alternative compliance payments**

**Issue**

At 75.56 (b)(1)states the ACP for solar must be set at 200% of the average value of solar renewable energy credits sold during the reporting period in the RTO control area.

**PV NOW Position**

The ACP provides a safety valve and effective price cap on REC prices. Absent extraordinary circumstances, this relief should be all that is necessary or available to administer the program.

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, 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 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.) 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 *costs* 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.

The AEPS rule should make clear that the "average value" used in this calculation should include not only the SREC value received by solar project owners, but also the levelized value of capital rebates of the New Jersey Clean Energy Program received by those project owners. This would reflect the market value of the SREC calculations in order to determine the value of the ACP as required by statute.

| Calculating "Average Value" based on NJ SREC Price, plus NJ Capital Rebate | |
|---|---|
| | |
| **Actual NJ Historical Data** | |
| Average NJ SREC Price in 2005 ($/MWh) | $ 201 |
| Rebate for 100 kW project ($/W) | $ 4.09 |
| Average Annual SRECs per kW Capacity (MWh/kW/year) | 1.12 |
| **Financial Assumptions** | |
| Solar Project Owner's Discount Rate | 8% |
| Number of years levelized | 20 |
| **Summary of Results** | |
| Equivalent Levelized Rebate payment ($/W/year) | $0.42 |
| Equivalent SREC Value of Rebate ($/MWh) | $466 |
| Average NJ SREC Price in 2005 ($/MWh) | $ 201 |
| **Total Equivalent SREC Value ($/MWh)** | **$ 667** |

Issue at §75.56 (e)The proposed regulations would direct alternative compliance funding to the four statewide sustainable energy funds; however to date these funds have not focused on direct incentives for deployment, but rather on loan programs whose impact is less direct.

**PV NOW Position**

PV NOW requests that the Commission direct any ACP solar payments received by the funds to solar rebates. Rebates will have the most immediate impact on deployment of clean energy systems as intended, and are particularly valuable in Pennsylvania since there is no statewide solar rebate program. PV NOW also encourages the Sustainable Energy Fund to look at production incentives or other matching opportunities to best leverage the benefit to growing the solar market.

**§75.57 General Force Majeure**

**Issue**

The scope of Force Majeure could be broadly interpreted and does not specifically provide definitive guidance on conditions for Force Majeure claims.

**PV NOW's Position**

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 making major capital investments in Pennsylvania. Therefore, a clear and narrow Commission interpretation of Force Majeure is necessary.

We support the Commission's language that "The Act's market price standard for solar photovoltaic alternative compliance payments would appear to preclude a price cap for related Force Majeure determinations. Rather, the Commission will limit itself to reviewing the availability of solar photovoltaic resources when making Force Majeure determinations for this resource," as opposed to giving the Commission the ability to impose economic considerations not traditionally associated with Force Majeure claims.

**Determination of Force Majeure**

We are concerned that the force majeure mechanism contemplated by the Commission goes beyond the standard described in the legislation, potentially reducing utilities' incentive to comply and introducing serious uncertainty into the market. This may discourage the entry of new project developers. Since renewable energy projects will only be created in response to demand for credits which are not already in the market, the prospect of a Commission pre-determination will act as a disincentive for utilities to invest the time and effort necessary to achieve full compliance.

Instead, we feel it is appropriate to require utilities to make their maximum effort to come into compliance with the standard, permitting them only to apply for force majeure as necessary *for individual reporting entities,* and subject to the criteria outlined below.

In addition to greater specificity on conditions appropriate for force majeure, we also would like the Commission to specify the level of reporting expected to support that a "good faith" attempt at procurement has been made.

***No Advance Determination or Reduction of the Solar Requirement***

The Commission should not take it upon itself to determine in advance whether the market will provide adequate renewable energy for compliance, as the prospect of any such adverse determination will have distorting effects on the motivations and assumptions of participants in the market for renewable energy. Further, the Commission should not reduce the solar requirement; that would be the General Assembly's responsibility should that be needed.

The mechanism of the AEPS is to encourage developers to propose new projects, incorporating projected revenue from credit sales to utilities as necessary – *not* to provide additional revenue streams to projects that would already be in existence and visible to the Commission's mechanism of estimating available supply *before* a reporting period began. In effect, the Commission is proposing to determine balance of supply and demand in a market before a single transaction has occurred.

In other words, the Commission is proposing by its general force majeure language to nullify a mechanism for constructing new generators, for the reason that those new generators do not already exist. This confounding logic removes all responsibility on the part of regulated utilities to make any effort to comply, instead placing all responsibility on developers to build projects in advance of requirements.

To propose, as the Commission does in proposed **§ 75.57 (a)**, to provide relief from the requirement *before such requirement has provided any signal to the marketplace*, inverts the mechanism of the AEPS, and would render it entirely ineffectual.

