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PA PUBLIC UTILITY COMMISSION
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May 29, 2015

VIA FedEx

Rosemary Chiavetta, Secretary
Pennsylvania Public Utility Commission
Commonwealth Keystone Building
400 North Street
P.O. Box 3265
Harrisburg, PA 17105-3265

Re: Implementation of the Alternative Energy Portfolio Standards Act of 2004
Docket No. L-2014-2404361

Dear Secretary Chiavetta:

Enclosed please find the **Comments of PECO Energy Company** in the above-referenced docket.

Please do not hesitate to contact me if you have any questions at 215-841-4220.

Very truly yours,

Michael S. Swerling

Enclosure

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PA PUBLIC UTILITY COMMISSION
SECRETARY'S BUREAU

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

IMPLEMENTATION OF THE ALTERNATIVE ENERGY PORTFOLIO STANDARDS ACT OF 2004	:	**DOCKET NO. L-2014-2404361**

COMMENTS OF PECO ENERGY COMPANY
TO THE ADVANCE NOTICE OF FINAL RULEMAKING ORDER

Pursuant to the Advance Notice of Final Rulemaking Order ("ANOFR") entered in the above-captioned docket on April 23, 2015, PECO Energy Company ("PECO" or the "Company") hereby submits its comments to the proposed amendments to Chapter 75 of the Pennsylvania Public Utility Commission's (the "Commission's") regulations, 52 Pa. Code §§ 75.1 et seq. ("AEPS Regulations"). According to the Commission, the proposals are intended to increase clarity and address changes to the Alternative Energy Portfolio Standards Act ("AEPS Act") resulting from the enactment of Act 35 of 2007 ("Act 35") and Act 129 of 2008 ("Act 129").

I. INTRODUCTION

On February 20, 2014, the Commission issued a Notice of Proposed Rulemaking ("NOPR"). *See Implementation of the Alternative Energy Portfolio Standards Act of 2004*, Docket No. L-2014-2404361 (Order entered on February 20, 2014). The NOPR proposed "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." (NOPR at 1). Comments were due on August, 4, 2014. However, on August 1, 2014 and at the request of the Pennsylvania Department of Agriculture, the Commission issued a Secretarial Letter extending the comment period to September 3, 2014. Comments were received from the Independent Regulatory Review Commission ("IRRC") and many other interested parties. In its comments, IRRC suggested that the Commission issue an advanced notice of final rulemaking "to engage the regulated community in meaningful dialogue as it develops the final-form rulemaking." (IRRC Comments at 4.) Accordingly, on April 23, 2015, the Commission issued this ANOFR, which proposes to further revise the AEPS Regulations based on the comments received to the February 20, 2014 NOPR.

PECO appreciates the opportunity to comment on the ANOFR and commends the Commission on its efforts to improve the clarity of the AEPS Regulations and ensure their consistency with Act 35 and Act 129.[1] The ANOFR demonstrates the Commission's continued commitment to implementing alternative energy policy through inclusive processes that build on lessons learned in Pennsylvania and other jurisdictions. PECO strongly supports the majority of the Commission's proposed net metering improvements, such as ensuring that: 1) the net metering planning year, contained in the definition of year and yearly, matches the PJM year (June 1 through May 31); and 2) the provisions (contained in Section 75.14) regarding virtual meter aggregation are clear. However, the Company is concerned with the proposal to raise the *110 percent system sizing/output limitation (originally proposed in the NOPR) to 200 percent.* (ANOFR at 11).

[1] For the convenience of the Commission, PECO has attached a "blackline" showing its specific suggested revisions to the Commission's proposed amendments. *See* Appendix A.

II. COMMENTS ON THE PROPOSED RULEMAKING ORDER AND PROPOSED REGULATIONS

A. § 75.1 Definitions

1. Alternative Energy Sources – Distributed Generation Systems

The ANOFR proposes to revise the portion of the definition for alternative energy sources that refers to distributed generation systems to indicate that they may have a nameplate capacity that is not greater than 5 MW. PECO believes that this designation will lead to confusion over the allowable nameplate capacities for distributed generation systems as set forth in the definition for customer-generator contained in 52 Pa.Code § 75.1, which states:

> Customer-generator—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***.

