BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Implementation of the Alternative Energy Portfolio Standards Act of 2004	: :	Docket No. L-00060180

COMMENTS OF CITIZEN POWER TO THE PROPOSED RULEMAKING ORDER ENTERED JULY 25, 2006

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§ 75.52 Technology definitions

§ 75.52(4)(i). Low-impact hydropower

Timing of "incremental" definition should be based on operational status

Citizen Power supports the Commission's interpretation of Act 213's "low-impact hydropower" definition as one that only applies to incremental sources, but we differ in our understanding of how to define it, time-wise. § 75.52(4)(i) states that a low-impact hydropower facility must be "permitted on or after February 28, 2005, or represents capacity additions or efficiency improvements to a preexisting facility implemented on or after February 28, 2005." Permits can have little to do with operational status. It's not unusual for there to be two or more years between the date when a facility is permitted and when the facility is constructed and operational. A plain language interpretation of the time-frame meant by the term "incremental" would lend itself to a definition that revolved around operational status, not permitting. The permits needed for hydroelectric facility upgrades are granted at the state ***and*** federal levels. There are multiple permits required, yet the § 75.52(4)(i) definition makes it seem as if there's only a single permit that would serve as the determinant of whether a facility can be "incremental" or not.

Rather than try to arbitrarily pick which permits trigger the "incremental" definition, the definition should be based on the operational status. The U.S. Department of Energy's Energy Information Administration tracks electricity generating facilities using an "Initial Date of Operation" field in their data sets. This is a much more accurate and reliable measurement of the status of a facility's operation. We recommend rewording the definition to state:

> "(i) was first operational on or after February 28, 2005, or represents capacity additions or efficiency improvements to a preexisting facility implemented on or after February 28, 2005."

No new dams qualify

To further clarify the § 75.52(4)(i) definition, it would be wise to prevent confusion by making it clear that no new dams can qualify. The second "or" in the sentence implies that the first clause ("was permitted on or after February 28, 2005") could allow for facilities that are not part of additions or improvements to a "preexisting facility" as described in the second clause.

The term "incremental" is generally understood to be an expansion or improvement to an existing facility. Act 213 requires that low-impact hydropower "does not adversely change existing impacts to aquatic systems" and that it meet the certification standards of the Low Impact Hydropower

Institute (LIHI). Both the "does not adversely change…" criteria and LIHI's certification process preclude any new dams from qualifying. LIHI's Frequently Asked Questions[1] state:

> *"LIHI also excludes new dam construction – if the dam was not built as of August of 1998, it is not eligible for certification. We don't consider new dam construction because we do not want to encourage such developments – there are already plenty of dams in the United States, and we think they should be improved before more new dams are considered."*

DEP's draft Technical Guidance[2] implies that new dams would be permitted in the low-impact hydropower definition. They state:

> *"Incremental development includes new eligible facilities as well as improvements that increase electric output or capacity from existing hydroelectric sites."*

DEP's draft guidance is incorrect on this issue and conflicts with Act 213. This draft guidance has yet to be vetted through a public process. It is also outside of DEP's powers, as delegated by Act 213, to be qualifying alternative energy sources. DEP's role is to ensure and verify that alternative energy sources meet environmental standards, not to determine whether a source qualifies as alternative energy under the Act. To avoid confusion and clarify the definition to accommodate both the operational status issue and to be clear about the fact that new dams do not qualify under the Act, we recommend the following wording:

> "(i) represents capacity additions which were first operational on or after February 28, 2005 or efficiency improvements which were implemented on or after February 28, 2005 at a preexisting water impoundment facility."

§ 75.52.(a)(6)(ii). Biomass

In the final revision of the legislation which became Act 213, this phrase was specifically deleted from the definition of biomass energy (a Tier I resource): "by-products of the pulping process and wood manufacturing process including bark, wood chips, sawdust and lignin in spent pulping liquors." In the same amendment, the following item was added to Tier II: "generation of electricity utilizing by-products of the pulping process and wood manufacturing process including bark, wood chips, sawdust and lignin in spent pulping liquors."

This very obvious removal of these fuels from Tier I and placement of them in Tier II is quite clear as to legislative intent. The proposed regulations – perhaps in response to DEP's draft technical guidance – allow the following in Tier I: "bark, sawdust and clean, untreated wood chips from lumber

[1] "Low Impact Hydropower Institute – Frequently Asked Questions" http://www.lowimpacthydro.org/documents/faq.pdf
[2] "Department of Environmental Protection Alternative Energy Portfolio Standards Act, Act 213 Section 2 Technical Guidance (Draft)"
http://www.depweb.state.pa.us/energy/lib/energy/docs/section2technicalguidancefinal.pdf

mills, manufacturers or other producers that otherwise meet the definition of solid, nonhazardous, cellulosic waste material segregated from other waste materials."

If the legislature intended these fuels to be used in both Tier I and Tier II (which would make them the only technology eligible for use in both tiers), they would not have deleted them from the Tier I "biomass energy" definition. Instead, the final amendment removed them while inserting a "such as" that went on to describe other types of solid cellulosic waste – none of which are by-products of any pulping or wood manufacturing process. All of the examples in the Tier I "biomass energy" definition are agricultural in nature, with the exception of waste pallets and crates, which are cellulosic waste materials that are *not* associated with any pulping or wood manufacturing process.

