CITIZEN POWER

Public Policy Research Education and Advocacy

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Implementation of the Alternative	}	Docket No. M-00051865
Energy Portfolio Standards Act of 2004	}	

REPLY COMMENTS OF CITIZEN POWER

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1) Time Tables for Tier Obligations

The time table for Tier I and Tier II implementation is ambiguous.

Section 3.(a)(1) states:

> "FROM THE EFFECTIVE DATE OF THIS ACT through and including the 15th year after enactment of this act, and each year thereafter, the electric energy sold by an electric distribution company or electric generation supplier to retail electric customers in this Commonwealth shall be comprised of electricity generated from alternative energy sources, and in the percentage amounts as described under subsections (b) and (c)."

Based on this, the effective date of the act (in February 2005), and the reporting period (June 1 through May 31), it seems that Year 1 of the Act would be from June 1st, 2005 through May 31st, 2006.

However, Section 3, subsection (b) states that the Tier I and solar photovoltaic shares are to commence "two years after the effective date of this act." Does this mean June 1st, 2007? If so, how does this affect the time table leading up to the 15th year? The Act clearly states that by the "*15th year after the effective date of this subsection*," 8% of electric energy sold must come from Tier I resources. Does this mean that the 15th year is 2019-2020 or 2021-2022?

The Tier II time table is outlined in Section 3, subsection (c) – a different subsection than where the Tier I time table is defined. Any two-year delay used for Tier I would not apply to Tier II. Presumably, Tier II would start in the first year after enactment of the Act (2005-2006), as outlined in subsection (a), so that the 10% Tier II goal in the 15th year would line up with the 15th year mentioned in subsection (a).

Clear time tables ought to be published as soon as possible to bring clarity to this matter, especially if any requirements will be starting this year.

2) Delayed Obligations for Load-Serving Entities with Temporary Exemptions from the Act's Requirements

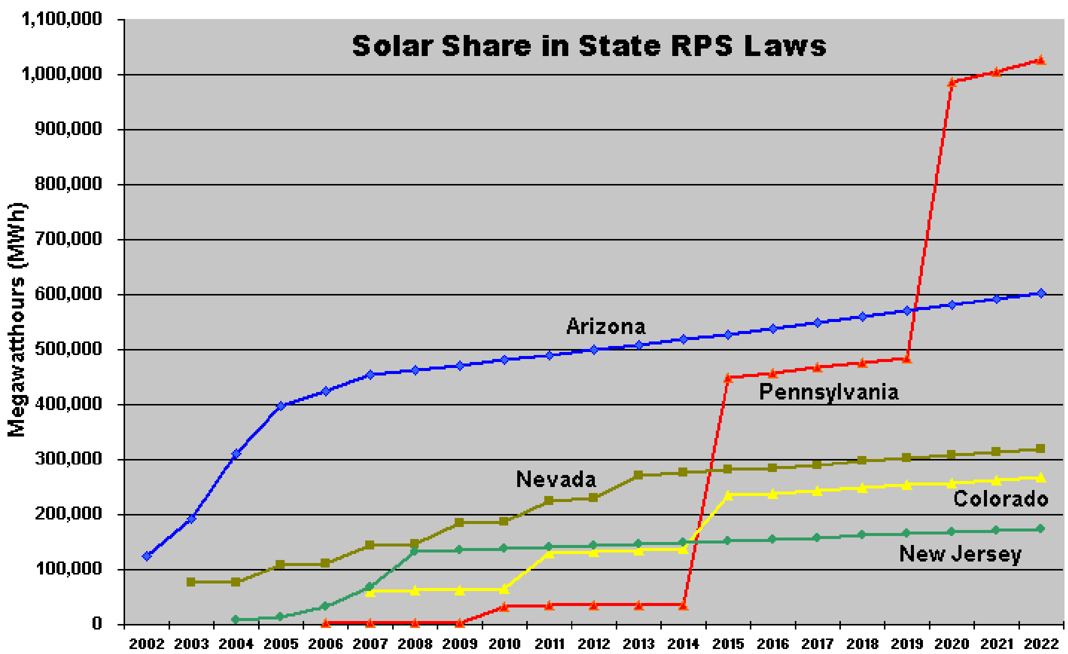
The Energy Association provided comments seeking a further delay in the onset of the obligation for load-serving entities under fixed price generation plans. The Act is already overly generous in delaying the obligation in Section 3 (d) ("Exemption during cost-recovery period"). It would further water down the impact of the Act to allow any further delay in applying the alternative energy obligation.

