

PROPOSED RULEMAKING

PENNSYLVANIA PUBLIC UTILITY COMMISSION

[52 PA. CODE CH. 75]

[L-2014-2404361]

Implementation of the Alternative Energy Portfolio Standards Act of 2004

The Pennsylvania Public Utility Commission (Commission), on February 20, 2014, adopted a proposed rulemaking order amending existing regulations to comply with the act of July 17, 2007 (P. L. 114, No. 35) (Act 35 of 2007) and the act of October 15, 2008 (P. L. 1592, No. 129) (Act 129 of 2008), and to clarify issues of law, administrative procedure and policy.

Executive Summary

The Alternative Energy Portfolio Standards (AEPS) Act of 2004, effective February 28, 2005, establishes alternative energy portfolio standards for electric distribution companies (EDCs) and electric generation suppliers (EGSs) operating in Pennsylvania. 73 P. S. §§ 1648.1—1648.8 and 66 Pa.C.S. § 2814. EDCs and EGSs must supply 18 percent of their retail electric sales using alternative energy resources by 2021, meeting their AEPS requirements through the purchase of alternative energy credits (AECs) in amounts corresponding to the percentage of retail electric sales required from alternative energy sources. 52 Pa. Code § 75.61.

The AEPS Act requires that the Pennsylvania Public Utility Commission (PUC) and the state Department of Environmental Protection (DEP) work cooperatively to monitor the performance of all aspects of the AEPS Act and prepare an annual report for the state Senate Environmental Resources and Energy Committee and the state House Environmental Resources and Energy Committee.

The AEPS Act requires the PUC to develop technical and net metering interconnection standards for customer-generator facilities. 73 P. S. § 1648.5. Act 35 of 2007 amended certain net metering and interconnection definitions and provisions. Act 129 of 2008 amended the AEPS Act by modifying the scope of eligible Tier I alternative energy sources and Tier I compliance obligations. 66 Pa.C.S. § 2814.

The Commission has previously implemented rulemakings to implement the AEPS Act and its subsequent legislative amendments. Now, the Commission proposes to revise its regulations pertaining to the net metering, interconnection, and portfolio standards provisions of the AEPS Act pursuant to Act 35 of 2007 and Act 129 of 2008, as well as to clarify certain issues of law, administrative procedure, and policy.

Public Meeting held
February 20, 2014

Commissioners Present: Robert F. Powelson, Chairperson; John F. Coleman, Jr., Vice Chairperson; James H. Cawley; Pamela A. Witmer; Gladys M. Brown

Implementation of the Alternative Energy Portfolio Standards Act of 2004; Doc. No. L-2014-2404361

Proposed Rulemaking Order

The Commission is charged with carrying out the provisions of the Alternative Energy Portfolio Standards

Act of 2004 (the “AEPS Act”), 73 P. S. § 1648.1, et seq. This obligation includes the adoption of any regulations necessary for its implementation and enforcement. The Commission has promulgated regulations pertaining to the net metering, interconnection and portfolio standard provisions of the AEPS Act.

Based on our experience to date in implementing the current regulations, the Commission finds that it is necessary to update and revise these regulations to comply with Act 129 of 2008, and Act 35 of 2007, and to clarify certain issues of law, administrative procedure and policy. These proposed revisions are being issued for public comment. After receipt and review of public comment, the Commission will issue a final rule for approval consistent with regulatory review process.

Background

The AEPS Act, which became effective February 28, 2005, establishes an alternative energy portfolio standard for Pennsylvania. The Pennsylvania General Assembly charged the Commission with implementing and enforcing this mandate in cooperation with the Pennsylvania Department of Environmental Protection (DEP). 73 P. S. §§ 1648.7(a) and (b). The Commission determined that the Act is in pari materia with the Public Utility Code, and that it would develop the necessary regulations to be codified at Title 52 of the Pennsylvania Code. 1 Pa.C.S. § 1932.

The AEPS Act has been amended on two occasions. Act 35 of 2007, which took effect July 19, 2007, amended certain definitions and provisions for net metering and interconnection. Act 129 of 2008, which became effective on November 14, 2008, amended the AEPS Act by modifying the scope of eligible Tier I alternative energy sources and the Tier I compliance obligation. See 66 Pa.C.S. § 2814.

The Commission has previously issued the following rulemakings to implement the AEPS Act and its subsequent amendments:

- The Commission issued final, uniform net metering regulations for customer-generators. Final Rulemaking Re Net Metering for Customer-generators pursuant to Section 5 of the Alternative Energy Portfolio Standards Act, 73 P. S. § 1648.5, L-00050174 (Final Rulemaking Order entered June 23, 2006). These regulations were approved by the Independent Regulatory Review Commission (IRRC) and became effective on December 16, 2006.
- The Commission issued final, uniform interconnection regulations for customer-generators. Final Rulemaking Re Interconnection Standards for Customer-generators pursuant to Section 5 of the Alternative Energy Portfolio Standards Act, 73 P. S. § 1648.5, L-00050175 (Final Rulemaking Order entered August 22, 2006, as modified on Reconsideration September 19, 2006). These regulations were approved by the IRRC and became effective on December 16, 2006.
- The Commission revised the net metering regulations and certain definitions to be consistent with the Act 35 of 2007 amendments through a final omitted rulemaking. Implementation of Act 35 of 2007; Net Metering and Interconnection, Docket No. L-00050174 (Final Omitted Rulemaking Order entered July 2, 2008). These revisions were approved by IRRC and became effective November 29, 2008.

- The Commission issued final regulations governing the portfolio standard obligation. Implementation of the Alternative Energy Portfolio Standards Act of 2004, L-00060180 (Final Rulemaking Order entered September 29, 2008). These regulations were approved by IRRC and became legally effective December 20, 2008.

The above-referenced regulations are codified at Chapter 75 of the Public Utility Code, 52 Pa. Code §§ 75.1, et seq.

The Commission issued an Order to implement the AEPS related provisions of Act 129 in 2009. Implementation of Act 129 of 2008 Phase 4—Relating to the Alternative Energy Portfolio Standards Act, Docket M-2009-2093383 (Order entered May 28, 2009). This rulemaking will also codify the processes and standards identified in that Order.

Summary of Changes

For reasons of efficiency, the Commission will propose revisions to the portfolio standard, interconnection and net metering rules through a single rulemaking proceeding. The proposed changes to the existing regulations include, but are not limited to, the following:

- The addition of definitions for aggregator, default service provider, grid emergencies, microgrids and moving water impoundments.
- Revisions to the interconnection rules to reflect the increase in limits on customer-generator capacity contained in the Act 35 of 2007 amendments.
- Revisions to net metering rules and inclusion of a process for obtaining Commission approval to net meter alternative energy systems with a nameplate capacity of 500 kilowatts or greater.
- Clarification of the virtual meter aggregation language.
- Clarification of net metering compensation for customer-generators receiving generation service from electric distribution companies (EDCs), default service providers (DSPs) and electric generation suppliers (EGSs).
- Revisions to the definitions for low-impact hydropower and biomass to conform with the Act 129 of 2008 amendment.
- Addition of provisions for adjusting Tier I compliance obligations on a quarterly basis to comply with the Act 129 of 2008 amendments.
- Addition of provisions for reporting requirements for new low-impact hydropower and biomass facilities in Pennsylvania to comply with the Act 129 of 2008 amendments.
- Clarification of Commission procedures and standards regarding generator certification and the use of estimated readings for solar photovoltaic facilities.
- Clarification of the authority given to the Program Administrator to suspend or revoke the qualification of an alternative energy system and to withhold or retire past, current or future alternative energy credits for violations.
- Clarification of the process for verification of compliance with the AEPS Act.
- Standards for the qualification of large distributed generation systems as customer-generators.

Discussion

The following sections identify proposed revisions to the rules and the Commission's rationale.

A. General Provisions: § 75.1 Definitions

We have revised and clarified several definitions to conform with the amendments to and the intent of the AEPS Act. Furthermore, we have added definitions to provide clarity and guidance in accordance with the intent of the AEPS Act as amended.

1. Aggregator

We have added a definition for aggregator as this term is used later in these regulations. In the context of the AEPS Act, an aggregator is a person or entity that maintains a contract with alternative energy system owners to combine the alternative energy credits from multiple alternative system owners to facilitate the sale of the credits. In implementing the AEPS Act, we have found that, due to the small size of many residential solar photovoltaic systems and the fact that one alternative energy credit equals one megawatt, most of these small alternative energy system owners have difficulty selling the few credits they produce due to the administrative burdens and costs associated with finding a buyer. Due to these barriers, persons and entities have stepped in to assist these small system owners by combining or aggregating the credits produced by many of these small systems and selling those bundled credits. These aggregators are often the point of contact for EDCs and the program administrator when the systems are certified and the output is verified. As such, we have included aggregators in these regulations where the regulations address the interaction between the program administrator and system owners.

2. Alternative Energy Sources

The definition of alternative energy sources is revised to reflect the amendments to the definition for low-impact hydropower and biomass facilities from Act 129. The definition of Tier II alternative energy source will also be revised consistent with the change to the definition for biomass facilities in Act 129.