As even the large pulp and paper mill owner/operator, P.H. Glatfelter, argued in their 2/15/2005 Reply Comments, it's clear from the language of Act 213 that their technology falls in Tier II and not in Tier I. To the extent that any sources of wood products are permitted to qualify as Tier I biomass resources (which we oppose), we support DEP's suggestion in their draft technical guidance that the Forest Stewardship Council must certify these resources. DEP mistakenly describes the organization as the "Forest Sustainability Council." We and P.H. Glatfelter both pointed out this mistake in our Reply Comments in February 2005. The organization's website can be found here: www.fsc.org

§ 75.52.(a)(8) Coal mine methane

We thank the Commission for recognizing and codifying in regulation that coal mine methane does not include commercially developed coal bed methane.

§ 75.52.(b)(2) Waste Coal

Circulating fluidized bed boilers

The definition of waste coal, due to poor wording in the Act, refers to the use of a "combined fluidized bed boiler." There is no such thing as a "combined fluidized bed boiler." All of the waste coal burning power plants in the nation (all but one of which are in PA and WV) use what is known as circulating fluidized bed (CFB) boilers and are "outfitted with a limestone injection system and a fabric filter particulate removal system" as the Act describes. Just as the Commission and DEP have had to clarify and correct the "Integrated Combined Coal Gasification Technology" term through definitions to mean what was really meant (Integrated Gasification Combined Cycle or "IGCC"), the Commission ought to use this opportunity to properly define CFB technology in the regulations.

Non-permitted sites

We concur with Commissioner Fitzpatrick's dissent regarding the need to define in regulation any alternative eligibility requirements for the use of waste coal from "non-permitted sites." The Act clearly states that such alternate requirements must be "established by regulation." Case-by-case determinations are not allowed by the Act.

§ 75.52.(b)(3) Conservation vs. Efficiency

Conservation and efficiency are different things. While some overlap exists, conservation generally means using less by doing without, while efficiency means using energy more efficiently. It's the difference between turning lights off or simply replacing incandescent bulbs with fluorescent bulbs. The regulations confuse the issue by using the term "conservation" when describing "efficiency" measures. The term is used in § 75.52.(b) as well as § 75.51.(a) and § 75.54.(c). We encourage the Commission to be accurate by properly describing efficiency measures as such.

§ 75.52.(b)(3)(ii) Load Management

The Commission ought to spell out in regulations how load management and demand response technologies are expected to be measurable as kWh of energy savings. If such demand shifting tactics are truly incapable of producing measurable kWh of energy savings, the Commission ought to define it in such a way to ensure that no fraudulent mirage of energy savings can be used through this vague definition.

This wouldn't be the first time that Act 213 would be codified in such a way that a technology cannot be used. Geothermal resources are such that they cannot be used to produce electricity in the PJM territory and most likely not in MISO either (with the possible exception of eastern Montana). Barring further westward expansion of PJM/MISO, there's a good chance that geothermal resources will never be used to meet the Tier I geothermal definition (ironically, they included geothermal even as the legislators rejected inclusion of ocean-based technologies because such technologies couldn't be applied within Pennsylvania). The legislature included geothermal only because it's part of the classic renewable energy definition that was handed to them. Just because the legislature included a technology doesn't mean that it makes sense or will be used. If the use of load management to produce kWh of energy savings is impossible, the Commission should ensure that it can't be used as a potential loophole.

§ 75.52.(b)(4) Distributed generation

Natural gas and diesel aren't alternative energy

Distributed generation is defined in such a vague way that it could allow almost anything. Both the fuel used and the size are undefined. The Commission views this as allowing conventional fuels such as natural gas or diesel to qualify as alternative energy sources through this definition. Although the legislature removed the phrase "using an alternative energy source at a site that does not use the facilities of an electric distribution company or a regional transmission organization to supply an end user," it should not be interpreted as meaning that the removal of the "alternative energy source" part of that phrase was intended to undermine the entire notion of "alternative energy" in the Act.

It would be a major distortion of the intent of the act to allow any fuel to be used, when the overall thrust of the Act is to promote alternative energy. The words in statutory provisions must be construed in the context of the entire section of the statute. See *Shell Oil Co. v. Iowa Dept. of Revenue,* 488 U.S. 19 (1988) ("[t]he meaning of words depends on their context.").[3]

Throughout their deliberation, the legislature never expressed a desire for distributed generation to mean anything other than alternative energy sources. If they had intended to allow conventional fossil fuels, they most likely would have included a "such as" phrase to make that clear, as they have in other definitions. For an otherwise "renewable" portfolio standard, the legislature was clear in other areas when they intended to allow non-renewable energy sources, such as coal-mine methane, waste coal and coal gasification to qualify.

As DEP suggests in their draft technical guidance, distributed energy should be limited to alternative energy sources. DEP suggests further limiting it to Tier II sources, but we see no reason for such a requirement, when it would be more proper to assume that any alternative energy source, from Tier I or Tier II ought to qualify, in the absence of any language specifically limiting distributed generation in such a way.

Small-scale is undefined

The term "small-scale" also goes undefined. This ought to be specified in regulation in order to provide clarity.