Rather, it should only make such determinations on a case by case basis in response to a petition from an affected utility, associated with its compliance report. This would appropriately remove force majeure from any entities' projections and planning and instead placing it in its appropriate role as a means of relief from extraordinary circumstances.

*Meaning of Force Majeure*

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.

All force Majeure criteria must be transparently and explicitly incorporated into the Commission's rules. 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 would in out years be in excess of currently available resources, and would require new construction and development of renewable energy facilities. This development will require substantial proactive effort on the part of the regulated entities.

In short, it is the role of the entities complying with the AEPS to undertake actions to *create* a market having adequate credits to meet their demand, not to throw up their hands should such a market fail to materialize.

***General Force Majeure***

Any entity requesting a determination of force majeure should be required to provide adequate documentation of their attempts to purchase or self-generate credits for the reporting period in question, and all previous reporting periods, according to all criteria determined beforehand, by the Commission.

We offer the following solar criteria for determining force majeure, as well as proposed methods of relief that can operate to protect regulated entities from the unforeseeable, and limit the potential cost impacts. Questions on which the procurement effort should be judged may include, but should not be limited to:

***1. Interim Compliance and Progress Towards Compliance***

The AEPS requirements contain marked jumps in compliance in individual years, particularly for the solar requirement. Requirements do not increase gradually in each individual year, but rather take the form of a limited number of "mile markers" during the life of the standard.

In coupling these periodic "mile markers" with generous provisions for advance "banking" of compliance credits, it was the clear intent of the Legislature to provide the utilities with the maximum flexibility to determine their own rate of compliance uptake.

However, it is neither appropriate nor reasonable to assume that the intent of the legislation was for regulated entities to procure no renewables whatsoever in the majority of years, only to massively increase procurement immediately prior to compliance years. The reality of market development is such that such a model would be entirely unworkable.

In short, no regulated entity should be permitted force majeure relief unless they can demonstrate adequate and continuous progress towards the AEPS requirement "mile markers" in all previous years. This progress requirement should apply particularly to those utilities which only fall under compliance requirements in out years, and must include a recognition that credit procurement must occur with significant year on year growth to ensure future compliance.

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 non-recoverable alternative compliance payments.

An EDC or EGS provider should be presumed responsible for conducting sufficient advance planning to acquire its allotment of SRECs. Given the realities of developing a new industry and market in the state, and 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.

### *2. Comparison to Other Providers*

All entities will be operating in effectively the same marketplace for SRECs, 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 force majeure does not apply, other providers have proven themselves able to comply in this marketplace. Therefore adequate resources are presumptively "reasonably available" to all.

A situation can be imagined where one utility experiences a market limitation which did not extend to others. However, the Commission should formally incorporate into their criteria for determining force majeure the doctrine that any provider who claims adequate resources were not made available in the same marketplace which yielded adequate resources for others should carry a higher burden of proof.

### 3. *Competitive Bid or Self Build Criteria*

All entities should be required to demonstrate that they made an effort to purchase credits in the market, or to construct renewable generation facilities, adequate to their credit requirements. In the case of credit procurement efforts, these criteria could include, among others:

- Terms – RFP or standard contract offer terms should be evaluated in the context of their reasonableness, in the context of other requests in the market. (In fact, preferably the Commission or the Administrator would standardize such terms beforehand as detailed elsewhere in our comments.)
- Distribution – did the regulated entity make an adequate effort to publicize their RFP to developers and customer-generators who would be potentially interested?
- Timing – RFPs and standard offer contracts should be made available a minimum of one year in advance of requirements, with adequate time to respond.
- esponse Volume – how many respondents were there to the request?
- Pricing - Was an adequate volume of credits made available at pricing less than the ACP?
- Contract Length – Were attributes contracts of an adequate length to attract financing?
- Partial Requirements - Did the utility purchase all credits available to it under the ACP, before seeking regulatory relief?

and in the case of self – construction:

- Was there due diligence in the preparation and execution of project construction?
- Was there adequate planning for alternative credits in the event of project non-completion or underperformance?

Of course, in the case of a single statewide competitive bid process as we have suggested, the satisfaction of these requirements would no longer be the responsibility of the individual EDCs and EGSs – participation in the single process would be presumptively a good faith effort towards credit acquisition. This would reduce not only the uncertainty of utilities as to whether their bid process would be successful and meet Commission standards, but also the responsibilities of the Commission or its designated Administrator to make adequate verification of the above criteria.

***Force Majeure Consideration: Overall Resource Potential***

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 overall potential.[2]

**§75.59 Alternative Compliance Payments**

**Issue**

Should the EDCs and EGSs be allowed cost recovery on ACP?