3. Distributed Generation System

We have also proposed more precise definitions for elements of the definition for distributed generation systems, which is defined as "the small-scale power generation of electricity and useful thermal energy." See Annex A at 3. The current regulation simply repeats the definition in the AEPS Act. This definition is too ambiguous to be useful, and does not provide satisfactory regulatory guidance to potential applicants regarding whether they can qualify a system as an alternative energy source. To provide clarity we have added a capacity limit to provide guidance on what small-scale facilities qualify. In addition, we have added a definition for useful thermal energy that is technology and fuel neutral but does not include common merchant generation facilities, such as combined-cycle electric generation facilities. We believe the proposed definition captures the intent of the General Assembly to use the waste heat from the generation of electricity to offset the use of another fuel source to generate heat for a purpose other than the generation of electricity. The proposed definition will permit a combined heat and power facility with a nameplate capacity of five megawatts or less to qualify as a Tier II alternative energy source.

Defining small-scale is more difficult. Unlike useful thermal energy, the phrase small-scale is not a commonly

recognized or defined term in the context of the regulation of electric generation. However, given that this is a form of distributed generation, we find it reasonable to apply the capacity limits for customer-generators, who are eligible to net meter and interconnect distributed generation resources, to the definition of distributed generation systems. The AEPS Act places a cap of five megawatts on customer-generators. Accordingly, we will limit this Tier II alternative energy source to five megawatts of capacity as well. We note, however, that such distributed generation does not have to qualify as a customer-generator to qualify as a Tier II alternative energy source.

4. *Customer-Generator and Utility*

We also revised the definition of customer-generator and added a definition for utility to make it clear that the definition applies to retail electric customers and not electric utilities, such as EDCs and merchant generators that are in the business of providing electric services. In addition, the changes make it clear that non-electric utilities, such as water and wastewater utilities are not included in the definition's prohibition against utilities qualifying as a customer-generator.

The AEPS Act defines customer-generator as “[a] nonutility owner or operator of a net metered distributed generation system with a nameplate capacity of not greater than 50 kilowatts if installed at a residential service or not larger than 3,000 kilowatts at other customer service locations. . . .” 73 P.S. § 1648.2. In analyzing this definition, we note that the legislature used the word customer in this term. Customer is defined as “one that purchases a commodity or service.”¹ Furthermore, it must be noted that the Public Utility Code defines customer as a retail electric customer in the context of the electric utility industry. See 66 Pa.C.S. § 2803. The Public Utility Code further defines a retail electric customer as a direct purchaser of electric power. *Id.* In the context of the AEPS Act, the commodity or service being provided is electricity or electric service. Accordingly, the term customer-generator by itself connotes an entity which is primarily an end user of electricity or electric service from EDCs, EGSs and merchant generators that provide these services by a person or entity that owns or operates the distributed generation system. The person or entity must purchase electricity or electric service to be considered a customer under the AEPS Act.

Furthermore, this definition specifically identifies a customer-generator as a “nonutility owner or operator” of the distributed generation system. While the AEPS Act does not define what a utility or nonutility is, common usage of the term utility, in the context of the purchase of electricity or electric service, is defined as “a service (as light, power, or water) provided by a public utility.”² Thus, a nonutility would be one who does not provide a service, such as electric service in the context of the AEPS Act. A customer-generator is one who is not in the business of providing electric power to the grid or other electric users. As such, we have defined a utility in this context as a person or entity whose primary business is electric generation, transmission, or distribution services, at wholesale or retail, to other persons or entities.

5. *Grid Emergencies and Microgrid*

The AEPS Act permits facilities with a nameplate capacity of between three megawatts and up to five megawatts to qualify as customer-generator facilities pro-

vided that they make their systems available to operate in parallel with the electric utility during grid emergencies as defined by the regional transmission organization (RTO) or where a microgrid is in place for the primary or secondary purpose of maintaining critical infrastructure. We have added definitions for grid emergencies and microgrid to provide guidance on when facilities with a nameplate capacity of between three megawatts and up to five megawatts meet the conditions to qualify as a customer-generator.

The definition for grid emergencies comes from PJM Manual 13 Emergency Operations.³ As PJM is currently the only RTO serving Pennsylvania, we believe this definition is appropriate.

The definition for microgrid references and incorporates the description of a microgrid provided by the Institute of Electrical and Electronic Engineers (IEEE) standard 1547.4. This standard can be found in the IEEE Guide for Design, Operation, and Integration of Distributed Resource Island Systems with Electric Power Systems.

6. *Moving Water Impoundment*

The definitions for large-scale hydropower and low-impact hydropower in the AEPS Act both contain the phrase “the hydroelectric potential of moving water impoundments.” The AEPS Act, however, does not define what moving water impoundments are. We have added a definition for moving water impoundments to provide guidance and clarity. This definition is intended to make it clear that in addition to hydroelectric facilities that utilize dams to impound water, electric turbines placed in rivers or streams without a dam also qualify as hydropower within the AEPS Act.

7. *Default Service Provider*

We have addressed the role of default service providers (DSPs) in net metering provisions of the regulations. While we acknowledge that EDCs currently fill the role of DSP, the Public Utility Code does provide for an alternative supplier to supply default service upon Commission approval. Therefore, we propose a definition for DSP that is consistent with the definition found in the Pennsylvania Public Utility Code at 66 Pa.C.S. § 2803.

B. *Net Metering: § 75.13. General Provisions*

This section features several revisions related to who can qualify for net metering and the compensation they receive. In addition, we have addressed the role of DSPs in net metering and the compensation they provide. While we acknowledge that EDCs currently fill the role of DSP, the Public Utility Code does provide for an alternative supplier to supply default service upon Commission approval. The addition of DSPs to this section simply acknowledges this possibility and provides guidance and clarity regarding a DSP's role in providing net metering and compensation under net metering.

1. *Section 75.13(a)*

Currently, Section 75.13(a) requires EDCs to offer net metering to customer-generators and provides that EGSs may offer net metering to customer-generators under the terms and conditions set forth in agreements between the EGS and the customer-generator taking service from the EGS. The current regulation is silent as to which customer-generators can net meter, other than that they must be using Tier I or Tier II alternative energy sources.

³ See PJM Manual 13, PJM Manual for Emergency Operations at 3, which is available at the following link: <http://www.pjm.com/-/media/documents/manuals/m13.ashx>.

¹ See *Webster's Ninth New Collegiate Dictionary* 318 (1983).

² See *Webster's Ninth New Collegiate Dictionary* 1300 (1983).

We have added a provision for DSPs and have moved the EGS net metering role to subsection 75.13(b) and re-lettered the remaining subsections. In our proposed new section (a), we require EDCs and DSPs to offer net metering to customer-generators that generate electricity on the customer-generator's side of the meter using Tier I or Tier II alternative energy sources, on a first come, first served basis, provided they meet certain conditions.

The first condition requires the customer-generator to have load, independent of the alternative energy system, behind the meter and point of interconnection of the alternative energy system. To be independent, the electric load must have a purpose other than to support the operation, maintenance or administration of the alternative energy system. This provision makes explicit what was previously implied in the AEPS Act and the regulations.

This requirement is implied in the AEPS Act definition of net metering where it states that net metering is the means of measuring the difference between the electricity supplied by an electric utility and the electricity generated by the customer-generator when any portion of the electricity generated by the alternative energy generating system is used to offset part or all of the customer-generator's requirements for electricity. If there is no independent load behind the meter and point of interconnection for the alternative energy system, by definition, the customer-generator has no requirement for electricity to offset. In addition, this requirement is implied in the current regulations, where it states that EDCs shall offer net metering to customer-generators that generate electricity on the customer-generator's side of the meter. Again, there would be no need for a customer's electric meter if there was no independent demand for electricity. Furthermore, we note that both alternative and traditional electric generation facilities require electric service to start, operate and maintain those facilities. Thus, to preclude utilities, such as merchant generators, from qualifying for net metering, we require load independent of the generation facility. To do otherwise would be contrary to the definition of a customer-generator that only includes nonutility owners and operators of alternative energy systems.

The second condition requires that the owner or operator of the alternative energy system may not be a utility. As noted previously, the AEPS Act defines a customer-generator as a nonutility owner or operator of a net metered distributed generation system. Again, this condition makes explicit in the rule what is required by the AEPS Act.

The third condition requires that the alternative energy system be sized to generate no more than 110 percent of the customer-generator's annual electric consumption at the interconnection meter and all qualifying virtual meter aggregation locations. The AEPS Act sets maximum nameplate capacity limits for customer-generators by customer class, with 50 kilowatts for residential service and three megawatts at other service locations and up to five megawatts under certain circumstances. To this point, the Commission has not set more restrictive size limitations on customer-generators, except in a policy statement permitting net metering of third-party owned and operated systems. See *Net Metering—Use of Third Party Operators*, Final Order at Docket No. M-2011-2249441 (entered March 29, 2012). In that order, the Commission set the 110 percent size limit as a reasonable way to limit the possibility of merchant generators posing as customer-generators. The Commission further noted

that the majority of comments supported the limit as a reasonable and balanced approach to support the intent of the AEPS Act and limiting the potential for merchant generators to use net metering to circumvent the wholesale electric market and gain excessive retail rate subsidies at retail customer expense. See *Net Metering—Use of Third Party Operators*, Final Order at 8.

While we declined to extend the application of the 100 percent limitation of systems owned or operated by a customer-generator in the policy statement,⁴ we now believe that this same reasonable and balanced approach should apply to all new customer-generators as it more appropriately supports the intent of the AEPS Act. Again, we point out that the AEPS Act defines net metering as a means for a customer-generator to offset part or all of the customer-generator's requirements for electricity. In addition, it ensures that the customer-generator is not acting like a utility or merchant generator, receiving excessive retail rate subsidies from other retail rate customers.