According to the proposed language, customers may mistakenly believe that it is acceptable to interconnect a distributed generation system between 3 and 5 MW without having to comply with the requirements and specifications emphasized above. To avoid such misunderstandings, PECO recommends that the Commission revise the proposed regulations to clarify that systems with nameplate capacities between 3 and 5 MW are only allowable if they comply with the requirements set forth in the definition of customer-generator.

2. **Utility**

The Commission proposed to exclude from the definition of utility an owner or operator of a renewable system that produces no more than 200% of the customer-generator's annual electric usage. Although PECO agrees that owner-operators should be excluded from the definition of utility, the system size limitation should not be more than 110% of the customer-generator's annual electric consumption. For the reasons set forth below, PECO proposes that the Commission establish a 110% size limitation for this exception to the definition of utility.

B. Net Metering

1. System Size Limitations; 110% v. 200%

The ANOFR proposed revisions to Chapter 75, which address concerns raised by IRRC and other commenters regarding the 110% system size limit (originally proposed in the February 20 NOPR) and how it affects new alternative energy sources, existing customer-generators and Anaerobic Digester ("AD") technologies. To address these concerns, the ANOFR proposed a few instances in which modifications to the limitation may be warranted. Specifically, the ANOFR proposed to: 1) increase the system size limit for new systems to 200%; 2) create an exception to this size limit for existing customer-generators and those currently under development; and 3) create another exception to the system size limitation for AD technologies. (IRRC Comments at 6.)

a.) *<u>The 110% Rule is Fundamentally Sound for New Alternative Energy Systems</u>*

First and foremost, PECO believes that the originally proposed 110% rule is fundamentally sound for new alternative energy systems because it is consistent with the intent of the AEPS Act, which defines net metering as a means to primarily offset part or all of the customer-generator's requirements for electricity. It also allows customer-generators to reasonably match generation to load, account for reasonable variances in annual consumption due to operational limitations and control subsidization applicable to non-net metering customers. As a result, the potential for merchant generators to use net-metering to "gain excessive retail rate subsidies" at the expense of other retail rate customers will be greatly reduced. (NOPR at 12.)

The 110% rule also provides more reasonable protections to customers. The 110% rule guarantees protections that the 200% rule cannot, such as prevention of system oversizing, avoidance of merchant generators posing as customer generators, establishment of clear jurisdictional boundaries between FERC and the Commission, and containment of cost shifting.

Conversely, the newly proposed 200% rule is not consistent with the intent of the AEPS Act. Instead, it would facilitate and promote the generation of more electricity than the customer requires. As such, merchant generators would be allowed to use net-metering to gain more excessive retail rate subsidies by almost doubling the expense that would be passed on to other retail rate customers.

PECO also notes that in its comments to the NOPR, it provided the following 7 examples of states with aggressive renewable goals that have either proposed or adopted generation limitations (at the distribution level) to appropriately differentiate true customer-generators from merchant generation facilities, while at the same time balancing the interests of customer-generators and non-customer-generators.

State	System Limit
Maryland	200% of customer's base line annual electricity use
Delaware	110% of customer's aggregated annual electricity consumption
Nevada	The lesser of 1MW or 100% of the customer's annual requirements for electricity
California	Intended primarily to offset part or all of the customer's own electrical requirements. Systems that are sized larger than the customer's electrical requirements would not be eligible for NEM
Arizona	125% of customer's total connected load
Massachusetts	Proposed - No larger than 100% of expected future load
Colorado	120% of annual consumption