[3] Shell Oil Co. v. Iowa Dept. of Revenue, 488 U.S. 19 (1988). http://laws.findlaw.com/us/488/19.html

Solar thermal

Solar thermal energy, which was mistakenly not placed in any tier, was placed in Tier I through this regulation. We concur with that assessment, but only in the case of electricity-generating technologies.

As the Energy Association of Pennsylvania argued in their comments on Implementation Order II, solar thermal technologies that do not generate electricity (like solar hot water heating and passive solar architecture) should be in Tier II, with the energy efficiency technologies. This can be done either in the "demand side management" definition or the "distributed generation system" definition, which specifically refers to "useful thermal energy."

<u>§ 75.52.(b)(5) Coal gasification</u>

Citizen Power applauds the Commission for being clear that this definition was not intended to include "[t]he use of ICCG to create feedstocks for manufacturing or liquid fuels not used to generate electricity."

<u>§ 75.52.(b)(6) Municipal solid waste</u>

Like hydroelectric dams, there are many permits associated with municipal solid waste incinerators. The regulations should not be based on the dates of any given permit, since there are multiple and recurring permits issued and re-issued for various aspects of a municipal solid waste incinerator facility. There are also cases where permits are issued, but where the facility isn't built and operating until years after the permits are issued.

Also, the regulation is more restrictive than the Act requires, in regard to permitting. The regulation requires that the facility be "permitted by the Department," yet out-of-state municipal waste facilities are permitted by other state agencies, not the Pennsylvania Department of Environmental Protection. Since the Act doesn't define the facility in terms of permitting, this definition needs to be reworded anyway.

The plain language of Act 213 refers to "***existing*** waste to energy ***facilities***" (emphasis added). This should be interpreted to mean permitted facilities which were first operational on or before the effective date of the Act (February 28, 2005). Thus, the definition should be changed to read:

> *"Municipal solid waste – Electricity generated from permitted waste to energy facilities which were first operational on or before February 28, 2005, which the Department has determined to be in compliance with current environmental standards, including applicable requirements of the Clean Air Act (69 Stat. 322, 42 U.S.C. § 7401 et seq.)*

and associated permit restrictions and applicable requirements of the act of July 7, 1980 (P.L. 380, No. 97), known as the Solid Waste Management Act."

As there are now "municipal solid waste" incinerators that are burning wastes other than municipal solid waste (such as residual wastes, an industrial waste stream that MSW incinerators were never designed to burn), the definition ought to be further clarified so that it's understood that "municipal solid waste" means those facilities that burn only municipal solid waste and not waste streams that are more hazardous.

§ 75.53.(d) Geography

PJM and MISO resources should be available to all in the Commonwealth

Citizen Power supports the dissenting statements of Commissioners Fitzpatrick and Pizzingrilli with regard to the geographic scope question. Section 75.53.(d) does not honestly reflect the plain language in Act 213. Nowhere in the Act is there language supporting the PJM-to-PJM / MISO-to-MISO interpretation. The Act speaks nothing about where the energy may be used within the Commonwealth. It only describes where it can come from. We agree with the many commenters who support the interpretation that resources from anywhere within the Commonwealth or anywhere within PJM or MISO can be used to meet obligations under the Act *anywhere* within the Commonwealth.

Allowing this larger geography is not only technically correct, but serves some valuable purposes, including:

- Helping to ensure that force majeure won't be an issue.
- Benefiting Pennsylvania ratepayers, by allowing more competition.
- Allowing wind power from the Midwest to qualify, which is both cheaper than Mid-Atlantic wind supplies and is less harmful to the environment, since forested mountain ridgelines wouldn't have to be hit as hard by wind developers (which also tends to generate more community opposition, delaying projects and increasing costs).
- Cleaning the air in Pennsylvania by displacing more conventional resources to the west of the state, where the nation's largest concentration of existing and proposed coal power plants can be found.

NYISO should not be included

We agree with the Commission's straightforward interpretation of the Act's use of the RTO term, meaning that NYISO cannot be included in the Act, as they are not an RTO. Sticking with the language of the Act, an ISO is not an RTO and therefore would not be included. This interpretation has some benefits, as New York's RPS law is set up very differently than those in PJM (with REC trading done in the public sector), so the reciprocity argument isn't appropriate. New York also happens to be one of the top five states in the nation for the number of municipal solid waste incinerators (with 10 existing facilities). They're the only state with an RPS law, where MSW incinerators exist and where these incinerators were *not* included as an eligible renewable resource in the state law. This was intentional, as they recognized that MSW is *not* really a renewable resource and that the environmental harms posed by waste incinerators are significant enough to prevent their profiting from renewable energy policies. It would be an act of bad faith if Pennsylvania's AEPS were to allow waste incinerators in New York to profit from sales of credits to Pennsylvania when New York went through the politically difficult process of excluding them in their own law.

Pike County and the Commerce Clause

As the Office of Consumer Advocate points out in their comments on *Standards And Processes for Alternative Energy System Qualification and Alternative Energy Credit Certification*, the restrictive PJM-to-PJM / MISO-to-MISO interpretation creates a hardship upon Pike County Light and Power Company ("Pike County"). Pike County is the only EDC that cannot use resources outside of the Commonwealth because they're the only EDC that is not in a FERC-recognized RTO.