3) Solar Share Time Table

As stated in comments by the Sustainable Development Fund, the solar photovoltaic share has a very rough time table that is begging for force majeure. They state:

"It is important to smooth out these numbers so the industry builds smoothly. The large jumps in Year 5 and Year 10 are force majeure waiting to happen."

As is demonstrated in the chart below, the shock is much more significant in Year 10 and Year 15 than in Year 5. Effort should be made to stick to the goals in the Act, while smoothing out the obligation to avoid unnecessary force majeure conditions and to follow in the footsteps of other states where they have adopted much smoother time tables for solar shares.



4) Geographic Scope

Section 4 states:

> "Energy derived only from alternative energy sources inside the geographical boundaries of this Commonwealth or within the service territory of any regional transmission organization that manages the transmission system in any part of this Commonwealth shall be eligible to meet the compliance requirements under this act."

This language seems pretty clear and would indicate that energy from anywhere in PJM or MISO could be used to meet the Act's requirements. No limitation exists in the Act that would apply this clause only to Penn Power or other territories that don't fall within PJM. The fact that some territories (Orange and Rockland) don't fall within PJM *or* MISO (or any FERC-recognized RTO) would indicate that this clause enables them to obtain power from anywhere within PJM or MISO, but not from an area that isn't covered by a FERC-recognized RTO.

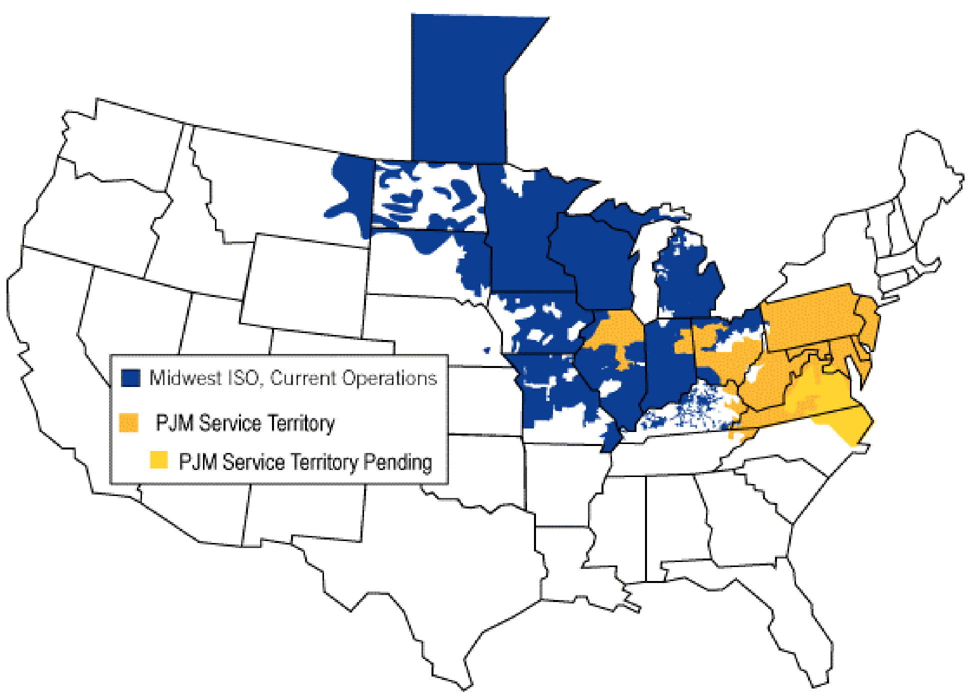
The language in the Act regarding a "regional transmission organization that manages the transmission system in any part of this Commonwealth" is used a total of four times in the Act, so it is clearly not a mistake.