Only one state (Maryland) uses a 200% rule. It is the only outlier at the high end of the scale and therefore not consistent with the limitations established in other states. The other states use a percentage limit much closer to the 110% rule. Speaking in terms of averages, the average system size limit for the states in the table above including Maryland is 125%. The average system size limit for the states in the table above excluding Maryland is 110%. Maryland's 200% limit skews the average higher and as such is inconsistent with all other states that appropriately have set their limits at/near the 110% mark. Therefore, on average, the appropriate system size limit should exclude the 200% outlier and be set at 110%. Accordingly, PECO recommends that the Commission adopt a 110% rule.

b.) *<u>The Proposed Exception to the System Size Limit for Existing Alternative Energy Systems and Systems Under Construction is Reasonable</u>*

The ANOFR carved out an exception to the system size limitation for existing systems and those currently under development. The Commission proposed to grandfather systems under development as long as an interconnection application is submitted within 180 days of the effective date of the final regulations adopted in this proceeding. (ANOFR at 12.) PECO believes that the proposed exception is reasonable and should be adopted.

3) *<u>The Commission Should Consider Establishing a Working Group to Explore alternative limits for Digesters that more accurately reflect actual energy production.</u>*

In its comments to the February 20, 2014 NOPR, the DEP indicated that a 110 percent system size limitation may hinder the advancement of Anaerobic Digester ("AD") technologies for Pennsylvania farms. (DEP Comments at 1). These technologies are an essential component of Pennsylvania's plan to restore the Chesapeake Bay because they allow local farms to convert animal manure into energy. (Id.) To remedy this concern, the DEP proposed three options: 1) an exemption to the proposed limits for AD farm technologies; 2) alternative limits that more accurately reflect actual energy production by farms with digesters; or 3) adoption of variable caps for different sources of on-farm alternative energy production. (DEP Comments at 2).

In response, the ANOFR proposed an exemption to the size limitation for alternative energy systems confirmed by the DEP as being used to comply with the Chesapeake Watershed Implementation Plan or that serve as an integral element for compliance with the Nutrient Management Act. (ANOFR at 12-13.) PECO agrees that the proposed regulations should not hinder the use of AD technologies to advance the Chesapeake Bay restoration plan.

However, before adopting a complete exemption for AD technologies, PECO believes that the Commission should consider exploring DEP's proposal to implement alternative limits that more accurately reflect actual energy production by farms with digesters. Accordingly, PECO requests that the Commission consider establishing a working group to explore the possibility of adopting alternative limits for AD technologies.

2. Annual Consumption Determinations for existing and new systems

a) *For existing service locations, the customer's annual consumption should be based on a 12 month period that occurs within 24 months before submission of the interconnection request.*

For existing service locations, the ANOFR allows customers to use electric usage data from any consecutive 12 month period occurring within 60 months prior to submission of the interconnection request (as the basis for sizing the system). (ANOFR at 12). Such an approach allows customers to "cherry pick" the most advantageous 12-months during the 5-year period. PECO is concerned that the proposed 60 month period may be excessive because it could allow customers to set their system sizes with outdated information. PECO believes that recent usage data is more likely to be representative of what a customer's projected usage will be rather than relying upon dated information; since a customer's equipment may have been recently upgraded (e.g. the customer adopted energy efficient measures in year five). Therefore, PECO recommends an approach which strikes an appropriate balance, such as using a consecutive 12 month period that occurs within the 24 months before the interconnection request is filed. .

b) *For new service locations, the annual consumption estimate should be different for residential and commercial/industrial customers.*

For new service locations, the ANOFR allows customers to use an annual electric consumption estimate based on building type, size and anticipated usage or electric equipment and fixtures planned for the new service location (as the basis for sizing the system). PECO believes that this criterion should apply to consumption estimates for commercial/industrial customers based on the high degree of variability in the way businesses operate and use energy.

However, for residential customers, PECO believes there is less variability and as such the annual consumption estimate should be based on the size (square footage) and heating source of the property. Therefore, PECO recommends that the proposed regulation be revised to specify that: 1) the consumption estimate for commercial/industrial customers will be based on building type, size and anticipated usage or electric equipment and fixtures planned for the new service location; and 2) the consumption estimate for residential customers will be based on the size (in terms of the square footage of a heated or cooled space) and the primary heating source of the property. Furthermore, PECO recommends that the Commission establish estimating units, such as kWh per square foot, based on the type of heating source in order to estimate the annual usage for purposes of setting the appropriate system size limit.