Some have raised the commerce clause question with regard to this geographic eligibility question. As generally applied, we find that argument rather weak, as the commerce clause focuses on in-state vs. out-of-state discrimination and the major question is of access to one multi-state region vs. a larger multi-state region. However, in the case of Pike County, the restrictive PJM-to-PJM / MISO-to-MISO interpretation could give rise to the first commerce clause challenge to a renewable/alternative electricity portfolio standard law. The Pike County situation provides a clear case of in-state vs. out-of-state discrimination, where they'd be the only EDC in the Commonwealth that is limited to in-state supplies. Conversely, out-of-state alternative energy suppliers could challenge the law on the basis that access to the Pike County market is being limited only to in-state suppliers.

§ 75.53.(h) Environmental compliance

Act 213 states that the Pennsylvania Department of Environmental Protection's responsibilities with regard to environmental compliance are to:

> *"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." (emphasis added)*

DEP's role and findings of non-compliance

Citizen Power agrees with Commissioner Fitzpatrick's dissent (and several other commenters) that the Act does not give DEP the authority to make decisions to qualify an alternative energy source. By requiring the program administrator to "reject applications that the Department advises to be non-compliant with environmental regulations," the regulations, in § 75.55.(b)(6), take authority from the administrator and give it to DEP.

DEP's role should be that of an advisor or even an expert witness, but not as the judge.

We expect it to be a very rare instance where DEP would declare a source to be in non-compliance – not due to the rarity of non-compliance, but due to DEP's track record of weak enforcement. In the unusual cases where DEP declares a source to be in non-compliance, we would hope and expect that the program administrator would take this seriously and reject or suspend applications as suggested in the proposed regulation. We feel that the regulations should strongly encourage the program administrator to respond with rejection or suspension when recommended by DEP. However, we would not want DEP saddled with the political or legal liability that would come with a more formal decision-making role that the Act didn't actually call for.

The program administrator should not be bound only by a DEP's finding of *compliance*, however. We ask that the regulations specify that the administrator must accept evidence from third parties regarding the compliance of a given alternative energy source. Evidence of non-compliance should be enough to allow for suspension regardless of whether the evidence was uncovered by DEP, the program administrator, or a third party whose information was delivered to and verified by the administrator. There needs to be a system where third parties can bring such information to the table, as witnesses providing evidence for the administrator to consider, without needing to go through a formal process before the Commission.

Section 75.55.(b)(8) states that the *"program administrator will provide written notice to applicants of its qualification decision within 30 days of receipt of a complete application form."* We are concerned about how this would interplay with DEP's advising on the compliance status of a facility. As described in our comments below, DEP will need to review the compliance history of facilities they regulate *as well as* out-of-state facilities. They'll likely need to respond with information on compliance of many facilities at once and may not have adequate staffing to properly and carefully review compliance.

If DEP cannot respond in a timely manner, how would this affect the 30 day deadline for making a qualification decision? If the owners of alternative energy sources are given due process to challenge evidence of non-compliance, how would *this* be done within a 30 day time frame? If a third-party provides evidence of non-compliance of a facility in another state, which DEP didn't find on its own, will the program administrator be able to reject an application or put it on hold while it investigates and confirms the evidence? Many questions have been raised (mostly by U.S. Steel) about the process on this. Regulations ought to shed some light on this complicated arena.

ALL applicable environmental standards

The law requires that ALL applicable environmental standards be met, yet the work "all" has been removed when it was written into regulation at § 75.53(f). The word "all" needs to be restored.

All applicable environmental standards – Not just major

The law requires that all applicable environmental standards be met, not just "major" ones. The regulations must follow the law and cannot restrict enforcement to "major" violations. It's also not consistent, since a violation in one state might be "major" while in another state it could be "minor" and in a third state it could be classified in such a way that can't easily be described simply as "major" or "minor."

Act 213 also doesn't limit violations to "those that cause significant harm to the environment or public health." There is no way to objectively define "significant harm to the environment or public health." Such a standard is unenforceable.

All applicable environmental standards – Not just state/federal

"All" applicable environmental standards would include any applicable *local* environmental standards. Pennsylvania's Air Pollution Control Act (at 35 P.S. 4012) allows local governments to have stricter air pollution laws that then state. Similar measures may exist in other states. There are cases where counties and municipalities have their own environmental standards that are stricter than state and/or federal law. Act 213 doesn't limit the compliance requirements to state and federal laws, as the regulations attempt to do in § 75.53.(f) – and as DEP attempts to do in several places in their draft technical guidance. How will DEP be aware of local government environmental laws? How will DEP confirm compliance with such laws? We recommend that this be resolved by requiring letters from the host municipality and county confirming that the facility is in compliance with any local environmental ordinances.

All applicable environmental standards – Not just Pennsylvania's

It's an odd situation for PA DEP to be in charge of ensuring that qualified facilities *in other states* meet the environmental standards of those states. How will DEP be aware of the laws in other states? How will DEP confirm compliance with such laws?