As we adopted in the policy statement, the 110 percent limit is a design limit to be based on historical or estimated annual system output and customer usage, both of which are affected by weather that is beyond the control of the customer.⁵ It is not to be used as a hard kilowatt-hour cap on the customer-generator's system output. We believe that this approach appropriately captures the intent of the AEPS Act regarding net metering and is consistent with how net metering is treated in other states.⁶

The fourth, fifth and sixth conditions simply require that the customer-generator's alternative energy system cannot exceed the nameplate capacity limits, by rate class, set forth in the AEPS Act. As noted above, these are maximum limits on the size of net metered systems. We recognize that even with the 110 percent of annual electric consumption size limitation, some systems may be able to exceed the statutory maximum size limits due to large annual electric demand. Accordingly, we have included these conditions to make it clear that customer-generator systems cannot exceed the statutory nameplate capacity limits.

Finally, in the seventh condition, we have imposed a requirement that all alternative energy systems with a nameplate capacity of 500 kilowatts or greater obtain Commission approval for net metering in accordance with a process we have added to the regulations and discuss below. We believe that this approval process will ensure uniform application of the net metering rules throughout the Commonwealth. We believe that the limiting of Commission review to systems equal to or greater than 500 kilowatts appropriately balances the need for consistent application with the additional administrative efforts and costs such a review imposes. We believe that customer-generators who have the capital to invest in these large and more costly systems will have the resources to comply with this review process. In addition, we believe that the total number of such systems applying for net metering in a year will remain relatively small such that it will not burden the EDCs or the Commission.

⁴ See *Net Metering—Use of Third Party Operators*, Final Order at 9.

⁵ *Id.* at 10.

⁶ See, 26 Del. Admin. Code 3001-8.6.2: "The customer-Generator Facility is designed to produce no more than 110% of the Customer's aggregate electrical consumption. . . ." See also, N.J.A.C. 14:8-4.3(a): EDCs "shall offer net metering . . . provided that the generating capacity of the customer-generator's facility does not exceed the amount of electricity supplied . . . to the customer over an historical 12-month period. . . ." And, N.J.A.C. 14:8-7.3(a)(2): "The generating capacity of the eligible customer's system does not exceed the combined metered annual energy usage of the customer's qualified facilities."

2. Section 75.13(b)

As noted above, we moved the reference to EGSs offering net metering to subsections (b) and re-lettered the remaining subsections. In addition, we added the phrase “or as directed by the Commission” to this subsection. This phrase is intended to make it clear that the Commission has the authority to direct EGSs to offer net metering in certain circumstances. In particular, the Commission would have the authority to direct EGSs to offer net metering if the EGSs are acting in the role of default service provider. This provides consistent and clear guidance along with the addition of references to DSPs added to these rules.

3. Section 75.13(d)

Formerly subsection (c), subsection (d) is revised to include DSP, add a hyphen between the words “customer” and “generator” and to provide clarity on how excess generation in one billing period is to be treated in subsequent billing periods. These changes are not intended to change how net metering has been implemented; we are simply providing clarity so the regulation accurately reflects the Commission’s intent and actual practice.

4. Section 75.13(e)

The re-lettered subsection (e) is being revised to provide clarity on how excess generation amounts are determined at the end of the year and how the compensation is to be computed. These changes are not intended to change how net metering has been implemented; we are simply providing clarity so the regulation accurately reflects the Commission’s intent. The revision makes it clear that only the customer-generator’s excess generation that was not offset by that customer’s usage is to be compensated at the price-to-compare rate. In addition, we make it clear that the EDC/DSP is to use a weighted average of the price-to-compare rate based on the rate in effect when the excess generation was actually delivered. This is intended to compensate the customer-generator in a manner that more accurately represents the value of the excess generation.

5. Section 75.13(f)

The issue in the re-lettered subsection (f) involves the compensation level for customer-generators who exercise the option for retail choice. When a customer shops, they cease to pay the default service provider’s price to compare (which includes all generation and transmission charges) and instead takes this service at a price offered by an EGS.

The current regulation acknowledges this fact, noting that the compensation for kilowatt-hours produced is a matter between an EGS and customer-generator. The regulation merely requires that the terms of the compensation be clearly stated in the service agreement. However, the regulation is silent as to how distribution charges are to be treated by the EDC. Customer-generators who shop are still responsible for the regulated distribution rates of the EDC. Like customer-generators who currently net meter while taking service from the EDC/DSP, customer-generators who take supply service from an EGS shall also receive a credit against the unbundled kilowatt-hour based distribution charges. This credit shall be equal to the unbundled kilowatt-hour distribution charge of the EDC for the customer-generator’s kilowatt-hour rate schedule. As with the generation charges for customer-generators taking EDC/DSP service, any excess kilowatt-hours in any billing period are to be carried forward and credited against the

customer-generator’s kilowatt-hour distribution charges in subsequent billing periods until the end of the year. Any kilowatt-hour distribution credits remaining at the end of the year are zeroed-out such that the customer-generator receives no payments from the EDC, or any remaining kilowatt-hour distribution charge credits into the next year. This language is intended to provide clarity, not to change the current practice under the existing rules.

6. Section 75.13(j)

In the re-lettered subsection (j), we added references to default service and the default service rate. This change simply recognizes DSPs and the role EDCs currently play in providing default service.

7. Section 75.13(k)

In the re-lettered subsection (k), we added references to DSPs and clarify when charges may be applied to customer-generators. The current rule states that an EDC may not charge a customer-generator a fee or other type of charge unless the fee or charge would apply to other customers. This prohibition conflicts with regulation 75.14(e), which states that “[i]f the customer-generator requests virtual meter aggregation, it shall be provided by the EDC at the customer-generator’s expense.” In addition, rule 75.14(e) states that “[t]he customer-generator shall be responsible only for any incremental expense entailed in processing his account on a virtual meter aggregation basis.” The re-lettered subsection (k) now allows EDCs to charge a fee that is specifically authorized under this chapter or by order of the Commission. This is intended to remove any conflicts in the regulations and provide clarity.

C. Net Metering: §§ 75.12 and 75.14. Meters and Metering

We are proposing to clarify the definition of virtual meter aggregation in Section 75.12 and the application of virtual meter aggregation in Section 75.14(e). In addition, we are proposing to revise the definition of year and yearly in Section 75.12.

1. Virtual Meter Aggregation

We are proposing several changes to the provisions regarding virtual meter aggregation to clarify when it is available.⁷ Virtual metering was initially proposed in this regulation for the purpose of facilitating the development of distributed generation in the agricultural setting, particularly for systems referred to as anaerobic or methane biodigesters. The Commission learned that it was not uncommon for a farmer to own multiple, non-contiguous parcels of land that were separately metered to measure the load served at each location. The Commission chose to permit the virtual metering of these parcels to achieve the policy objectives of the AEPS Act:

The fundamental intent of Act is the expansion and increased use of alternative energy systems and energy efficiency practices. Regulatory and economical barriers have been in place that prevented systems such as anaerobic digesters from being more economical or further developed. This rulemaking provides an opportunity to advance the use of these alternative energy systems in a way that will benefit the customer-generator, ratepayers and the environ-

⁷ The amendments proposed in this section include, but are not limited to, the concerns noted by the Commission in *Larry Moyer v. PPL Electric Utilities Corp.*, Opinion and Order, Docket No. C-2011-2273645 at 17-20 (entered January 9, 2014), in which the Commission referred the issue of whether an interconnected alternative energy system qualifies for net or virtual metering if there is no non-generational load at the interconnection point, to the Law Bureau to consider whether the regulations need to be clarified.

ment by allowing exceptions for this important class of customers. Accordingly, we will permit virtual meter aggregation for customer-generators.

As pointed out by the Pennsylvania Farm Bureau, the proposed definition and application of virtual meter aggregation do not fit the reality of a typical Pennsylvania farm operation that has adequate animal units to produce required amounts of manure for anaerobic digesters to operate efficiently. The Pennsylvania Department of Agriculture recently surveyed 26 farms in the state that either have manure digesters operating, digesters under construction or in the planning stages. Out of the 21 farm operations that responded to the survey, there are 148 individual meters involved, which represents an average of seven meters per farm.

Additionally, a study completed by Dr. James Cobb from the University of Pittsburgh, in 2005, titled *Anaerobic Digesters on Dairy Farms*, indicates a potential of 50-60 digesters being developed on Pennsylvania dairy farms in the foreseeable future. The digesters will not be developed to this extent if the proposed metering aggregation restrictions remain in place.

Final Rulemaking Re Net Metering for Customer-Generators Pursuant to Section 5 of the Alternative Energy Portfolio Standards Act, Docket L-00050174 at 21 (Order entered June 22, 2006).

Subsequent to the Commission's 2006 rulemaking, the General Assembly amended the AEPS Act and included the definition for virtual meter aggregation within the definition of net metering in 73 P.S. § 1648.2.⁸ The language in the amended AEPS Act is nearly identical to the language adopted by the Commission in this proposed rulemaking.

Since the Commission's regulations became effective, various parties have presented scenarios to the Commission for virtual metering that do not comport with our intent to permit a limited amount of virtual meter aggregation. This includes fact patterns where distributed generation is proposed to be installed at a location with no load, but then virtually aggregated with another location that has no distributed generation. Another example includes a retail customer hosting distributed generation that it neither owns nor operates and then aggregating it with the distributed generation owned and operated by an entirely different customer at another location within the two mile limit. We, therefore, propose revisions to Sections 75.12 and 75.14 clarify the acceptable scope of virtual metering.