Several comments were submitted arguing that only Penn Power should be permitted to draw from MISO and that the portion in the Orange and Rockland territory should be permitted to draw resources from NYISO. Another comment about geographic scope was submitted by PennFuture, arguing that the geographic scope of PJM should be limited to the geographic scope of the "PJM service area as it existed on November 30, 2004 when the Act was signed into law."

The Commission must clarify:

- whether the geographic scope of PJM for the purposes of the Act is static or whether it is dynamic, growing as the scope of PJM expands
- whether resources in MISO are available to all market participants or only to Penn Power
- whether resources in NYISO (not a FERC-recognized RTO) are available to market participants in the Orange and Rockland territory (or to any others)

If the geographic scope is expanded to include MISO for all market participants, this would dramatically change the economics, enabling Tier I to be substantially affected by the wind, landfill gas and hydropower resources of MISO. Tier II would also be substantially affected by the large hydropower resources of MISO.



5) PJM's Generation Attribute Tracking System (GATS) is Insufficient to Meet the Act's Requirements

The Act requires certain minimum obligations from any independent entity chosen to serve as the alternative energy credits program administrator:

> (2) The commission shall approve an independent entity to serve as the alternative energy credits program administrator. The administrator shall have those powers and duties assigned by commission regulations. Such powers and duties shall include, but not be limited to, the following:
>
> (i) To create and administer an alternative energy credits **certification**, tracking and reporting program. This program should include, at a minimum, a **process for qualifying alternative energy systems** and determining the manner credits can be created, accounted for, transferred and retired.
>
> (ii) To submit reports to the commission at such times and in such manner as the commission shall direct.

PJM has stated in their comments that they are **not willing to perform certification duties** as required of an alternative energy credits program administrator under the Act:

> PJM stresses that it does not intend to perform the verification of eligible resources function as part of GATS. GATS is a database tracking system, and would not perform a verification of eligibility function. In other words, GATS would not verify that a particular generator would be eligible to satisfy Pennsylvania Tier 1 or Tier 2 AEPS requirements. PJM would expect the Pennsylvania Commission to verify whether particular generators would be eligible to satisfy Pennsylvania's Tier 1 or Tier 2 RPS requirements.

If PJM is unwilling to perform the duties required of the alternative energy credits program administrator, they should not be chosen for such a role, as doing so would violate the Act.

It may be more appropriate for the Commission to **facilitate the creation of a new non-profit entity** that would operate independent of the Commission and of PJM, but which would rely heavily on the PJM GATS in order to reap the benefits that GATS could provide, such as the prevention of some forms of double-counting.

Unlike PJM, this new entity would have to be **willing to sign contracts** with the Commission. This seems necessary so that the program administrator would be legally accountable to the Commission.

PJM also says of its proposed GATS database that it "is not intended to establish any **legal title or ownership to certificates** or the underlying attributes they represent." If GATS doesn't establish legal title and ownership to certificates, what mechanism will do so? The credit trading market could possibly be streamlined by providing such an ownership mechanism through the new non-profit program administrator that would be set up to meet the requirements of the Act.

In discussing credit ownership, PJM points out that they will not be **determining the initial ownership of credits** that are generated. They state: "As MWhrs are generated within the PJM system, certificates will be created and placed into the generators' GATS accounts without prejudice to which entity is the owner of such certificates for other purposes." If this is the case, how will credits be traded, transferred or sold if the initial owner isn't determined? These issues need to be resolved (more on this topic below).

PJM also stated, regarding **"behind-the-meter" generation**: "PJM will not assume any responsibility for verification or accuracy of the supplied data." Again, if PJM will not do this, who will?

Credit pricing disclosure: As the Act requires, the cost of alternative energy credits – as well as other information pertaining to their creation and trading – must be made fully available to the public and to all market participants. Claims that this will somehow "chill" the market for renewable credits are unfounded and are based on the false assumption that this sort of information isn't already available to many market participants.

6) GATS & Double-Counting

The GATS database is being designed to guard against some important types of double-counting. These features need close attention and should be strengthened through the regulation and enforcement that would be needed to complement the protections provided by GATS.

In section 8 of our initial comments in this docket, we outlined the need to protect against forms of double-counting not specifically addressed in the Act. This includes the need to protect green pricing programs by preventing double-counting with them. It also includes the need to prevent alternative energy credits from being disaggregated, with various emissions attributes being sold separately into specific attributes markets.