DEP doesn't even use its own system for determining compliance of facilities in Pennsylvania. DEP has a system called a compliance docket and it is supposed to put a company in this docket if the company is not in compliance. However, some DEP regional offices don't put any companies in the compliance docket, regardless of the fact that a facility may have a history of many, recurring violations. In other DEP regional offices, it's still a very rare occurrence – indicating that DEP's enforcement is lacking, not that there are little to no facilities with recurring environmental violations.

We request that the regulations specify some minimal level of research that DEP and the administrator must do on the compliance of a source, so that DEP and the administrator are not just taking a company's word for it that they're not in violation of other state laws. We also observe that there may not be consistent standards among states for what constitutes "in compliance." Since the Act requires the compliance be looked at in terms of all "applicable" environmental laws, it's not proper to assume that Pennsylvania's laws are the measure of compliance for facilities in other states.

Suspension

Act 213 and the proposed regulations fail to define any details of the suspension period for sources deemed not in compliance. How soon after suspension can a source reapply for qualification? Is reapplication necessary?

In addition, suspension time should be based on severity, type, duration and frequency of violations. However, a minimum threshold needs to be established – one which doesn't rely simply on the inconsistent and poorly enforced "major" threshold, or undefineable "harm" standards. For minor violations, some version of a "three strikes, you're out" rule should apply. For major violations, a single violation in the past year may be adequate. As definitions could differ among various federal, state and local regulatory schemes, a more nuanced approach will need to be developed by the administrator, hopefully with better guidance from the regulations.

Suspension time cannot be based on the duration of a violation (as some have suggested), since it's usually impossible to objectively know the duration of a violation. This is primarily due to the infrequent nature of inspections. If DEP visits a plant every 2-3 months, and notices the same violation each time, does that mean that the violation has been occurring the entire time? If the facility operator insists that it's remedied immediately after each inspection and that the violation just started that day, before the inspection, who would be able to claim otherwise? The duration of non-compliance should not be determined by the facility owner/operator, since they'd have a clear conflict of interest, with the incentive to claim that the non-compliance was as short-term as possible. In the absence of a continuous enforcement presence, duration of non-compliance cannot be used to determine the duration of suspension of qualification.

There need to be standardized minimum times for suspension of qualification. If a violation is discovered through an inspection, and the violation is claimed to be short-term and is remedied right away, there still needs to be a fixed suspension time as a penalty. Coming into compliance (i.e. starting to follow the law) after a period of non-compliance shouldn't be rewarded by immediately reinstating credits disqualified due to that non-compliance.

We agree with EPGA's comments that sources should be required to provide certain information annually to DEP, and that failure to provide such information may result in loss of qualifying status. However, we strongly advise that this self-reporting mechanism not be the limit to the examination of compliance.

What is a source?

The regulations should specify that a source is defined as a facility. P.H. Glatfelter and U.S. Steel have argued for clarification of what a "source" is, seemingly so that they could be considered in compliance even if there are violations at a part of their facility that is considered "unrelated" to the part that is generating the alternative energy. They try to argue that compliance of "unrelated" operations at the same facilities aren't relevant.

First of all, it's hard to define what is "unrelated." The Act should not be rewarding corporate criminals and environmental violators. If a facility has problems following environmental laws in one area, it probably indicates a management problem that could easily be affecting operations of the alternative energy source, even while problems at those other operations may not have been detected due to lack of aggressive enforcement. For example, compliance of landfills should be included in evaluation of landfill gas burning operations, as they're so intimately connected as operations that they're effectively the same facility (gas generation is dependent on landfill cover, piping and wells, etc.).

§ 75.54.(d) Delivery

Citizen Power supports the Commission's conclusion that "delivery" to Pennsylvania customers is not a requirement of the Act, since credits can be "purchased together with the electric commodity or separately through a tradable instrument." Delivery is required, but the Act only requires that the electricity be delivered to "the distribution system of an electric distribution company or to the transmission system operated by a regional transmission organization."

The Industrial Energy Consumers of Pennsylvania pointed out, in their comments on the *Standards And Processes for Alternative Energy System Qualification and Alternative Energy Credit Certification,* that since DSM and energy efficiency measures in other states cannot be "delivered" to Pennsylvania customers, it cannot fairly be determined that a delivery requirement exists for generation.

We agree with this interpretation and with the many points raised by the Office of Consumer Advocate in the same round of comments regarding how it's physically impossible to track and guarantee delivery anyway. This is especially true since Pennsylvania has the nation's third largest surplus of electricity generation and most electrons are likely to be flowing *out* of the state, anyway.

While the Office of Small Business Advocate has argued that the term "sold to" implies delivery, we disagree. Renewable Energy Credits (RECs) are already purchased nationally without a delivery requirement. Residents in Maine can buy RECs from California and these are sales regardless of the fact that actual product "delivery" is physically impossible.

§ 75.54.(e) Co-firing

Section 75.54(e) states:

> *"When an alternative energy system relies on more than one fuel source or technology, alternative energy credits shall be certified for that portion of the electric generation that is derived from an alternative energy fuel source or technology as identified at § 75.52."*

This section is obviously intended to apply to co-firing of combustible fuels, since it wouldn't apply to non-combustion technologies. There's a bit of a conflict between this section and Section 75.52.(a)(6)(ii) where the biomass energy definition states that it includes *"solid, nonhazardous, cellulosic waste material segregated from other waste materials."* (emphasis added). To make the two sections work together, the most consistent interpretation would seem to be that – in the case of Tier I biomass energy – co-firing is only allowed if there are no other waste materials being co-fired. Therefore, burning plant matter with coal would be acceptable (with only the MWh attributable to the plant matter qualifying), but burning something like poultry litter (which is cellulosic material – wood chips – mixed with animal waste) would not qualify since the cellulosic material (wood chips) are not segregated from other waste materials (animal waste).