C. Process for Obtaining Commission Approval of Customer-Generator Status

1. *The Commission should adopt a 70 day timeframe for processing net metering interconnection applications.*

In the February 20, 2014 NOPR, the Commission proposed a process for EDCs to seek Commission approval of renewable systems with a nameplate capacity of 500 kW or greater. (ANOFR at 15). That proposal included a schedule that could extend out as far as 70 days for processing the application to completion. The timeframe provided 20 days for EDCs to submit an application to TUS with a recommendation, 20 days for the applicant to respond (if the EDC recommended rejecting the application), and 30 days for TUS to issue a decision. (ANOFR at 15-16).

Based on comments received from IRRC, the Commission now proposes to shorten the length of time it can take to process an application. Although PECO supports the Commission's efforts to streamline the process, the Company is concerned that safety and reliability could be jeopardized if the process is hurried.

In PECO's experience, the larger the project, the more complicated it becomes. Large and complex net metering projects require thorough reviews and analyses to determine all possible impacts to the safety and integrity of the distribution system and the interconnected customer. Specifically, if the Commission ultimately adopts a 200% size limitation additional larger distributed generation systems are anticipated, which take longer to evaluate. Reducing the application review period by a month (as the ANOFR proposes) will significantly reduce the amount of time that EDCs and the Commission can dedicate to ensuring system safety and reliability. As such, PECO recommends that the Commission adopt the originally proposed 70 day timeframe when EDC's recommend that the application be denied and a 50 day timeline when EDC's recommend that the application be approved.

D. Interconnection Provisions

1. *The Interconnection Provisions should be revised to clarify that qualifying facilities shall have an electric nameplate capacity that complies with the definition of customer-generator.*

Various provisions in Subchapter C. Interconnection Provisions have been revised to indicate that qualifying facilities may be equal to or less than 5 MW. PECO believes that this designation will lead to confusion over the allowable nameplate capacities for commercial customers as set forth in the definition for customer-generator contained in 52 Pa.Code § 75.1, which states:

> Customer-generator—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.

According to the proposed language, applicants may mistakenly believe that it is acceptable to interconnect a system between 3 and 5 MW without having to comply with the requirements and specifications emphasized above. To avoid such misunderstandings, PECO recommends that the Commission revise the proposed regulations to clarify that systems with nameplate capacities between 3 and 5 MW are only allowable if they comply with the requirements set forth in the definition of customer-generator.

E. AEPS Requirements

1. *Retiring Alternative Energy Credits For Non-Compliant Alternative Energy Systems*

The Company appreciates the Commission's desire to clarify the authority of the program administrator with respect to non-compliant alternative energy systems. *See* 52 Pa.Code § 75.64. However, PECO has significant concerns regarding the Commission's proposal to authorize retirement of past or current alternative energy credits ("AECs") which are deemed to have been generated from non-compliant systems after they have been qualified. If the AECs at issue have already been qualified and transferred to a third party, the unexpected retirement of those AECs would not only punish the non-compliant system but also the current owner of the AECs. If an EDC or EGS is holding AECs that are unexpectedly retired, for example, they would incur additional costs to replace those AECs (which will ultimately be borne by customers) and may be subject to additional AEPS penalties since the compliance of that EDC or EGS with various AEPS obligations could be jeopardized. In addition, if AECs that have already been transferred to a third party are "at risk" for unexpected retirement, PECO expects that the market price of AECs would increase to cover this risk.

PECO believes that the simplest solution would be to provide that the program administrator has authority to take action only with respect to AECs that have not been sold or otherwise transferred to a third party. The administrator would still be able to address non-compliance by suspending or revoking system status and withholding or retiring AECs that are still owned by the owner of the non-compliant system. The Commission could also use its general penalty authority (under 66 Pa. C.S. § 3301) to fashion other appropriate sanctions to penalize a non-compliant system owner for prior sales or transfers of non-compliant AECs.