2. Year and Yearly

In the existing regulations, the term year and yearly, as it applies to net metering, is defined as the planning year as determined by the PJM Interconnection, LLC regional transmission organization. The Commission selected this definition initially to avoid confusion, as it is the same as the AEPS Act compliance year of June 1 through May 31.⁹ In implementing these regulations over the last seven years, it has become clear that the vast majority of net metered customer-generator systems are solar photovoltaic systems. We recognize that these solar photovoltaic systems produce their peak outputs during the months of May through September. Accordingly, with

a year ending in May, many of these systems may have excess generation that receives a payment at the price-to-compare rate as opposed to receiving a fully bundled credit toward their subsequent billing periods. Therefore, we propose to revise the definition for year and yearly as it applies to net metering to the period of time from May 1 through April 30.

D. Net Metering: § 75.16. Large Customer-Generators

This section has been added to address distributed generation systems with a nameplate capacity of greater than three megawatts and up to five megawatts, which for purposes of this rulemaking we will refer to as large customer-generators. The AEPS Act states that systems of this size may qualify for customer-generator status if they meet certain conditions, such as being able to support the transmission grid during an emergency, or being part of a microgrid and able to maintain critical infrastructure.

In the existing regulations at 52 Pa. Code § 75.1, the definition for customer-generator found in the Act is repeated word for word. In the proposed section 75.16 we provide clarification so that potential applicants have a reasonable level of certainty that their systems will qualify for customer-generator status before making an investment to purchase and install such a system.

The newly proposed Section 75.16 identifies the standards that must be met to qualify as a large customer-generator. A customer-generator will be considered to be supporting the grid if an RTO, such as PJM, has formally designated it as a resource that the RTO will call upon during a grid emergency. For example, the PJM Operating Agreement and Open Access Transmission Tariff (OATT) identifies certain emergency rules and procedures in which it may call upon generation resources to run at maximum output to provide support during a generation or transmission emergency. These procedures and associated rules are also delineated in PJM's Reliability Assurance Agreement on file with FERC. Should a customer with a distributed generation system of between three megawatts and five megawatts have all or a portion of its system designated an emergency type support resource by an RTO, it may seek qualification as a customer-generator from the Commission. The applicant will have the burden of demonstrating through appropriate documentation that it has been designated by the RTO as a grid support generation resource.

We note that the customer-generator definition requiring the large facilities to operate in parallel with the local utility during grid emergencies or a microgrid is in place to support critical infrastructure implies that a customer-generator is capable of operating off the grid under certain circumstances. In the case of the grid emergency requirement, the generation facility is able to increase generation output supplied to the local grid or remove all output to the local grid during a grid emergency. Thus, entities that own facilities with a nameplate capacity of between three megawatts and up to five megawatts that normally supply most or all of its output to the local utility cannot qualify as a customer-generator as they cannot make their generation available to operate in parallel only during grid emergencies. In contrast, this definition implies that where a microgrid exists to support critical infrastructure, the generating facility can normally supply energy to and operate in parallel with the local utility, but is able to operate off the local utility grid during grid emergencies to support the continued operation of critical infrastructure. For a large distributed generation system may also qualify for customer-generator status if it is part of a microgrid and provides

⁸ See P.L. 114, No. 35 of 2007.

⁹ See Implementation of Act 35 of 2007 Net Metering and Interconnection, Final Omitted Rulemaking Order at Docket No. L-00050174, entered on July 22, 2008 at 11 and 12.

generation to critical infrastructure. Examples of critical infrastructure are provided within the AEPS Act and have been included in the definition of customer-generator in the regulation.

E. Net Metering: § 75.17. Process for Obtaining Commission Approval of Customer-Generator Status.

Since the inception of the AEPS Act and these regulations, the EDCs have been solely responsible for interconnecting and approving net metering for all customer-generators. While this has worked well for EDCs and customer-generators, the Commission has received some reports of inconsistent application of the net metering rules. In addition, as the Commission is imposing a 110 percent of annual load limit on the size of customer-generators, we are proposing a process for seeking Commission approval of all customer-generators with a nameplate capacity of 500 kilowatts or greater.

Under the proposed process, EDCs are to submit completed net metering applications for alternative energy systems with a nameplate capacity of 500 kilowatts or greater to the Commission's Bureau of Technical Utility Services, within 20 days of receiving them, along with a recommendation on whether the proposed alternative energy system complies with these rules and the EDC's net metering tariff. The EDC is to serve its recommendation on the applicant, who has 20 days to submit a response to the Bureau of Technical Utility Services. The Bureau of Technical Utility Services must review the application, EDC recommendation and applicant response and, pursuant to delegated Commission authority, approve or disapprove the application within 30 days of its submission. The Bureau is to describe in detail its reasons for disapproval of an application. The applicant or the EDC may appeal the Bureau's determination to the Commission within 20 days after service of notice in accordance with rule 5.44 (relating to petitions for appeal from actions of staff).

F. Interconnection: § 75.22. Definitions.

The Commission is proposing a revision to the definition for "electric nameplate capacity." Parties have asked for clarification in the solar photovoltaic context as to whether it is the capacity of the panels that should be measured, or that of the inverter that converts the electricity from direct current (DC) to alternating current (AC). For example, while the panels of a particular residential location may have a DC capacity of 50 kW, the inverter may only be able to convert a maximum of 45 kW to AC. The other five kW is lost in the conversion process.

The Commission has been asked to designate the capacity limit as that of the inverter to enable customer-generators to maximize their output and possible compensation. Accordingly, under the above fact pattern, a residential customer might install panels with 55 kW of DC capacity, but so long as the inverter's AC capacity was no greater than 50 kW, it would qualify as a customer-generator.

The AEPS Act describes a customer-generator in the residential context as the owner or operator of a "net-metered distributed generation system with a nameplate capacity of not greater than 50 kilowatts." See 73 P. S. § 1648.2. The key word in this description is "system." The definition does not refer to individual components of a generator, such as panels or inverters, but to the entire generation system. Therefore, the Commission finds that as the General Assembly referred to the distributed generation system, the General Assembly intended for

customer-generators to have the full benefit of the capacity capabilities of the entire generation system, which in the case of a solar photovoltaic system is the output at the inverter, not the panels. Therefore, electric nameplate capacity will be revised to refer to the limits of the inverter or inverters (if more than one is needed) at a particular customer-generator location, as opposed to the generation device.

G. Interconnection: §§ 75.31, 75.34, 75.39, and 75.40. Capacity Limits.

These sections have been revised to reflect the increase of the capacity limit resulting from Act 35 for customer-generators from 2 MW to 5 MW.

H. Interconnection: § 75.51. Disputes.

The current regulations at § 75.51(c) provides that the Commission may designate a Department of Energy National Laboratory, PJM Interconnection L.L.C., or college or university with distribution system engineering expertise as a technical master. Once the Commission designates a technical master, the parties to a dispute are to use the technical master to help resolve the dispute.

To date the Commission has not designated a technical master. This is due to the fact that there are costs involved in identifying and retaining such expertise, which are not justified by the number of disputes. To date we are not aware of any interconnection disputes that have not been resolved through the normal Commission complaint or alternative dispute resolution processes. As such, we are proposing to delete this subsection.

I. Alternative Energy Portfolio Requirement: § 75.61. EDC and EGS Obligations.

This section has been revised to note that the requirements are subject to the quarterly adjustment provisions of Act 129 of 2008. See 66 Pa.C.S. § 2814(c).

J. Alternative Energy Portfolio Requirement: § 75.62. Alternative Energy System Qualification.

Section 75.62(g) has been added to note that alternative energy system status may be suspended or revoked for violations of the provisions of this chapter. The penalty provision is primarily intended to discourage and, if necessary, punish fraudulent behavior by owners of alternative energy systems. While this authority was implied in the current regulations, we propose adding this provision to make this authority explicit to provide clarity.

K. Alternative Energy Portfolio Requirement: § 75.63. Alternative Energy Credit Certification.

Section 75.63(g) has been supplemented with a proposed end to the use of estimates for future small solar photovoltaic systems and to clarify when estimated readings may be used by existing small solar photovoltaic systems. To begin with, the revision provides that small solar photovoltaic systems installed or that increase capacity on or after 180 days from the effective date of the regulation must use metered data to verify alternative energy credit certification. In adopting the current regulations, we allowed for the use of estimates for small solar photovoltaic systems of 15 kilowatts or less to reduce the cost of installing and operating such systems. Since then, the cost of solar photovoltaic panels have decreased such that the minimal cost of a revenue grade meter no longer provides a barrier to the installation of these small systems. As such, we propose to require all new solar photovoltaic systems to have a revenue grade meter to measure system output for alternative energy credit certification.

The other revisions to Section 75.63(g) provides that estimated reads may be used for existing small solar photovoltaic systems only when no other technology is available, and that once actual metered data begins to be used, estimates are no longer permitted. The revision also prevents estimated data in the context of panels whose orientation can be manually adjusted by the owner/operator, given the problems associated with production verification in this circumstance. Finally, the revisions define the solar modules that are eligible for use with estimates and provide the program administrator express authority to verify the output of those systems.

Three additional subsections have been added in order to resolve issues that have been identified in implementation of the Act. Subsection (i) has been added to clarify that credits can be certified from the time the application is filed with the Commission, so long as either metered data is available, or an inverter reading is included when PV Watts estimates are permitted to be used. This is done to avoid penalizing an applicant for the time it takes the administrator to review and approve the application.