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[2] Total Pennsylvania Solar Requirements - Assuming annual demand of approximately 140 million MWh, the Standard would require approximately 18 kW of photovoltaics in the first year of the standard, and a total of approximately 20 megawatts cumulative by its 5th year.

Resource Base and Available Area – In a recent 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.

Global and National Manufacturing – Market survey data now shows 2005 manufacturing upwards of 1,600 MW of solar.

**PV NOW Position**

In general we agree with the Commission's determination that the ACP was intended as a penalty provision, and that it should be administered as a non-recoverable fee. This will serve as a further incentive for the utilities to act in good faith supporting the development of a robust and competitive solar market in the state if those fees are not recoverable.

As above, we do feel that the only exception to this general policy should be in the case of a legitimate and verifiable Force Majeure claim, according to the narrow and exceptional criteria we have proposed.

**§75.41 Banking of alternative energy credits.**

**Issue**

The "step function" in the Act's requirements may make it difficult to meet some years of the requirements when there are limits on banking.

**PV NOW's Position**

The AEPS requirements contain marked jumps in compliance in individual years, particularly for the solar requirement. Requirements do not increase gradually in each individual year, but rather take the form of a limited number of "mile markers" during the life of the standard. In coupling these "mile markers" with advanced "banking" of compliance credits, it was the clear intent of the Legislature to provide the utilities with the maximum flexibility to acquire the necessary credits. However, it is neither appropriate nor reasonable to assume that the intent of the legislation was for regulated entities to procure no renewables whatsoever in the majority of years, only to massively increase procurement immediately prior to compliance years. The reality of market development is such that such a model would be entirely unworkable.

Accordingly, we request that the Commission allow the utilities maximum flexibility in banking and forward borrowing of renewable energy credits although the most critical action the Commission could take to rectify the two year banking limit with the large jump in the requirement

Accordingly, we request that the Commission allow the utilities maximum flexibility in banking and forward borrowing of renewable energy credits although the most critical action the Commission could take to rectify the two year banking limit with the large jump in the requirement every four years would be to develop longer solar banking requirements that compliment the realities of the steep incline in the solar requirement in the Act. We recommend five year banking for solar.

Submitted by: David Hochschild
Executive Director
PV NOW
December 13, 2006

David Hochschild

Attachment

## Appendix I PV NOW

## PV NOW Appendix I
## SDF Solar Share Table

| | Tier I | | Solar Share | | Tier II | | Total | |
|---|---|---|---|---|---|---|---|---|
| | MWHs | MWs | MWHs | MWs | MWHs | MWs | MWHs | MWs |
| RY 2007 | 21,814 | 8 | 19 | 0.02 | 61,133 | 9 | 82,966 | 17 |
| RY 2008 | 87,658 | 33 | 76 | 0.07 | 245,654 | 35 | 333,388 | 68 |
| RY 2009 | 244,770 | 93 | 159 | 0.15 | 514,351 | 73 | 759,281 | 167 |
| RY 2010 | 948,345 | 361 | 493 | 0.47 | 1,594,049 | 227 | 2,542,888 | 589 |
| RY 2011 | 3,028,127 | 1,152 | 20,630 | 19.5 | 6,300,765 | 899 | 9,349,522 | 2,071 |
| RY 2012 | 5,526,705 | 2,103 | 32,242 | 30.4 | 9,847,278 | 1,405 | 15,406,225 | 3,539 |
| RY 2013 | 6,416,511 | 2,442 | 32,730 | 30.9 | 9,996,323 | 1,426 | 16,445,564 | 3,899 |
| RY 2014 | 7,332,076 | 2,790 | 33,226 | 31.3 | 10,147,749 | 1,448 | 17,513,051 | 4,269 |
| RY 2015 | 8,274,009 | 3,148 | 33,729 | 31.8 | 10,301,595 | 1,470 | 18,609,334 | 4,650 |
| RY 2016 | 8,855,482 | 3,370 | 421,690 | 397.8 | 13,831,419 | 1,974 | 23,108,590 | 5,741 |
| RY 2017 | 9,846,143 | 3,747 | 428,093 | 403.9 | 14,041,456 | 2,004 | 24,315,692 | 6,154 |
| RY 2018 | 10,864,982 | 4,134 | 434,599 | 410.0 | 14,254,856 | 2,034 | 25,554,437 | 6,578 |
| RY 2019 | 11,912,660 | 4,533 | 441,210 | 416.2 | 14,471,675 | 2,065 | 26,825,545 | 7,014 |
| RY 2020 | 12,989,853 | 4,943 | 447,926 | 422.6 | 14,691,972 | 2,096 | 28,129,751 | 7,462 |
| RY 2021 | 13,642,502 | 5,191 | 909,500 | 858.0 | 18,190,003 | 2,596 | 32,742,006 | 8,645 |