Additionally, PECO should be allowed to recover the costs associated with procuring the non-conforming AECs as well as the costs associated with procuring replacement AECs. However, to the extent that the Company is able to seek reimbursement from the non-compliant system operator(s), it should be credited against the amount PECO seeks to recover.

2. *Initial Compliance Assessment During True Up Period*

Under the proposed § 75.64(c), the AEPS program administrator would notify EDCs and EGSs of their compliance obligations within 45 days of the end of the reporting period and verify compliance at the end of the 90-day true up period. PECO recommends that an initial compliance assessment by the program administrator between day 46 and day 75 of the true up period be added to the current assessment process. This initial assessment would alert EDCs and EGSs of any impending AEC shortfall and also offer an opportunity for EDCs and EGSs to adjust their retirement portfolios in the last 15 days of the true up period to reduce the risk of an alternative compliance payment. The Company notes that this initial assessment would formalize an information exchange that is already occurring between the program administrator and EDCs and EGSs regarding their compliance obligations.

3. *Approval Process For Alternative Energy Systems Of 500 kW Or Greater*

Under the current AEPS Regulations, an EDC has 10 business days after the receipt of an interconnection request from a system that is 2 MW or less to determine whether its application is complete. Once the request is deemed complete, the EDC has an additional 20 business days to complete its evaluation. *See* 52 Pa. Code § 75.38(c). Under the Commission's proposed §75.17(b), for systems that are 500 kW or more, an EDC would have to submit a recommendation to the Commission's Bureau of Technical Utility Services ("TUS") within 20 days of receiving a completed application.

PECO believes that §75.17(b) should be revised so that it provides an adequate review timeframe, consistent with the existing process. In particular, EDCs should be given 10 *business days* to determine whether an application is complete and then 20 *business days* to evaluate the completed application and communicate that evaluation to TUS. As reflected in PECO's proposed revision to this section, provision of additional information to complete an application would not restart the initial 10-day period but would only extend that period to the extent necessary for an EDC to evaluate the additional information for completeness.

4. *Cost Recovery*

Some of the changes in the Proposed Rulemaking Order may cause PECO to incur additional costs. EDCs should be permitted to recover all reasonable costs incurred to implement the final changes to the AEPS Regulations on a full and current basis.

CONCLUSION

PECO appreciates the opportunity to comment on the Advanced Notice of Final Rulemaking Order and asks that the Commission consider the foregoing recommendations. PECO looks forward to working with the Commission and other stakeholders as the implementation of the AEPS Act progresses.

Respectfully submitted,

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Date: May 29, 2015

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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 **AS AMENDED BY 66 PA. C.S. § 2814**).

***Aggregator*—A person or entity that maintains a contract with ~~an~~** MULTIPLE **individual alternative energy system ~~owner~~**OWNERS **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)__ **WAS COMPLETED AFTER THE EFFECTIVE DATE OF THE ALTERNATIVE ENERGY PORTFOLIO STANDARDS ACT.**

(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 that is established in accordance with the allowable specifications set forth in the definition of customer-generator**__~~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—

*   *   *   *   *

(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:**~~**AN EMERGENCY CONDITION AS DEFINED IN THE PJM INTERCONNECTION, LLC, OPEN ACCESS TRANSMISSION TARIFF OR SUCCESSOR DOCUMENT.**

~~**(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 kWs.

***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—7671q) 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.

* * * * *

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. AN OWNER OR OPERATOR OF AN ALTERNATIVE ENERGY SYSTEM THAT IS DESIGNED TO PRODUCE NO MORE THAN ~~200~~110% OF A CUSTOMER-GENERATOR'S ANNUAL ELECTRIC CONSUMPTION SHALL BE EXEMPT FROM THE DEFINITION OF A UTILITY IN THIS CHAPTER.**

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 EDC SERVICE LOCATION ACCOUNTS, HELD BY THE SAME INDIVIDUAL OR LEGAL ENTITY, 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~~JUNE 1 through ~~April~~MAY ~~30~~31.**

§ 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%~~~~200~~110% of the customer-generator's annual electric consumption at the interconnection meter location when combined with all qualifying virtual meter aggregation locations AS OF THE DATE OF THE INTERCONNECTION APPLICATION.