It would be helpful if the regulations would make this clear, to prevent future confusion about resource eligibility.

§ 75.55.(d)(2) Double-counting

While we are glad to see the safeguard against double-counting of credits with other state RPS programs, we regret that additional forms of double-counting are not adequately prevented and – in some cases – are even being condoned.

Double-counting of emissions attributes

The Commission seems to support the notion that generators may sell, assign or trade emissions and other environmental attributes separately from the alternative energy credits themselves. The Commission even argues that it has “no authority to find that an alternative energy credit includes such values.”

We disagree. The Federal Trade Commission’s (FTC) Guides for the Use of Environmental Marketing Claims are incorporated into PUC code at § 54.6.(f). These guidelines include an “overstatement of environmental attribute” section which would be triggered if generators were to double-count by selling attributes separately from the alternative energy credits themselves.

Act 213 – in its opening sentence – seeks to support “renewable and environmentally beneficial sources.” These technologies, if stripped of their emissions attributes and other environmental attributes, would no longer be “renewable and environmentally beneficial sources.” The entire purpose of the act is to promote certain technologies due to their inherent environmental attributes. Selling these attributes separately would diminish their value as such sources.

In fact, the PUC has already moved towards this notion in its PURPA decision. Already Maine, Connecticut and New Jersey have determined that energy sold through PURPA contracts *does* include the energy’s renewable energy attributes. The ALJ’s recommended decision on the matter as it’s been brought forth in Pennsylvania by Metropolitan Edison was issued on July 13, 2006, concluding that EDCs owned the alternative energy credits associated with their PURPA contracts.

Just as electricity sales under PURPA inherently include REC/AEC attributes, the AECs themselves inherently include their emissions attributes (that’s where their value as environmentally-preferable technologies comes from). An AEC that is sold for $X should not receive a full $X if its emissions attributes are sold separately.

While the FTC guides mentioned above address environmental marketing claims in a general sense, the National Association of Attorneys General dealt with the issue more directly in their environmental marketing guidelines for electricity products, published in 1999.[4] These guidelines oppose double-counting and specifically argue that the environmental attributes of electricity should not be double-sold. Text from their guidelines are as follows:

Page 5 of the Guidelines (page 6 of the PDF)
b. Substantiation (last paragraph before Comment)

"In addition, no more than one certificate should be issued for any one unit of power."

Page 7 of the Guidelines (page 8 of the PDF)
b. Substantiation
Comment. (last paragraph before examples)

> "The Attorneys General do not take a position on which method of substantiation – auditable contract paths, tradable certificates, or some other method – a state should adopt. However, recognizing that some states are already moving in the direction of permitting either auditable contract paths or tagging as means of substantiation, the Attorneys General have adopted a Guideline that seeks to ensure that whichever system is used, (1) reasonable substantiation exists prior to the time an environmental marketing claim is made, (2) substantiation data can be averaged over a fair and reasonably recent period of time, and (3) ***claims relating to electricity (or its attributes) are not "double-sold."*** If a tagging system is adopted, the Attorneys General also recommend that disclosure be made so that consumers understand the meaning of tagging-based claims." (Emphasis added.)

This issue has been analyzed well by the organization that sponsors the nation's leading green energy certification body, Green-e. They have chosen not to allow the sales of tradable renewable certificates in their program if any of the environmental attributes have been separated and sold into other programs like carbon markets. The March 2004 report, titled "*Tradable Renewable Certificates and Emissions Values: The CRS Perspective on Best Practices in Marketing*" can be found here: http://www.resource-solutions.org/lib/librarypdfs/TRCs_and_Emissions.pdf

Finally, the GATS system tracks emissions data among the other attributes of the credits they track. By tracking emissions, it will give the impression that these emissions attributes are an attribute of the credit, even though these attributes may be being sold into other attributes markets, which ought to devalue the credit (but without disclosure, no one will be the wiser).

[4] National Association of Attorneys General green energy marketing guidelines (1999): http://www.eere.energy.gov/greenpower/markets/pdfs/naag_0100.pdf

Double-counting with ACP-funded projects

Alternative Compliance Payments are in lieu of actual compliance and either serve as a penalty for non-compliance or – in force majeure situations – would be recovered via increased costs to ratepayers. It would therefore be inappropriate for any projects developed with ACP funds to develop credits of their own, as this would be a form of double-recovery. We urge the Commission to specify in regulations that this form of double-counting would not be permitted.

Double-counting with voluntary purchasing markets

It has been claimed that GATS will protect against double-counting of AECs with voluntary green pricing programs. This, however, assumes that all credits sold on the voluntary market are reported to and tracked by GATS. Some have pointed out that GATS would not be tracking MISO resources and that MISO has no comparable tracking system. Since MISO resources will be eligible at least in the Penn Power territory, we assume that GATS will have to be tracking MISO resources to some degree. However, it's likely that most voluntary purchases of renewable energy from facilities in MISO would not be tracked by GATS. Credits from such energy could then be used to meet the AEPS and would be tracked in GATS only once. Such double-counting would escape detection.

