Regulatory Analysis Form

(Completed by Promulgating Agency)

(All Comments submitted on this regulation will appear on IRRC's website)

INDEPENDENT REGULATORY REVIEW COMMISSION

(1) Agency
Public Utility Commission ("PUC")

(2) Agency Number: L-2014-2404361

Identification Number: 57-304

IRRC Number: **3061**

(3) PA Code Cite: 52 Pa. Code §§ 75.1, 75.12, 75.13, 75.14, 75.16, 75.17, 75.22, 75.31, 75.34, 75.39, 75.40, 75.51, 75.61, 75.62, 75.63, 75.64, 75.65, 75.71, and 75.72.

(4) Short Title: Implementation of the Alternative Energy Portfolio Standards Act of 2004

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(6) Type of Rulemaking (check applicable box):

- ☐ Proposed Regulation
- ☒ Final Regulation
- ☐ Final Omitted Regulation
- ☐ Emergency Certification Regulation;
  - ☐ Certification by the Governor
  - ☐ Certification by the Attorney General

(7) Briefly explain the regulation in clear and nontechnical language. (100 words or less)

Under its statutory duty to implement and enforce the Alternative Energy Portfolio Standards Act (AEPS Act or Act), 73 P.S. §§ 1648.1-1648.8 and 66 Pa. C.S. § 2814, as well as its statutory duty to ensure default customer service rates at the least cost to customers over time and that rates are just and reasonable under the Pennsylvania Public Utility Code (Public Utility Code), 66 Pa. C.S. §§ 1301, 2807(e), the Pennsylvania Public Utility Commission has revised its regulations pertaining to net metering, interconnection, and portfolio standard compliance provisions of the Act to comply with the Act 35 of 2007 and Act 129 of 2008 amendments to the AEPS Act and to clarify certain issues of law, administrative procedure, and policy.

(8) State the statutory authority for the regulation. Include specific statutory citation.

1 Pa. C.S. § 1932; 66 Pa. C.S. §§ 501, 504-506, 523, 1301, 1501, 1504, 2807(e), 2814; 45 P.S. §§ 1201-1202; 1 Pa. Code §§ 7.1, 7.2, and 7.5; The Commonwealth Attorneys Act, 71 P.S. § 732-204(b); The Regulatory Review Act, 71 P.S. § 745.5; The Administrative Code, 71 P.S. § 232; The Alternative Energy Portfolio Standards Act of 2004, 73 P.S. §§ 1648.5 and 1648.7(a)-(b), 25 Pa. Code §§ 75.1 *et seq.*; and Act 129 of 2008, 66 Pa. C.S. § 2814.

(9) Is the regulation mandated by any federal or state law or court order, or federal regulation? Are there any relevant state or federal court decisions? If yes, cite the specific law, case or regulation as well as, any deadlines for action.

The proposed regulation changes are not mandated by federal law, federal regulation, or court order. However, the Pennsylvania state statute, the AEPS Act of 2004, requires the PUC to develop technical and net metering interconnection rules for customer-generators, 73 P.S. § 1648.5, and to implement and enforce the AEPS Act, 73 P.S. § 1648.7(a)-(b). In addition, the Act 129 of 2008 amendments to the Public Utility Code require that all energy purchased to provide default service to customers ensures adequate and reliable service at the least cost to customers over time, including energy required to be purchased under the AEPS Act. *See* 66 Pa. C.S. § 2807(e). Accordingly, the PUC has amended the regulations pertaining to the net metering, interconnection, and portfolio standard compliance provisions of the AEPS Act to comply with the Act 35 of 2007 and Act 129 of 2008 amendments to the AEPS Act and Public Utility Code and to clarify certain issues of law, administrative procedure, and policy.

(10) State why the regulation is needed. Explain the compelling public interest that justifies the regulation. Describe who will benefit from the regulation. Quantify the benefits as completely as possible and approximate the number of people who will benefit.