(I) FOR EXISTING SERVICE LOCATION ACCOUNTS, ANNUAL ELECTRIC *CONSUMPTION SHALL BE BASED ON ELECTRIC USAGE DATA FROM ANY 12* CONSECUTIVE MONTH PERIOD OCCURRING WITHIN ~~60~~24 MONTHS PRIOR TO SUBMISSION OF THE CUSTOMER-GENERATOR'S INTERCONNECTION REQUEST.

(II) FOR NEW COMMERCIAL AND INDUSTRIAL SERVICE LOCATION ACCOUNTS, THE ANNUAL ELECTRIC CONSUMPTION SHALL BE BASED ON THE BUILDING TYPE, SIZE AND ANTICIPATED USAGE OF ELECTRIC EQUIPMENT AND FIXTURES PLANNED FOR THE NEW SERVICE LOCATION. FOR NEW RESIDENTIAL SERVICE LOCATION ACCOUNTS, THE ANNUAL ELECTRIC CONSUMPTION SHALL BE BASED ON SIZE (KWH PER SQUARE FOOT) AND THE TYPE OF HEATING SOURCE FOR THE NEW SERVICE LOCATION.

(III) THE ~~200~~110% OF THE CUSTOMER-GENERATOR'S ANNUAL ELECTRIC CONSUMPTION LIMITATION APPLIES TO ANY INTERCONNECTION APPLICATION FOR A NEW ALTERNATIVE ENERGY SYSTEM OR EXPANSION OF AN EXISTING ALTERNATIVE ENERGY SYSTEM SUBMITTED ON OR AFTER _________. (*Editor's note*: The blank refers to 180 days after the effective date of adoption of this proposed rulemaking.)

(IV) ~~THE 200% OF THE CUSTOMER-GENERATOR'S ANNUAL ELECTRIC CONSUMPTION LIMITATION MAY NOT APPLY TO ALTERNATIVE ENERGY SYSTEMS WHEN THE DEPARTMENT PROVIDES CONFIRMATION TO THE COMMISSION THAT A CUSTOMER-GENERATOR'S ALTERNATIVE ENERGY SYSTEM IS USED TO COMPLY WITH THE DEPARTMENT'S PENNSYLVANIA CHESAPEAKE WATERSHED IMPLEMENTATION PLAN IN COMPLIANCE WITH~~

~~SECTION 303 OF THE FEDERAL CLEAN WATER ACT AT 33 USC § 1313 OR IS AN INTEGRAL ELEMENT FOR COMPLIANCE WITH THE NUTRIENT MANAGEMENT ACT AT 3 PA. C.S. §§ 501, *ET SEQ*.~~

(4) The alternative energy system must have a nameplate capacity ~~of not greater than 50 kW if installed at a residential service location.~~that is established in accordance with the allowable specifications set forth in the definition of customer-generator

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

~~(6)~~**5)** ~~The~~THE **alternative energy system** ~~must have~~HAS **a nameplate capacity that is established in accordance with the allowable specifications set forth in the definition of customer-generator**~~not larger than 5 MW~~ **and meets the conditions in § 75.16 (relating to large customer-generators).**

~~(7)~~**(6) An alternative energy system with a nameplate capacity of 500 kW or more must have Commission approval** ~~for~~TO **net** ~~metering~~METER **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~~**DSP'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)] <u>(k)</u> An EDC **<u>or DSP</u>** 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**<u>, or is specifically authorized under this chapter or by order of the Commission</u>**. The EDC **<u>and DSP</u>** 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)] <u>(l)</u> 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]** **<u>the same</u>** 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 **<u>by the same customer-generator</u>** within 2 miles of the boundaries of the customer-generator's property and within a single EDC's service territory. **<u>All</u> ~~properties~~SERVICE LOCATIONS<u> to be aggregated must be</u> EDC SERVICE LOCATION ACCOUNTS HELD BY THE SAME INDIVIDUAL OR LEGAL ENTITY<u> receiving</u> RETAIL<u> electric</u> ~~generation~~ <u>service</u> FROM THE SAME EDC<u> and have measureable load independent of any alternative energy system.</u>** 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.