Subsection (j) is being proposed to address incomplete or incorrect applications. The Commission's preference is that the program administrator give an applicant a reasonable period of time, at the administrator's discretion depending on the nature of the issue, to correct the deficiency before rejecting the application. When an application is rejected, the applicant is penalized because it loses the opportunity to earn credits for the period when the application was first filed to the time when it was rejected. Credits may only be earned from the time of the filing of the second application. This section puts applicants on notice of the importance of filing a complete and correct application, the need to timely respond to the administrator's notice to them, and the penalty for failing to do so.

Subsection (k) has been added to resolve an ambiguity over the vintage of alternative energy credits. Generally, credits may only be banked for use for two years. It is therefore necessary that the right vintage year be assigned to a credit, as documented by the certificate created in PJM-EIS's credit registry, the Generator Attribute Tracking System (GATS). Sometimes data may be entered in the credit registry for production that overlaps two different reporting periods. This section confirms that credits will be allocated to the appropriate reporting period, regardless of when the data is entered into the credit registry.

L. Alternative Energy Portfolio Requirement: § 75.64. Alternative Energy Credit Program Administrator.

We have added provisions to Section 75.64(b) to note that alternative energy system status may be suspended or revoked and that the credits from a suspended or revoked system may be withheld or retired for violations of the provisions of this chapter. The penalty provision is primarily intended to discourage, and if necessary, punish, fraudulent behavior by owners or aggregators of alternative energy systems. While this authority was implied in the current regulations, we propose adding this provision to make this authority explicit to provide clarity.

In Section 75.64(c) we have proposed revisions that more accurately reflect the current reporting requirements, timing and processes for determining and verifying EDC and EGS compliance with the AEPS Act obligations.

Finally, in Section 75.64(d) we have proposed a provision that expressly states that the program administrator

may not certify an alternative energy credit that does not meet the requirements of § 75.63 (relating to alternative energy credit certification). This provision is being proposed to provide explicit authority to the program administrator that was previously implied.

M. Alternative Energy Portfolio Requirement: § 75.65. Alternative Compliance Payments.

In this section we are clearly identifying the Commission's Bureau of Technical Utility Services as the Bureau with the responsibility of providing notice of and processing alternative compliance payments.

N. Alternative Energy Portfolio Requirement: §§ 75.71 and 75.72. Quarterly Adjustment of Non-Solar Tier I Obligation.

In 2008, the General Assembly again amended the AEPS Act¹⁰ by adding two new Tier I resources and requiring the Commission to increase the percentage share of Tier I requirements on a quarterly basis to reflect the addition of the new Tier I resources, which was codified in 66 Pa.C.S. § 2814. The Commission issued an Order to implement the AEPS related provisions of Act 129 in 2009. See, Implementation of Act 129 of 2008 Phase 4—Relating to the Alternative Energy Portfolio Standards Act, Docket M-2009-2093383 (Order entered May 28, 2009). This rulemaking will also codify the processes and standards identified in that Order in this Chapter at Sections 75.71 and 75.72.

Regulatory Review

Under section 5(a) of the Regulatory Review Act (71 P. S. § 745.5(a)), on June 23, 2014, the Commission submitted a copy of this proposed rulemaking and a copy of a Regulatory Analysis Form to the Independent Regulatory Review Commission (IRRC) and to the Chairpersons of the House Consumer Affairs Committee and the Senate Consumer Protection and Professional Licensure Committee. A copy of this material is available to the public upon request.

Under section 5(g) of the Regulatory Review Act, IRRC may convey any comments, recommendations or objections to the proposed rulemaking within 30 days of the close of the public comment period. The comments, recommendations or objections must specify the regulatory review criteria which have not been met. The Regulatory Review Act specifies detailed procedures for review, prior to final publication of the rulemaking, by the Commission, the General Assembly and the Governor of comments, recommendations or objections raised.

Conclusion

Accordingly, under 66 Pa.C.S. §§ 501, 1501 and 2807(e), sections 1648.7(a) and 1648.3(e)(2) of the Alternative Energy Portfolio Standards Act of 2004 (73 P. S. §§ 1648.7(a) and 1648.3(e)(2)); the Commonwealth Documents Law (45 P. S. §§ 1201 et seq.), and the regulations promulgated thereunder at 1 Pa. Code §§ 7.1, 7.2 and 7.5, the Commission proposes revisions to its regulations pertaining to the alternative energy portfolio standard obligation, and its provisions for net metering and interconnection, as noted and set forth in Annex A; *Therefore,*

It Is Ordered That:

1. The Proposed Rulemaking at Docket L-2014-2404361 will consider the regulations set forth in Annex A.
2. The Secretary shall submit this order and Annex A to the Office of Attorney General for approval as to legality.

¹⁰ See P. L. 1592, No. 129 of 2008.

3. The Secretary shall submit this order and Annex A to the Governor’s Budget Office for review of fiscal impact.

4. The Secretary shall submit this order and Annex A for review by the designated standing committees of both houses of the General Assembly, and for review by the Independent Regulatory Review Commission.

5. A copy of this order and Annex be served on the Pennsylvania Department of Environmental Protection, all jurisdictional electric distribution companies, the Office of Consumer Advocate, the Office of Small Business Advocate, the Commission’s Bureau of Investigation and Enforcement, the Energy Association of Pennsylvania, the Retail Energy Supply Association and the parties in the matter of *Larry Moyer v. PPL Electric Utilities Corp.*, at Docket No. C-2011-2273645.

6. The Secretary shall deposit this order and Annex A with the Legislative Reference Bureau for publication in the *Pennsylvania Bulletin*.

7. An original of written comments referencing the docket number of the proposed rulemaking shall be submitted within 30 days of publication in the *Pennsylvania Bulletin* to the Pennsylvania Public Utility Commission, Attn: Secretary, P.O. Box 3265, Harrisburg, PA 17105-3265.

8. The contact person for technical issues related to this rulemaking is Scott Gebhardt, Bureau of Technical Utility Services, (717) 787-2139. That the contact person for legal issues related to this rulemaking is Kriss Brown, Assistant Counsel, Law Bureau, (717) 787-4518. Alternate formats of this document are available to persons with disabilities and may be obtained by contacting Sherri Delbiondo, Regulatory Coordinator, Law Bureau, (717) 772-4597.

ROSEMARY CHIAVETTA,
Secretary

Fiscal Note: 57-304. No fiscal impact; (8) recommends adoption.

Annex A

TITLE 52. PUBLIC UTILITIES
PART I. PUBLIC UTILITY COMMISSION
Subpart C. FIXED SERVICE UTILITIES
CHAPTER 75. ALTERNATIVE ENERGY PORTFOLIO STANDARDS
Subchapter A. GENERAL PROVISIONS

§ 75.1. Definitions.

The following words and terms, when used in this chapter, have the following meanings unless the context clearly indicates otherwise:

Act—The Alternative Energy Portfolio Standards Act (73 P. S. §§ 1648.1—1648.8).

Aggregator—A person or entity that maintains a contract with an individual alternative energy system owner to facilitate the sale of alternative energy credits on behalf of multiple alternative energy system owners.

Alternative energy credit—A tradable instrument that is used to establish, verify and monitor compliance with the act. A unit of credit must equal 1 megawatt hour of electricity from an alternative energy source. An alternative energy credit shall remain the property of the

alternative energy system until the alternative energy credit is voluntarily transferred by the alternative energy system.

Alternative energy sources—The term includes the following existing and new sources for the production of electricity:

* * * * *

(v) Low-impact hydropower consisting of any technology that produces electric power and that harnesses the hydroelectric potential of moving water impoundments[, **provided the incremental hydroelectric development] if one of the following applies:**

(A) The hydropower source has a Federal Energy Regulatory Commission (FERC) licensed capacity of 21 MW or less and was issued its license by January 1, 1984, and was held on July 1, 2007, in whole or in part, by a municipality located wholly within this Commonwealth or by an electric cooperative incorporated in this Commonwealth.

(B) The incremental hydroelectric development:

[(A)] (I) Does not adversely change existing impacts to aquatic systems.

[(B)] (II) Meets the certification standards established by the low impact hydropower institute and American Rivers, Inc., or their successors.

[(C)] (III) Provides an adequate water flow for protection of aquatic life and for safe and effective fish passage.

[(D)] (IV) Protects against erosion.

[(E)] (V) Protects cultural and historic resources.

(vi) Geothermal energy, which means electricity produced by extracting hot water or steam from geothermal reserves in the earth’s crust and supplied to steam turbines that drive generators to produce electricity.

(vii) Biomass energy, which means the generation of electricity utilizing the following:

(A) Organic material from a plant that is grown for the purpose of being used to produce electricity or is protected by the Federal Conservation Reserve Program (CRP) and provided further that crop production on CRP lands does not prevent the achievement of the water quality protection, soil erosion prevention or wildlife enhancement purposes for which the land was primarily set aside.

(B) Solid nonhazardous, cellulosic waste material that is segregated from other waste materials, such as waste pallets, crates and landscape or right-of-way tree trimmings or agricultural sources, including orchard tree crops, vineyards, grain, legumes, sugar and other byproducts or residues.

(C) 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 from alternative energy systems located in this Commonwealth.

(viii) Biologically derived methane gas, which includes methane from the anaerobic digestion of organic materials from yard waste, such as grass clippings and leaves, food waste, animal waste and sewage sludge. The term also includes landfill methane gas.

* * * * *

(xiii) Distributed generation systems, which means the small-scale power generation of electricity and useful thermal energy from systems with a nameplate capacity not greater than 5 MW.