It's worth pointing out that, in addition to the National Association of Attorneys General and the Center for Resource Solutions' Green-e program (cited in our initial comments on this topic), Community Energy and PJM also commented in support of protections against these forms of double-counting.

In the case of PJM, they state that "the GATS database will also support clean/green energy products offered for retail sale." To the extent that such sales are tracked, this will prevent this form of double-counting. The definition of "reserve account" in the PJM GATS document also ensures that double-counting with voluntary green pricing programs will be prevented, as long as the third-party sales are reported in GATS.

> *Reserve Account:* A GATS sub-account established by any market participant that allows the market participant to sell certificates directly to retail customers or export certificates out of PJM. Reserve Accounts are not restricted to "renewable" resources. In order to transfer certificates into the reserve account, the account holder must demonstrate that certificates were sold to a third-party in a good faith, arm's length transaction for reasonable value. Once certificates are in the reserve account, they cannot be counted in the residual mix calculation at the end of the certificate transaction period. These certificates will not appear on a disclosure label and cannot be used for RPS compliance. Reserve account transactions will be public as to transacting parties to ensure transparency.

The GATS system seems to have the right design to ensure protection against double-counting with voluntary markets, however, it seems to lack an enforcement mechanism. What if a company sells attributes as green power and doesn't report them to GATS to be placed in a reserve account? What mechanisms are in place to legally bind companies to report this and place attributes in reserve? What are the consequences of not doing so? What sort of reporting requirements are necessary to detect this form of consumer fraud?

Similar questions should be asked about sales into emission-specific attributes markets. PJM's GATS is intended to protect against this form of double-counting as well. PJM's GATS document uses the following relevant definitions:

> **Attribute:** a characteristic of a generator, such as location, vintage, **emissions output**, **fuel**, state program eligibility, etc.
>
> **Certificate:** represents **all attributes** associated with each MWh (or smaller increment) generated whether bundled or unbundled, traded or not traded.

By defining a certificate as representing ***all attributes*** and by considering emissions output and fuel to be among the attributes, PJM is taking the position that agrees with the National Association of Attorneys General, Green-e and others in guarding against the consumer fraud associated with double-counting of emissions attributes.

In PJM's GATS paper, they specifically state that: "certificates cannot be disaggregated into their individual attributes and traded separately." While the intentions are good, specific regulations are necessary and must be backed up by monitoring and enforcement mechanisms.

In ARIPPA's comments, they attempt to argue that double-counting of emissions attributes should be allowed:

> Act 213 is intended to establish a trading program in "alternative energy credits" that is distinct from the underlying generation, and distinct from

other attributes associated with that generation, such as emission allowances for NOx or SO2.

Such a conclusion is outside the mainstream and would be considered consumer fraud or double-counting by several organizations, such as those mentioned above. In trying to defend their argument, ARIPPA fails to provide any justification for allowing sales of emissions attributes separate from the sales of the alternative energy credits that incorporate those attributes.

ARIPPA makes statements such as "suggestions that alternative energy credits already are bundled with the underlying generation would be erroneous." Their argumentation revolves around this point – a point that is not in dispute. Of course alternative energy credits are separate from the underlying energy. This doesn't support their conclusion that emissions attributes can be removed from alternative energy credits and sold separately from them.

7) Initial Ownership of Alternative Energy Credits

As FirstEnergy points out in their comments, Alternative Energy Credits (AECs) are an invention of the state; therefore the state has power to decide who initially owns them. There is a need for regulations to determine the initial owner of AECs in at least the following four situations:

- Existing Non-Utility Generators (NUGs) under power purchase agreements

  As FirstEnergy points out in their comments, the New Jersey Board of Public Utilities ruled that power purchasers own the renewable energy credits from NUGs. This practice makes sense as long as the premium cost of the power is covered in the power purchase agreement (PPA). For the PURPA contracts, this seems to be the case. However, for the newer PPAs, such as Exelon's purchase of power from several new wind farms in the Commonwealth, the premium is *not* covered in the PPA, as evidenced by the need for a voluntary green pricing market to cover the premium (through Community Energy's sale of wind certificates).