* * * * *

<u>§ 75.15. [RESERVED]</u>

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<u>§ 75.16. Large customer-generators.</u>

<u>(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.</u>

<u>(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:</u>

(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 **RTO** tariff or agreement.

~~(3)~~**(2)** 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 ~~2015~~**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 REJECT AN APPLICATION** to the Bureau of Technical Utility Services.

(d) The Bureau of Technical Utility Services will review the net metering application, the EDC recommendation and **APPLICANT** 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~~**10** days of **A** submission **RECOMMENDING APPROVAL** or 30 days of **a submission recommending denial** and describe in detail the reasons for approval or disapproval. ~~**THE BUREAU OF TECHNICAL UTILITY SERVICES WILL APPROVE OR DISAPPROVE A NET METERING APPLICATION WITHIN 5 DAYS OF AN APPLICANT'S RESPONSE TO AN EDC'S RECOMMENDATION TO DENY APPROVAL, BUT NO MORE THAN 30 DAYS AFTER AN EDC SUBMITS AN**~~

~~**APPLICATION WITH A RECOMMENDATION TO DENY APPROVAL, WHICHEVER IS EARLIER.**~~ 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~~ shall established in accordance with the allowable specifications set forth in the definition of customer-generator~~[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 shall be established in accordance with the allowable specifications set forth in the definition of customer-generator~~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 that is ~~of [2] 5 MW or less~~established in accordance with the allowable specifications set forth in the definition of customer-generator and 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 has been established in accordance with the allowable specifications set forth in the definition of customer-generator~~is [2] 5 MW or less~~.

(2) The small generator facility ~~is less than [2] 5 MW~~has an electric nameplate capacity that has been established in accordance with the allowable specifications set forth in the definition of customer-generator and is not certified.

(3) The small generator facility has an electric nameplate capacity that has been established in accordance with the allowable specifications set forth in the definition of customer-generator ~~is less than [2] 5 MW~~ and is 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 that has been established in accordance with the allowable specifications set forth in the definition of customer-generator~~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, have been established in accordance with the allowable specifications set forth in the definition of customer-generator~~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, if such alternative energy credits have not already been transferred to a third party by the owner of the 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) **After day 45 but before day 76 of the true up period, the program administrator *shall provide an initial compliance assessment for all EDCs and EGSs for informational purposes.*** At the end of each true-up period, the administrator shall verify **final** 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.

*　　*　　*　　*　　*

§ 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 non- solar 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).

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3. Place label in shipping pouch and affix it to your shipment so that the barcode portion of the label can be read and scanned.

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Use of this system constitutes your agreement to the service conditions in the current FedEx Service Guide, available on fedex.com.FedEx will not be responsible for any claim in excess of $100 per package, whether the result of loss, damage, delay, non-delivery,misdelivery,or misinformation, unless you declare a higher value, pay an additional charge, document your actual loss and file a timely claim.Limitations found in the current FedEx Service Guide apply. Your right to recover from FedEx for any loss, including intrinsic value of the package, loss of sales, income interest, profit, attorney's fees, costs, and other forms of damage whether direct, incidental,consequential, or special is limited to the greater of $100 or the authorized declared value. Recovery cannot exceed actual documented loss.Maximum for items of extraordinary value is $1,000, e.g. jewelry, precious metals, negotiable instruments and other items listed in our ServiceGuide. Written claims must be filed within strict time limits, see current FedEx Service Guide.