We recommend resolving this by requiring in regulation that part of the application process involve certifying that credits will not be sold in any voluntary marketing programs or used to meet any other state RPS program requirements.

Double-counting with other state RPS programs

In the absence of the certification process suggested above, double-counting with other states could even be a problem. If a generator in MISO used their credits to meet another state RPS requirement, how would GATS or any other process catch it? Even within PJM, what would happen if credits are first used to meet the PA AEPS requirements and are later used to meet the requirements of another state RPS (provided that the other state doesn't have such double-counting protections)? Would the eligibility be retracted retroactively? If the second use isn't tracked in GATS, how would it be detected?

§ 75.56-58. Force majeure / Alternative compliance payments

Citizen Power thanks the Commission for deciding that the force majeure determinations should be made through an objective process by the Commission, rather than being a determination that a supplier initially makes. We also thank the Commission for choosing to make separate force majeure determinations for the Tier I obligation, solar photovoltaic obligation, and Tier II obligation.

We believe that the force majeure threshold ought to be higher than the ACP so that it doesn't risks undercutting the ACP. However, to avoid picking a threshold out of thin air, it would serve the same purpose to do the averaging for force majeure determinations over the 1-year reporting periods, not the 6-month periods proposed in regulation. There is nothing in the law about 6 month evaluations, making the choice of a 6 months time frame just as arbitrary as picking a threshold price. Since the reporting cycles are yearly, the averaging period for determining force majeure should follow those yearly reporting periods, which would be a more supportable interpretation of the Act. Slightly raising the bar in this manner would help ensure that renewables are still developed through ACP funds if prices hover around ACP range for 6 - 11 months.

Rather than lowering the requirements under a force majeure determination, the alternative energy obligations should be banked to future years, as PPM suggested in their initial comments (1/13/2005, p.6) so that the full intent of the law is still met.

§ 75.57.(d) Grammar mistake

Section 75.57.(d) states:

> *"If the Commission determines that force majeure exists for a reporting period for, EDCs and EGSs shall have the option of making alternative compliance payments in lieu of compliance with § 75.51 for that reporting period."*

Assuming this is a typo, the second "for" should be deleted.

§ 75.61. Banking

If certain market players bank large volumes of credits, could this potentially lead to an artificial force majeure situation for other market players if they create a shortage of available credits? We are unclear on whether this sort of gaming is prevented through these regulations and we ask the Commission to examine the matter.

Also, can electricity generated in future years be banked? Several "green energy" marketers have already been marketing and selling power that will be generated in the future, raising concerns about potential consumer fraud if those resources don't come to fruition. We'd like to be sure that electricity that has not yet been generated cannot be turned into credits and used for compliance with the AEPS or be banked in any way.

§ 75.62.(d) Disclosure

The proposed regulations state that:

"[t]he prices paid for individual credits will be treated as confidential information by the Commission. Aggregate pricing data on alternative energy credits will be made available to the public by the Commission or the program administrator on a regular basis."

However, Act 213 states:

*"The commission or its designee shall develop a registry of pertinent information <u>regarding **all** available alternative energy credits</u>, credit transactions among electric distribution companies and electric generation suppliers, the number of alternative energy credits sold or transferred and the <u>price paid</u> for the sale or transfer of the credits. <u>The registry shall provide **current** information to</u> electric distribution companies, electric generation suppliers and <u>the general public</u> on the status of alternative energy credits created, sold or transferred within this Commonwealth." (emphasis added)*

We don't believe that the Commission's "regular basis" term is consistent with the "current information" required under law. Just as Maryland's RPS law requires, we hold that "current" means that credit trading information should be made publicly available on a daily basis through an Internet web site. All information that is made available to electric distribution companies and electric generation suppliers should also be made available to the general public through a public website.

In addition, it is insufficient to make only aggregated cost data available, as that information would likely not be specific enough for the general public to analyze it by all categories possible (company, specific fuel type, region of origin, tier, etc.). Also, providing averaged data doesn't disclose price spikes that may only be evident by looking at a specific technology, within a specific tier, within a certain geography and time frame. Without the ability to analyze the data in these various ways, the public is disadvantaged, as pricing information cannot be studied.

The information made available in the registry should include:

- the current status of credits as they're generated, specifying the facility that generated the credit, the fuel type, location (city, county and state) and owner and operator of the facility.
- the annual obligation of each electric distribution company and electric generation supplier and their specific means of compliance, including how many credits met through alternative compliance payments.
- identification of each credit with either Tier I or Tier II.
- pricing information and information on the buyers and sellers in each transaction

The information should be made available in an online database that can be searched and sorted by tier, facility, technology (including breakdowns by types of biomass or other fuels), location and owner. It should also be available to be downloaded in its entirety in a commonly-available database format, like Microsoft Access. Reports should also be available for download in non-proprietary "flat" formats such as comma-delimited text.