  Regulations should be adopted that ensure that the initial owner of the credits from NUGs is the power purchaser *if* the PPA covers the premium. If the premium is not covered in the PPA, the initial owner of the credits should be the NUG owner. The Commission might consider basing such a decision simply on whether the PPA is a PURPA contract.

- Energy Efficiency / Demand-Side Management

  The initial owner of credits from any sort of demand reduction project should be based on who made the investment. In some cases, the investment may be shared between a load-serving entity and a customer. In these cases, the initial ownership of the credits should be split proportionally, based on the amount of investment made by each party.

- Net-metering

  In discussing net metering, Native Energy commented that "a customer-generator that is eligible for net metering shall own the renewable energy attributes produced by the system and may trade or sell the attributes or may apply for REC's." If the customer-generator made the investment, then this makes sense. In cases where some entity other than the customer-generator makes the investment, the credits should be allocated proportionally, based on the amount invested.

- Power Developed through Alternative Compliance Payments

  Alternative Compliance Payments (ACP) are to be used for the development of alternative energy generation. The ACP money used to invest in this new generation is money that otherwise should have been used directly to meet the AEPS obligation through the purchase of alternative energy credits. If the amount invested by the Sustainable Energy Funds to create the new alternative energy generation is sufficient to cover the premium associated with that generation, then alternative energy credits should not be created at all from the new generation. Creating alternative energy credits from such facilities would amount to double-counting (a form of double-counting that PJM's GATS database isn't designed to address). If the amount invested by the Sustainable Energy Funds isn't sufficient to cover the premium associated with the power generation, then credits should be created in proportion to the amount necessary to cover the uncovered premium cost of the power. Initial ownership of the credits should go to whichever entity made the investment and took the market risk associated with the project's development.

8) Competition

We support the comments by the Office of Consumer Advocate and the Office of Small Business Advocate with regards to the price of electricity and credits, ensuring that purchases of electricity or demand reduction are done through a competitive procurement process. We also support the comments filed by the Office of Small Business Advocate regarding the sale of credits and blended prices.

9) Force Majeure & Tier Alteration

ARIPPA makes the self-serving argument that a potential solution to force majeure conditions is to increase the size of Tier II in order to make up for shortfalls in Tier I.

Pennsylvania is the only state with a dirty tier (Tier II) that is larger than the supposedly clean tier (Tier I). Pennsylvania is also the only state to include fossil fuels in an otherwise "renewable" energy law.

Through the legislative development of the Act, any legislative intent to expand Tier II has already taken place. Tier I was nearly cut in half and Tier II was tripled. The Tier I share went from 15% by 2020 (in a house draft amendment that never surfaced) to 12% in the first of three amendments made to SB1030, to 10% in an amendment made 6 days later to 8% in the final version adopted the same week. At the same time, the Tier II share grew from 3.2% to 5% to 10% in the same 8-day span leading up to the Senate vote.

Other states, such as New Jersey, Connecticut, and Maryland allow overlaps in Tiers so that Tier I or II can be used to meet the Tier II requirement, but not vice-versa.

The objective of the AEPS isn't to equalize Tier *prices*, as ARIPPA claims. The entire concept of tiers is in recognition that the technologies involved have different prices associated with them. Tier II is already larger than Tier I, so any equalization arguments should flow in the other direction.

10) Force Majeure & Alternative Compliance Payments

Exelon argues that there should be a threshold market price of new construction, above which companies wouldn't have to buy alternative energy credits. This is what the alternative compliance payment (ACP) concept is for. ACPs exist to serve as a fine or penalty to motivate market participants towards compliance with the Act. With the exception of the ACP for the solar share in Pennsylvania's AEPS, ACPs also serve the function of setting the threshold market price that is functionally a ceiling on the cost of alternative energy credits.

Exelon's comments seek to destroy and contradict the purpose of the ACP, undermining the financial penalties by seeking a cheap way out of the obligation through force majeure. The force majeure provision should not be used to set a cost threshold lower than the ACP.

In addition, we support the comments filed by PPM Energy with regards to force majeure and alternative compliance payments.