* * * * *

Customer-generator—A retail electric customer that is a nonutility owner or operator of a net metered distributed generation system with a nameplate capacity of not greater than 50 kilowatts if installed at a residential service or not larger than 3,000 kilowatts at other customer service locations, except for customers whose systems are above 3 megawatts and up to 5 megawatts who make their systems available to operate in parallel with the electric utility during grid emergencies as defined by the regional transmission organization or where a microgrid is in place for the primary or secondary purpose of maintaining critical infrastructure, such as homeland security assignments, emergency services facilities, hospitals, traffic signals, wastewater treatment plants or telecommunications facilities, provided that technical rules for operating generators interconnected with facilities of an EDC, electric cooperative or municipal electric system have been promulgated by the institute of electrical and electronic engineers and the Commission.

DSP—Default service provider—An EDC within its certified service territory or an alternative supplier approved by the Commission that provides generation service when one of the following conditions occurs:

(i) A contract for electric power, including energy and capacity, and the chosen EGS does not supply the service to a retail electric customer.

(ii) A retail electric customer does not choose an alternative EGS.

Department—The Department of Environmental Protection of the Commonwealth.

* * * * *

Force majeure—

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(iv) If the Commission modifies the EDC or EGS obligations under the act, the Commission may require the EDC or EGS to acquire additional alternative energy credits in subsequent years equivalent to the obligation reduced by a force majeure declaration when the Commission determines that sufficient alternative energy credits exist in the marketplace.

Grid emergencies—One of the following abnormal system conditions:

(i) Manual or automatic action to maintain system frequency to prevent loss of firm load, equipment damage or tripping of system elements that could adversely affect the reliability of an electric system or the safety of persons or property.

(ii) Capacity deficiency or capacity excess conditions.

(iii) A fuel shortage requiring departure from normal operating procedures to minimize the use of the scarce fuel.

(iv) An abnormal natural event or manmade threat that would require conservative operations to posture the system in a more reliable state.

(v) An abnormal event external to the PJM service territory that may require PJM action.

kW—Kilowatt—A unit of power representing 1,000 watts. A kW equals 1/1000 of a MW.

MW—Megawatt—A unit of power representing 1,000,000 watts. An MW equals 1,000 kW.

Microgrid—A system analogous to the term distributed resources (DR) island system, when parts of the electric grid that have DR and load have the ability to intentionally disconnect from and operate in parallel with electric power systems.

Moving water impoundment—A physical feature that confines, restricts, diverts or channels the flow of surface water, including in-stream hydroelectric generating technology and equipment.

Municipal solid waste—The term includes energy from existing waste to energy facilities which the Department has determined are in compliance with current environmental standards, including the applicable requirements of the Clean Air Act (42 U.S.C.A. §§ 7401–7671g) and associated permit restrictions and the applicable requirements of the Solid Waste Management Act (35 P.S. §§ 6018.101–6018.1003).

RTO—Regional transmission organization—An entity approved by the [Federal Energy Regulatory Commission (FERC)] FERC that is created to operate and manage the electrical transmission grids of the member electric transmission utilities as required under FERC Order 2000, Docket No. RM99-2-000, FERC Chapter 31.089 (1999) or any successor organization approved by the FERC.

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Tier II alternative energy source—Energy derived from:

* * * * *

(vi) 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 from alternative energy systems located outside this Commonwealth.

(vii) Integrated combined coal gasification technology.

True-up period—The period each year from the end of the reporting year until September 1.

Useful thermal energy—

(i) Thermal energy created from the production of electricity which would otherwise be wasted if not used for other nonelectric generation, beneficial purposes.

(ii) The term does not apply to the use of thermal energy used in combined-cycle electric generation facilities.

Utility—A person or entity that provides electric generation, transmission or distribution services, at wholesale or retail, to other persons or entities.

Subchapter B. NET METERING

§ 75.12. Definitions.

The following words and terms, when used in this subchapter, have the following meanings unless the context clearly indicates otherwise:

* * * * *

Virtual meter aggregation—The combination of readings and billing for all meters regardless of rate class on properties owned or leased and operated by a customer-generator by means of the EDC's billing process, rather than through physical rewiring of the customer-generator's property for a physical, single point of contact. Virtual meter aggregation on properties owned or leased and operated by [a] **the same** customer-generator and located within 2 miles of the boundaries of the customer-generator's property and within a single [**electric distribution company's**] EDC's service territory shall be eligible for net metering. **Service locations to be aggregated must be receiving retail electric service from the same EDC and have measureable electric load independent of the alternative energy system. To be independent of the alternative energy system, the electric load must have a purpose other than to support the operation, maintenance or administration of the alternative energy system.**

Year and yearly—[**Planning year as determined by the PJM Interconnection, LLC regional transmission organization.**] The period of time from May 1 through April 30.

§ 75.13. General provisions.

(a) EDCs and DSPs shall offer net metering to customer-generators that generate electricity on the customer-generator's side of the meter using Tier I or Tier II alternative energy sources, on a first come, first served basis. **To qualify for net metering, the customer-generator shall meet the following conditions:**

(1) **Have electric load, independent of the alternative energy system, behind the meter and point of interconnection of the alternative energy system. To be independent of the alternative energy system, the electric load must have a purpose other than to support the operation, maintenance or administration of the alternative energy system.**

(2) **The owner or operator of the alternative energy system may not be a utility.**

(3) **The alternative energy system must be sized to generate no more than 110% of the customer-generator's annual electric consumption at the interconnection meter location when combined with all qualifying virtual meter aggregation locations.**

(4) **The alternative energy system must have a nameplate capacity of not greater than 50 kW if installed at a residential service location.**

(5) **The alternative energy system must have a nameplate capacity not larger than 3 MW at other customer service locations.**

(6) **The alternative energy system must have a nameplate capacity not larger than 5 MW and meets the conditions in § 75.16 (relating to large customer-generators).**

(7) **An alternative energy system with a nameplate capacity of 500 kW or more must have Commission approval for net metering in accordance with § 75.17 (relating to process for obtaining Commission approval of customer-generator status).**

(b) EGSs may offer net metering to customer-generators, on a first come, first served basis, under the terms and conditions as are set forth in agreements between EGSs and customer-generators taking service from EGSs, or as directed by the Commission.

[(b)] (c) An EDC shall file a tariff with the Commission that provides for net metering consistent with this chapter. An EDC shall file a tariff providing net metering protocols that enable EGSs to offer net metering to customer-generators taking service from EGSs. To the extent that an EGS offers net metering service, the EGS shall prepare information about net metering consistent with this chapter and provide that information with the disclosure information required in § 54.5 (relating to disclosure statement for residential and small business customers).

[(c) The EDC] (d) An EDC and DSP shall credit a customer-generator at the full retail rate, which shall include generation, transmission and distribution charges, for each kilowatt-hour produced by a Tier I or Tier II resource installed on the customer-generator's side of the electric revenue meter, up to the total amount of electricity used by that customer during the billing period. If a [**customer generator**] **customer-generator** supplies more electricity to the electric distribution system than the EDC [**delivers**] and DSP **deliver** to the customer-generator in a given billing period, the excess kilowatt hours shall be carried forward and credited against the customer-generator's usage in subsequent billing periods at the full retail rate. Any excess kilowatt hours **that are not offset by electricity used by the customer in subsequent billing periods** shall continue to accumulate until the end of the year. For customer-generators involved in virtual meter aggregation programs, a credit shall be applied first to the meter through which the generating facility supplies electricity to the distribution system, then through the remaining meters for the customer-generator's account equally at each meter's designated rate.

[(d)] (e) At the end of each year, the [**EDC**] DSP shall compensate the customer-generator for any **remaining** excess kilowatt-hours generated by the customer-generator [**over the amount of kilowatt hours delivered by the EDC during the same year**] that were not previously credited against the customer-generator's usage in prior billing periods at the EDC's price to compare rate. **In computing the compensation, the DSP shall use a weighted average of the price to compare rate with the weighting based on the rate in effect when the excess generation was actually delivered by the customer-generator to the DSP.**

[(e)] (f) The credit or compensation terms for excess electricity produced by customer-generators who are customers of EGSs shall be stated in the service agreement between the customer-generator and the EGS. **EDCs shall credit customer-generators who are EGS customers for each kilowatt-hour of electricity produced at the EDC's unbundled distribution kilowatt-hour rate. The distribution credit shall be applied monthly. If the customer-generator supplies more electricity to the electric distribution system than the EDC delivers to the customer-generator in any billing period, the excess kilowatt hours shall be carried forward and credited against the customer-generator's unbundled distribution usage in subsequent billing periods until the end of the year when all remaining unused distribution credits shall be zeroed-out. Distribution credits are not carried forward into the next year.**

[(f)] (g) If a customer-generator switches electricity suppliers, the EDC shall treat the end of the service period as if it were the end of the year.

[(g)] (h) An EDC and EGS which offer net metering shall submit an annual net metering report to the Commission. The report shall be submitted by July 30 of each year, and include the following information for the reporting period ending May 31 of that year:

- (1) The total number of customer-generator facilities.
- (2) The total estimated rated generating capacity of its net metering customer-generators.

[(h)] (i) A customer-generator that is eligible for net metering owns the alternative energy credits of the electricity it generates, unless there is a contract with an express provision that assigns ownership of the alternative energy credits to another entity or the customer-generator expressly rejects any ownership interest in alternative energy credits under § 75.14(d) (relating to meters and metering).