We are thankful to see market players like ARIPPA and PPL commenting that pricing information ought to be publicly available in full credit-level detail and on a daily basis. We don't believe that such pricing information warrants confidentiality or that Act 213 permits such confidentiality. The fact that EPA's SO_2 trading market has prices publicly available is a testament to the non-threatening nature of such disclosure.

We also find ARIPPA arguments compelling in that the public is best served by a more vibrant and open market where self-dealing between EDCs and their affiliates and other such abuse would be prevented via transparency of the system.

The GATS Tentative Order states that:

> *"GATS makes available three types of reports: account holders, state agencies, and general public. <u>Account holders may access ten</u> different reports documenting their account status and transaction history. <u>State agencies may access seventeen</u> different reports documenting account holder information. The <u>public may access eight</u> different reports documenting general GATS information and statistics." (emphasis added)*

Nothing in the language of Act 213 justifies the differential treatment, where the general public is short-changed, with access to the fewest reports of any of the participants. Will the reports accessible to state agencies be unavailable through Open Records laws? If so, on what legal basis?

We ask the Commission to spell out more open and detailed disclosure requirements in the regulations.

Green Marketing

The Commission invited comments on "how EDCs and EGSs should distinguish between their traditional and alternative energy generation offerings, and the level of specificity required when marketing this information." If marketers mention the part of their mix which is required under AEPS, they should specify which part that is, and which part goes above and beyond the AEPS requirements. If marketing any "green" aspects of their "beyond AEPS" products, they should be required to also mention the same AEPS-required part of their mix in their conventional product, so that they can't create the illusion that there is a greater difference between their products than is justified.

AEPS-required resources should specifically point out that this is what all suppliers are required to have by law. This should be printed in noticeable font sizes and nearby any other "green" marketing claims. If emissions or other environmental attributes have been sold elsewhere, no "green" claims should be permitted for that portion of their product unless they can meet the requirements of the National Association of Attorneys General green electricity marketing guidelines.

GATS fee waiver

As was pointed out by IECPA, the GATS annual fee is waived for aggregate generators under 10MW and should also be waived for DSM/EE entities under 10MW. We agree and ask that this be codified in regulation.

In summary, here are Citizen Power's recommendations:

1. § 75.52(4)(i). Low-impact hydropower definition should be based on the operational status.
2. § 75.52(4)(i). Clarify that new dams do not qualify as low-impact hydropower.
3. § 75.52.(a)(6)(ii). Bark, sawdust and clean, untreated wood chips from lumber mills, manufacturers or other producers belong in Tier II, not Tier I.
4. § 75.52.(a)(6)(ii). If wood products were to be placed in Tier I, then the Forest Stewardship Council must certify these wood products.
5. § 75.52.(b)(2). Define "combined fluidized bed boiler" as "circulating fluidized bed boiler."
6. § 75.52.(b)(2). Replace case-by-case determinations on non-permitted waste coal site eligibility with a regulatory definition.
7. § 75.52.(b), § 75.51.(a) and § 75.54.(c). Accurately describe efficiency measures.
8. § 75.52.(b)(3)(ii). Spell out in regulations how load management and demand response technologies are expected to be measurable as kWh of energy savings.
9. § 75.52.(b)(3)(ii). Ensure that load management can't be used as a potential loophole for fraud.
10. § 75.52.(b)(4). Distributed generation can only include alternative energy fuels as defined in the Act.
11. § 75.52.(b)(4). Define "small-scale" distributed generation.
12. § 75.52.(b)(4). Place non-electricity-generating solar thermal energy in Tier II.
13. § 75.52.(b)(6). MSW regulations should not be based on the dates of any given permit, but on operational status.
14. § 75.52.(b)(6). Reword MSW definition to correct error about permitting agency.

15. § 75.52.(b)(6). Clarify MSW definition so that other waste streams are not included.

16. § 75.53.(d). Use the less restrictive geographic definition.

17. § 75.53.(d). NYISO should not be included.

18. § 75.53.(f). Allow third-party to submit compliance-related evidence to the administrator.

19. § 75.53.(f). Clarify the process for compliance determination.

20. § 75.53.(f) & (h). All (not just major) applicable environmental standards must be met, including local and out-of-state.

21. § 75.53.(f). Guarantee a minimal level of research that DEP and the administrator must do on the compliance of a source.

22. § 75.53.(h). Develop suspension procedures.

23. § 75.53.(h). Specify that a source is defined as a facility.

24. § 75.54.(e). Clarify allowable co-firing language.

25. § 75.55.(d)(2). Disallow double-counting of emissions attributes.

26. § 75.55.(d)(2). Disallow double-counting with ACP-funded projects.

27. § 75.55.(d)(2). Adequately prevent double-counting with voluntary purchasing markets or other state RPS programs.

28. § 75.56-58. Determine force majeure based on yearly reporting cycles.

29. § 75.56-58. Under force majeure conditions, bank obligations to future years.

30. § 75.57.(d). Fix grammar mistake.

31. § 75.61. Examine whether banking of credits could lead to artificial force majeure conditions.

32. § 75.61. Prevent banking or sales of future energy generation.

33. § 75.62.(d). Spell out more open and detailed GATS disclosure requirements.

34. Ensure that green marketing claims are accurate and genuine.

35. Ensure that GATS fee for small DSM/EE marketers is waived.