11) Force Majeure, Alternative Compliance Payments & Cost Recovery

If the Commission rules in favor of cost recovery for alternative compliance payments, it's important that the use of alternative compliance payments are not one of the metrics used to determine force majeure, as this would create a perverse incentive for load-serving entities to create force majeure conditions at no cost to them.

12) Distribution of Alternative Compliance Payment (ACP) Funds

Alternative Compliance Payments (ACP) are penalties associated with non-compliance with obligations in specific tiers. In order to promote the cleanest forms of energy and to follow the spirit of the Act, the distribution of the ACP funds should be set up so that the ACP funds collected from the solar photovoltaic share are used specifically for solar photovoltaic development. ACP funds from the remainder of Tier I should be available to be used for any part of Tier I (solar included). ACP funds from Tier II should be available to be used for any part of Tier I or Tier II.

This proposal supports the spirit of similar comments supplied by the Solar Energy Industries Association and the Sustainable Development Fund, yet allow the flexibility of supporting cleaner technologies.

13) Net Metering – Cost & Metering Issues

Off-grid energy producers/consumers don't have to pay various utility charges for energy they aren't consuming. By the same token, net-metered customers shouldn’t be required to pay charges associated with power they don’t draw from the grid.

It’s reasonable to require two meters solely for the purpose of accurately measuring the amount of alternative energy generated for the purpose of creating alternative energy credits. However, this should not be used to justify or allow competitive transition charges or any other per-MWh charges to be applied to the full amount of power consumed. Such charges should apply only to the net amount of energy consumed. The total amount of net metering that is likely to occur is not on a scale that would be significant to the utilities. However, these charges can be quite significant to the customer-generator. It’s more important to have the proper incentives to make the use of net-metered alternative energy economically viable.

Net metered energy should be at the full retail rate, as requested in RCN’s comments.

FirstEnergy has argued for very restrictive limits on net metering. There should be no MW cap on total allowable net metering. There should also be no requirement that net metered distributed generation facilities be limited in size to the energy requirements of the host. FirstEnergy also suggests a minimum $350 “threshold application fee” for all net metering customer-generators. This is too costly for residential-sited solar photovoltaic customers to have to bear on top of the already large expenses associated with such systems. If any minimum fees are applied, they should be scaled such that residential-sited solar systems are no more than $50.

Ideally, customers who generate their own electricity should not be responsible for the first $1,000 of local distribution system upgrades needed to accommodate the utility’s purchases of their power. Implementing such a rule would reflect what has already been approved in restructuring settlements (e.g., PECO).

14) DEP Enforcement / Compliance

Section 7(b) of the Act states:

> Department responsibilities.--The department shall ensure that all qualified alternative energy sources meet all applicable environmental standards and shall verify that an alternative energy source meets the standards set forth in section 2.

DEP has proposed in their comments to abdicate their responsibility under the law by allowing self-certification of compliance and by allowing a certain level of non-compliance. DEP's comments include the following definitions:

> Compliance – **Sources seeking to qualify as eligible must annually certify** to the Department that they experienced no **major environmental compliance violations** during the reporting year. If a source reports that it has experienced a **major** compliance violation, alternative energy credits, equivalent to the number of megawatt hours generated during the period of major noncompliance, shall be disqualified from eligibility. [p1 of DEP's comments]
>
> Environmental Compliance – The customer must possess all necessary environmental permits and may not have **major** compliance violations. That **customer shall certify** on annual basis that it has all required environmental permits and is does not have a **major** compliance violation. For instances of non-compliance with this section, the customer shall be treated under the guidelines set forth by DEP in the Section 2 Technical Guidance document. The Department may verify compliance records with other state environmental agencies or the relevant federal agencies. [p7 of DEP's comments]

The Act requires that **all** applicable environmental standards be met by facilities wishing to qualify under the standard. DEP does not have the authority to change the Act to allow facilities with "non-major" violations to qualify.

The Act also requires that DEP "shall ensure" the compliance. This means that DEP must be making the determination of compliance, not simply relying on generation owners to self-certify their compliance.

It would be a breach of duty for DEP to relying on owners of out-of-state facilities to self-report their compliance. At a minimum, DEP must receive confirmation in writing from the state environmental agency in question and from the U.S. EPA that the facility has had ***no*** violations in the past year. This should not be at DEP's discretion, but should be a requirement for each facility.