[(i)] (j) An EDC and DSP shall provide net metering at nondiscriminatory rates identical with respect to rate structure, retail rate components and any monthly charges to the rates charged to other customers that are not customer-generators **on the same default service rate**. An EDC and DSP may use a special load profile for the customer-generator which incorporates the customer-generator's real time generation if the special load profile is approved by the Commission.

[(j)] (k) An EDC or DSP may not charge a customer-generator a fee or other type of charge unless the fee or charge would apply to other customers that are not customer-generators, **or is specifically authorized under this chapter or by order of the Commission**. The EDC and DSP may not require additional equipment or insurance or impose any other requirement unless the additional equipment, insurance or other requirement is specifically authorized under this chapter or by order of the Commission.

[(k)] (l) Nothing in this subchapter abrogates a person's obligation to comply with other applicable law.

§ 75.14. Meters and metering.

* * * * *

(e) Virtual meter aggregation on properties owned or leased and operated by [a] **the same** customer-generator shall be allowed for purposes of net metering. Virtual meter aggregation shall be limited to meters located on properties owned or leased and operated by **the same customer-generator** within 2 miles of the boundaries of the customer-generator's property and within a single EDC's service territory. **All properties to be aggregated must be receiving electric generation service and have measureable load independent of any alternative energy system**. Physical meter aggregation shall be at the customer-generator's expense. The EDC shall provide the necessary equipment to complete physical aggregation. If the customer-generator requests virtual meter aggregation, it shall be provided by the EDC at the customer-generator's expense. The customer-generator shall be responsible only for any incremental expense entailed in processing his account on a virtual meter aggregation basis.

* * * * *

(Editor's Note: Sections 75.16 and 75.17 are new and printed in regular type to enhance readability.)

§ 75.16. Large customer-generators.

(a) This section applies to distributed generation systems with a nameplate capacity above 3 MW and up to 5 MW. The section identifies the standards that distributed generation systems must satisfy to qualify for customer-generator status.

(b) A retail electric customer may qualify its alternative energy system for customer-generator status if it makes its system available to operate in parallel with the grid during grid emergencies by satisfying the following requirements:

(1) An RTO has designated, under a Federal Energy Regulatory Commission approved tariff or agreement, the alternative energy system as a generation resource that may be called upon to respond to grid emergencies.

(2) The alternative energy system is able to provide the emergency support consistent with the tariff or agreement.

(3) The alternative energy system is able to increase and decrease generation delivered to the distribution system in parallel with the EDC's operation of the distribution system during the grid emergency.

(c) A retail electric customer may qualify its alternative energy system located within a microgrid for customer-generator status if it satisfies the following requirements:

(1) The alternative energy system complies with IEEE Standard 1547.4.

(2) The customer documents that the alternative energy system exists for the primary or secondary purpose of maintaining critical infrastructure.

§ 75.17. Process for obtaining Commission approval of customer-generator status.

(a) This section establishes the process through which EDCs obtain Commission approval to net meter alternative energy systems with a nameplate capacity of 500 kW or greater.

(b) An EDC shall submit a completed net metering application to the Commission's Bureau of Technical Utility Services with a recommendation on whether the alternative energy system complies with the applicable provisions of this chapter and the EDC's net metering tariff provisions within 20 days of receiving a completed application. The EDC shall serve its recommendation on the applicant.

(c) The net metering applicant has 20 days to submit a response to the EDC's recommendation to the Bureau of Technical Utility Services.

(d) The Bureau of Technical Utility Services will review the net metering application, the EDC recommendation and response, and make a determination as to whether the alternative energy system complies with this chapter and the EDC's net metering tariff.

(e) The Bureau of Technical Utility Services will approve or disapprove the net metering application within 30 days of submission and describe in detail the reasons for disapproval. The Bureau of Technical Utility Services will serve its determination on the EDC and the applicant.

(f) The applicant and the EDC may appeal the determination of the Bureau of Technical Utility Services in accordance with § 5.44 (relating to petitions for reconsideration from actions of the staff).

Subchapter C. INTERCONNECTION STANDARDS
GENERAL

§ 75.22. Definitions.

The following words and terms, when used in this subchapter, have the following meanings unless the context clearly indicates otherwise:

* * * * *

Electric nameplate capacity—The net maximum or net instantaneous peak electric output [**capability**] **capacity** measured in volt-amps of a small generator facility, **the inverter or the aggregated capacity of multiple inverters at an alternative energy systems location** as designated by the manufacturer.

* * * * *

INTERCONNECTION PROVISIONS

§ 75.31. Applicability.

The interconnection procedures apply to customer-generators with small generator facilities that satisfy the following criteria:

(1) The electric nameplate capacity of the small generator facility is equal to or less than [**2**] **5** MW.

* * * * *

§ 75.34. Review procedures.

An EDC shall review interconnection requests using one or more of the following four review procedures:

* * * * *

(2) An EDC shall use Level 2 procedures for evaluating interconnection requests to connect small generation facilities when:

(i) The small generator facility uses an inverter for interconnection.

(ii) The electric nameplate capacity rating is [**2**] **5** MW or less.

(iii) The customer interconnection equipment proposed for the small generator facility is certified.

(iv) The proposed interconnection is to a radial distribution circuit, or a spot network limited to serving one customer.

(v) The small generator facility was reviewed under Level 1 review procedures but not approved.

(3) An EDC shall use Level 3 review procedures for evaluating interconnection requests to connect small generation facilities with an electric nameplate capacity of [**2**] **5** MW or less which do not qualify under Level 1 or Level 2 interconnection review procedures or which have been reviewed under Level 1 or Level 2 review procedures, but have not been approved for interconnection.

* * * * *

§ 75.39. Level 3 interconnection review.

(a) Each EDC shall adopt the Level 3 interconnection review procedure in this section. An EDC shall use the Level 3 review procedure to evaluate interconnection requests that meet the following criteria and for interconnection requests considered but not approved under a Level 2 or a Level 4 review if the interconnection customer submits a new interconnection request for consideration under Level 3:

(1) The small generator facility has an electric nameplate capacity that is [**2**] **5** MW or less.

(2) The small generator facility is less than [**2**] **5** MW and not certified.

(3) The small generator facility is less than [**2**] **5** MW and noninverter based.

* * * * *

§ 75.40. Level 4 interconnection review.

* * * * *

(d) When interconnection to circuits that are not networked is requested, upon the mutual agreement of the EDC and the interconnection customer, the EDC may use the Level 4 review procedure for an interconnection request to interconnect a small generator facility that meets the following criteria:

(1) The small generator facility has an electric nameplate capacity of [**2**] **5** MW or less.

(2) The aggregated total of the electric nameplate capacity of all of the generators on the circuit, including the proposed small generator facility, is [**2**] **5** MW or less.

* * * * *

DISPUTE RESOLUTION

§ 75.51. Disputes.

* * * * *

(c) When disputes relate to the technical application of this chapter, the Commission may designate a technical master to resolve the dispute. The Commission may designate a Department of Energy National laboratory, PJM Interconnection L.L.C., or a college or university with distribution system engineering expertise as the technical master. When the Federal Energy Regulatory Commission identifies a National technical dispute resolution team, the Commission may designate the team as its technical master. Upon Commission designation, the parties shall use the technical master to resolve disputes related to interconnection. Costs for dispute resolution conducted by the technical master shall be determined by the technical master subject to review by the Commission.

(d)] (c) Pursuit of dispute resolution may not affect an interconnection applicant with regard to consideration of an interconnection request or an interconnection applicant's position in the EDC's interconnection queue.

Subchapter D. ALTERNATIVE ENERGY
PORTFOLIO REQUIREMENT

§ 75.61. EDC and EGS obligations.

* * * * *

(b) For each reporting period, EDCs and EGSs shall acquire alternative energy credits in quantities equal to a percentage of their total retail sales of electricity to all retail electric customers for that reporting period, as measured in MWh. The credit obligation for a reporting period shall be rounded to the nearest whole number. The required quantities of alternative energy credits for each reporting period are identified in the following schedule, **subject to the quarterly adjustment of the nonsolar Tier I obligation under § 75.71 (relating to quarterly adjustment of nonsolar Tier I obligation):**

* * * * *

§ 75.62. Alternative energy system qualification.

* * * * *

(f) A facility may not be qualified unless the Department has verified compliance with applicable environmental regulations, and the standards set forth in section 2 of the act (73 P. S. § 1648.2).

(g) A facility's alternative energy system status may be suspended or revoked for noncompliance with this chapter, including the following circumstances:

(1) Providing false information to the Commission, credit registry or program administrator.

(2) Department notification to the Commission of violations of standards in section 2 of the act.

§ 75.63. Alternative energy credit certification.

* * * * *

(g) For solar photovoltaic alternative energy systems with a nameplate capacity of 15 [kilowatts] kW or less that are installed or that increase nameplate capacity on or after _____ (Editor's Note: The blank refers to 180 days after the effective date of adoption of this proposed rulemaking.), alternative energy credit certification shall be verified by the administrator designated under § 75.64 using metered data. For solar photovoltaic alternative energy systems with a nameplate capacity of 15 kW or less that are installed before _____, (Editor's Note: The blank refers to 180 days after the effective date of adoption of this proposed rulemaking.) alternative energy credit certification shall be verified by the administrator using either metered data or estimates. The use of estimates is subject to the following conditions:

(1) A revenue grade meter has not been installed to measure the output of the alternative energy system.

(2) The alternative energy system has not used actual meter or other monitoring system readings for determining system output in the past.

(3) The solar photovoltaic alternative energy system has either a fixed solar orientation or a one-axis or two-axis automated solar tracking system.