DEP already has insufficient enforcement staff and does not inspect facilities frequently enough to ensure proper compliance with state laws and regulations. For DEP to be able to properly enforce their regulations on in-state facilities ***and*** verify compliance of out-of-state facilities with state and federal environmental laws, they will need additional funding for this enforcement, certification and verification.

Section 3 (e)(9) of the Act states:

> The commission may impose an administrative fee on an alternative energy credit transaction. The amount of this fee may not exceed the actual direct cost of processing the transaction by the alternative energy credits administrator. The commission is authorized to utilize up to 5% of the alternative compliance fees generated under subsection (f) for administrative expenses directly associated with this act.

These two funding mechanisms should be used to ensure that DEP has sufficient funding to do thorough enforcement, certification and verification. This can be considered part of the cost of "processing the transaction by the alternative energy credits administrator," since transactions can't be made unless it is determined that credits from a facility qualify under the Act.

15) Preemption

The Energy Association provided comments stating:

> The Act sets forth some definitive terms about the overruling of local zoning laws in particular for Tier-1 facilities. Since there are a host of laws governing wetlands, historic sites, local powers, groundwater protection, shore lands and solid waste, to name but a few, the Commission and DEP may want to anticipate these difficulties and set up a process and procedure, and most importantly a forum, to take jurisdiction over these complex and potentially competing issues.

The Energy Association is mistaken. The preemption language they're referring to only existed in a proposed draft amendment to House Bill 2250. That amendment was never formally introduced and the preemption language never ended up in any actual legislation. It is clearly **not** in the Act.

The Act gives the PUC and DEP no right to "take jurisdiction" over local zoning or to change any other laws/regulations regarding wetlands, historic sites, groundwater protection or otherwise.

16) Waste Coal

In commenting on the minimum criteria for waste coal burners, DEP stated that "the Department may develop alternative criteria by regulation." DEP should not change the waste coal definition by regulation, unless such alternative criteria ensure that no aspect of the facility's environmental impacts can be more damaging to the environment than the facilities that meet the criteria outlined in the Act. Any new alternative criteria should focus on the following areas necessary to adequately protect the environment from pollutants in waste coal:

- Landfill liners should be required at sites where waste coal ash is placed
- Air emissions controls are necessary to capture any polycyclic aromatic hydrocarbons (PAH) which are produced during combustion of waste coal
- Continuous Emissions Monitors (CEMs) for particulate matter, ammonia, and mercury ought to be required. New CEM technologies for measuring dioxins and a 9-metal CEM for measuring antimony, barium, cadmium, chromium, lead, arsenic, mercury, nickel, and zinc are in development and should be required once they are tested, verified and commercially available. More information on these technologies can be found here: http://www.epa.gov/etv/sitedocs/monitor.html

17) Fuel Cells

Fuel cells must utilize fuel that qualifies as a Tier I alternative energy source, including the use of such resources to electrolyze water. Fuels obtained from resources that are clearly not able to meet the alternative energy definition should not qualify.

18) Demand Side Management & Distributed Generation

Geothermal should be allowed to qualify in Tier II if it's used as an energy efficiency measure to reduce electric demand.

Industrial by-product technologies and distributed generation technologies should be limited to those fueled by alternative energy sources, preferably only those in Tier I.

The term "small-scale" in the distributed generation definition needs to be defined. We recommend that a size limit of 500kw be applied.

19) Solar

The Sustainable Development Fund commented that "PV systems not connected to the grid should not count." As long as these photovoltaic solar systems are displacing power that would otherwise need to be provided by the grid, they *should* be permitted to generate alternative energy credits if they fall within the geographic scope permitted under the Act. This is especially justified if no contract path is required to ensure that the electricity product itself if delivered into PJM. Since the market is for the renewable attributes, off-grid sources should be considered.

Solar thermal energy is not listed as being in a tier. This oversight should be corrected by placing it in Tier I, where it would naturally belong in such a policy. The Commission should evaluate the cost issues surrounding solar thermal energy and decide whether such technologies should be eligible for the solar share.

20) Biomass

Regarding the biomass definition, the Sustainable Development Fund commented that "the eligible feedstock does not and should not include cellulosic waste material that has been painted or chemically-treated, i.e. demolition waste."

Standards should be developed to ensure that any biomass feedstock must not be contaminated with inorganic matter of any sort. If wood pallets are to be combusted, any metal or plastic contaminants must first be removed. Materials contaminated from chemical spills or deliberate coating with paint or chemical treatments must not be allowed to be combusted. Construction (not just demolition) waste can also be contaminated with a wide range of building materials. Monitoring and enforcement mechanisms must be put in place to ensure that contaminated waste streams aren't used to feed facilities generating energy that is used to meet the Act's requirements.

DEP recommends that Tier I woody biomass resources should have to be "harvested in a manner certified as sustainable by the Forest Sustainability Council." The correct name for the certification organization is the Forest *Stewardship* Council. We support this requirement and suggest that *all* woody biomass resources (including those used to meet Tier II) should be required to be certified in this way. Pennsylvania's guidelines for this should be developed to be in harmony with the standards developed in New Jersey.

DEP would like to use self-certification for bio-energy crops. This isn't acceptable. The agency is charged with enforcing environmental standards, not with signing off on self-reported "certifications."

21) Harrisburg Incinerator

The municipal solid waste incinerator that used to exist in Harrisburg was closed on June 18th, 2003 – two and a half years after new Clean Air Act regulations went into effect, regulating dioxin emissions from large municipal waste combustors. The Harrisburg incinerator, being the largest known source of dioxin air emissions in the nation, was completely incapably of meeting the new laws. In January 2001, a Consent Order and Agreement (http://www.stoptheburn.org/coa.html) was signed by DEP and the City of Harrisburg allowing the incinerator to operate beyond the December 2000 onset of new regulations for large municipal waste combustors. This agreement allowed the incinerator to operate for the additional two and a half years, provided that they derate the facility to slip under the "large" definition into the category for which the regulations don't apply until 2005.

The facility that existed since 1972 is now closed forever. It is now illegal to operate such a facility and the facility has been dismantled. A new facility is currently under construction on the same site of the former Harrisburg incinerator. This new facility has a completely new air plan approval (allowing construction and testing of a new facility) and would still need an Operating Permit from DEP.

At the time of the passage of the Act, and on the effective date of the Act, there is no existing facility. Nothing exists on the site that is capable of generating electricity. The only functioning "facility" at the location is a tipping floor – a concrete slab that serves as a transfer station where waste can be moved from small waste trucks to larger waste trucks.

The term "existing" should be based on a facility generating (or being capable of generating) electricity on the effective date of the Act.

22) Hydropower

Low-impact hydropower should include ocean and lake-based energy if such projects meet the spirit of the definition, in terms of impact on aquatic systems. Ocean and lake-based hydropower that may not meet "low-impact" criteria should be permitted in Tier II as large-scale hydropower.

Large-scale hydropower must be defined with a size limit. It is not acceptable to include all dams that fail to meet the low-impact criteria as "large-scale." To do so would contradict the purpose of the term "large-scale." Large hydropower is generally measured as hydropower larger than 30-60 megawatts (definitions vary in different states). Minnesota and Wisconsin use 60MW limits; New York, New Jersey and Maryland use 30MW limits.

DEP argues that new hydroelectric dams should qualify as incremental hydropower for the low-impact definition. This is contrary to the accepted use of the term "incremental" and would also violate the requirement that such development "does not adversely change existing impacts to aquatic systems."

23) Load Management

The Demand Response and Advanced Metering Coaliton (DRAM) points out that alternative energy credits are in MWh (not MW) and that load management can reduce MW, but not MWh. They provide no answer for this dilemma, but point out that load management projects can cause small reductions in MWh. Only real reductions in MWh from load management projects should qualify for generation of alternative energy credits.

24) Pumped Storage

Storage isn't generation. Generation at pumped storage facilities must be measured on a yearly basis. If they manage to generate more MWh than they use, it should be eligible for creation of alternative energy credits. Otherwise, allowing energy use from short-term spurts of generation amid a long-term trend of using grid power to pump water uphill is fraudulent and would simply amount to a loophole allowing traditional coal and nuclear generation to qualify as a Tier II resource.