(4) The solar photovoltaic alternative energy system is comprised of crystalline silicon modules or a type of module that meets the criteria of the program used by the program administrator to calculate the estimates.

(5) The program administrator has deemed the solar photovoltaic alternative energy system eligible to utilize estimates based on the verified output of the alternative energy system.

(h) An alternative energy credit represents the attributes of 1 MWh of electric generation that may be used to satisfy the requirements of § 75.61 (relating to EDC and EGS obligations). The alternative energy credit shall remain the property of the alternative energy system until voluntarily transferred. A certified alternative energy credit does not automatically include environmental, emissions or other attributes associated with 1 MWh of electric generation. Parties may bundle the attributes unrelated to compliance with § 75.61 with an alternative energy credit, or, alternatively, sell, assign, or trade them separately.

(i) An alternative energy system may begin to earn alternative energy credits on the date a complete application is filed with the administrator, provided that a meter or inverter reading is included with the application.

(j) An alternative energy system application may be rejected if the applicant does not respond to a program administrator request for information or data within 90 days. An application that is not approved within 180 days of its submission due to the applicant's failure to provide information or data to the program administrator will be deemed rejected unless affirmatively held open by the program administrator.

(k) Alternative energy system generation or conservation data entered into the credit registry will be allocated to the compliance year in which the generation or conservation occurred to ensure that alternative energy credits are certified with the correct vintage year.

§ 75.64. Alternative energy credit program administrator.

* * * * *

(b) The program administrator will have the following powers and duties in regard to alternative energy system qualification:

* * * * *

(5) The program administrator will provide written notice to applicants of its qualification decision within 30 days of receipt of a complete application form.

(6) The program administrator may suspend or revoke the qualification of an alternative energy system and withhold or retire past, current or future alternative energy credits attributed to an alternative energy system for noncompliance with this chapter, including the following circumstances:

(i) It no longer satisfies the alternative energy system qualification standards in § 75.62.

(ii) The owner or aggregator of the alternative energy system provides false or incorrect information in an application.

(iii) The owner or aggregator of the alternative energy system fails to notify the program administrator of changes to the alternative energy system that effect the alternative energy system's generation output.

(iv) The owner or aggregator of the alternative energy system fails to notify the program administrator of a change in ownership or aggregator of the alternative energy system.

(v) The owner or aggregator provides false or inaccurate information to the credit registry.

(vi) The owner or aggregator fails to respond to data and information requests from the Commission, Department or program administrator.

(c) The program administrator shall have the following powers and duties regarding the verification of compliance with this chapter:

(1) At the end of each reporting period, the program administrator shall verify the EDC and EGS [compliance with § 75.61 (relating to EDC and EGS obligations)] reported load, and provide written notice to each EDC and EGS [of an initial assessment of

their] of its compliance [status] obligations within 45 days of the end of the reporting period.

(2) At the end of each true-up period, the administrator shall verify compliance with § 75.61 (relating to EDC and EGS obligations) for all EDCs and EGSs [who were in violation of § 75.61 at the end of the reporting period]. The administrator will provide written notice to each EDC and EGS of a final assessment of [their] its compliance status within [15] 45 days of the end of the true-up period.

(3) EDCs and EGSs shall provide all information to the program administrator necessary to verify compliance with § 75.61 including the prices paid for the alternative energy credits used for compliance. The pricing information must include a per credit price for any credits used for compliance that were not self-generated or bundled with energy.

(4) The program administrator shall provide a report to the [Commission] Commission's Bureau of Technical Utility Services within 45 days of the end of [each reporting period and] the true-up period that identifies the compliance status of all EDCs and EGSs. The report provided after the end of the true-up period shall propose alternative compliance payment amounts for each EDC and EGS that is noncompliant with § 75.61 for that reporting period. As part of this report, the administrator shall identify the average market value of alternative energy credits derived from solar photovoltaic energy sold in the reporting period for each RTO that manages a portion of this Commonwealth's transmission system.

(d) The program administrator shall have the following powers and duties relating to alternative energy credit certification:

(1) The program administrator may not certify an alternative energy credit already purchased by individuals, businesses or government bodies that do not have a compliance obligation under the act unless the individual, business or government body sells those credits to the EDC or EGS.

(2) The program administrator may not certify an alternative energy credit for a MWh of electricity generation or electricity conservation that has already been used to satisfy another state's renewable energy portfolio standard, alternative energy portfolio standard or other comparable standard.

(3) The program administrator may not certify an alternative energy credit that does not meet the requirements of § 75.63 (relating to alternative energy credit certification).

(e) A decision of the program administrator may be appealed consistent with § 5.44 (relating to petitions for [appeal] reconsideration from actions of the staff).

* * * * *

§ 75.65. Alternative compliance payments.

(a) Within 15 days of receipt of the report identified in § 75.64(c)(4) (relating to alternative energy credit program administrator), the [Commission] Commission's Bureau of Technical Utility Services will provide written notice to each EDC and EGS that was noncompliant with § 75.61 (relating to EDC and EGS obligations) of their alternative compliance payment for that reporting period.

* * * * *

(c) EDCs and EGSs shall advise the [Commission] Bureau of Technical Utility Services in writing within 15 days of the issuance of this notice of their acceptance of the alternative compliance payment determination or, if they wish to contest the determination, file a petition to modify the level of the alternative compliance payment. The petition must include documentation supporting the proposed modification. The [Commission] Bureau of Technical Utility Services will refer the petition to the [Office of Administrative Law Judge] Commission's Bureau of Investigation and Enforcement for further [proceedings] actions as may be [necessary] warranted. Failure of an EDC or EGS to respond to the [Commission] Bureau of Technical Utility Services within 15 days of the issuance of this notice shall be deemed an acceptance of the alternative compliance payment determination.

* * * * *

(Editor's Note: Sections 75.71 and 75.72 are new and printed in regular type to enhance readability.)

§ 75.71. Quarterly adjustment of nonsolar Tier I obligation.

(a) The Tier I nonsolar photovoltaic obligation of EDCs and EGSs shall be adjusted quarterly during the reporting period to comply with section 2814(c) of the act (relating to additional alternative energy sources).

(b) The quarterly requirement will be determined as follows:

(1) The nonsolar photovoltaic Tier I quarterly percentage increase equals the ratio of the available new Tier I MWh generation to total quarterly EDC and EGS MWh retail sales (new Tier I MWh generation/EDC and EGS MWh retail sales = nonsolar pv Tier I % increase).

(2) The new quarterly nonsolar photovoltaic Tier I requirement equals the sum of the new nonsolar photovoltaic Tier I percentage increase and the annual nonsolar photovoltaic Tier I percentage requirement in § 75.61(b) (relating to EDC and EGS obligations) (nonsolar photovoltaic Tier I % increase + annual nonsolar photovoltaic Tier I % = new quarterly nonsolar photovoltaic Tier I % requirement).

(3) An EDC's or EGS's quarterly MWh retail sales multiplied by the new quarterly nonsolar photovoltaic Tier I requirement (EDC and EGS quarterly MWh x new quarterly nonsolar photovoltaic Tier I % = EDCs' and EGSs' quarterly nonsolar photovoltaic Tier I requirement) yields the quantity of alternative energy credits required by that EDC or EGS for compliance. The EDC and EGS final total annual compliance obligations shall be determined by the program administrator at the end of the compliance year in accordance with § 75.64(c) (relating to alternative energy credit program administrator).

(c) Alternative energy systems qualified consistent with section 2814(a) and (b) of the act shall grant the program administrator access to their credit registry account information as a condition of certification of any alternative energy credits created under these sections.

§ 75.72. Reporting requirements for quarterly adjustment of nonsolar Tier I obligation.

(a) For purposes of implementing § 75.71 (relating to quarterly adjustment of nonsolar Tier I obligation) EDCs and EGSs shall report their monthly retail sales on a quarterly basis during the reporting period. An EDC shall submit its monthly sales data and the monthly sales data

for each EGS serving in its service territory to the program administrator each quarter as follows:

(1) First quarter (June, July and August) due by October 30.

(2) Second quarter (September, October and November) due by January 30.

(3) Third quarter (December, January and February) due by April 30.

(4) Fourth quarter (March, April and May) due by June 30.

(b) Each EGS shall verify its monthly sales data each quarter as follows:

(1) First quarter (June, July and August) due by the second business day after October 30.

(2) Second quarter (September, October and November) due by the second business day after January 30.

(3) Third quarter (December, January and February) due by the second business day after April 30.

(4) Fourth quarter (March, April and May) due by the second business day after June 30.

(c) For purposes of implementing the § 75.71, all Tier I alternative energy systems qualified under section

2814(a) and (b) of the act (relating to additional alternative energy sources) shall provide the following information on a monthly basis:

(1) The facility's total generation from qualifying alternative energy sources for the month in MWh, broken down by source.

(2) The amount of alternative energy credits sold in the month to each EDC and EGS with a compliance obligation under the act.

(3) The amount of alternative energy credits sold in the month to any other entity, including EDCs, EGSs and other users for compliance with another state's alternative/renewable energy portfolio standard or sold on the voluntary market. Each alternative energy credit and the entity they were transferred to must be listed.

(4) The amount of alternative energy credits created and eligible for sale during the month but not yet sold.

(5) The sale or other disposition of alternative energy credits created in prior months and transferred in the month, itemized by compliance status (Pennsylvania portfolio standard, other state compliance, voluntary market, and the like).

[Pa.B. Doc. No. 14-1389. Filed for public inspection July 3, 2014, 9:00 a.m.]