As discussed above, these regulation changes are needed and adopted pursuant to state law in order to comply with the AEPS Act, the Act 35 of 2007 and Act 129 of 2008 amendments to the AEPS Act and Public Utility Code to clarify certain issues of law, administrative procedure, and policy.

All stakeholders and interested parties, including electric distribution companies (EDCs), electric generation suppliers (EGSs), alternative energy system developers, customer-generators seeking net metering and all EDC ratepayers, will benefit from these regulations, which clarify issues of law, administrative procedure, and policy by reducing uncertainty regarding which generation resources qualify for alternative energy system status, interconnection and net metering. In particular, the approximately one-hundred alternative energy system development companies and installation companies will benefit from these clarifications, as it should reduce the time and money spent on developing, installing and qualifying alternative energy systems. It should also reduce or even eliminate the time and money spent by these companies in the past on investigating and beginning initial development of systems that they later learn will not qualify.

These regulation changes will also balance the benefits provided to developers, owners of alternative energy systems, and net metering customer-generators with the costs borne by EDCs, EGSs and electric utility ratepayers to meet the requirements of the AEPS Act in a cost-effective manner. These proposed changes will benefit the millions of EDC ratepayers and EGS customers. The Commission, in its 2014 AEPS Act Annual Report, is projecting that it could cost over $164 million to comply with the AEPS Act's 18% of retail sales requirements. The 2014 Annual report is available at: http://www.puc.pa.gov/Electric/pdf/AEPS/AEPS_Ann_Rpt_2014.pdf. The above-market net metering costs that are also borne by the ratepayers will be in addition to those costs. Therefore, based on these magnitudes, it is imperative that this program be implemented in a cost-effective manner.

Finally, the rules will reasonably limit the amount of energy default service providers purchase at above market retail rates, ensuring that default service is provided at the least cost to customers over time, as required by the Act 129 of 2008 amendments to the Public Utility Code. 66 Pa. C.S. 2807(e). The

purpose of this limitation is to avoid having default service customers pay substantial net metering subsidies to merchant scale alternative energy systems. Accordingly, these regulatory changes will ensure that rates paid by ratepayers are just and reasonable as required by the Public Utility Code. 66 Pa. C.S. § 1301.

Based on information obtained from EDCs, it appears that default rate customers are paying an approximate 40% premium for the excess energy produced by a relatively few oversized customer-generators. For example, in one service territory, a total of over $8.6 million was paid to just 10 large customer-generators for the year ending May 31, 2015, for excess generation at retail rates in excess of 10 cents per kilowatt-hour. The prior year, ending May 31, 2014, a total of over $6.4 million was paid to these same 10 customer-generators for excess generation at retail rates in excess of 10 cents per kilowatt-hour, with some at rates in excess of 11 cents per kilowatt-hour. This compares to an average wholesale price for 2015 of 4.665 cents per kilowatt-hour[1] that would still net these same customer-generators over $3.9 million dollars if they received an avoided cost of wholesale power rate for the same amount of excess generation for 2015. If the magnitude of and number of oversizing is left unchecked, an approximate 40% premium on energy supplied to and paid for by default service customers will increase default service rates unless the reasonable 200% of historical annual load limit is applied to newly installed systems. Again, the purpose here is to balance the availability of net metering subsidies, with the over-arching statutory requirement that default service rates remain just and reasonable. Alternative energy systems that produce over 200% of their historic load are more likely to be in the business of *selling* energy than purchasing energy from the EDC as consumers. We note that the 200% of historical load limit does not apply to the 10 customer-generators used in this example, nor other oversized systems installed prior to the effective date of this provision, which is 180 days after this Final Rulemaking becomes effective.

These large customer-generators are in the same rate class as other small businesses, including farmers, and impact the default service rates these customers pay, unless they obtain their power from an EGS. While customers can shop for lower prices, the reality is that the default service rate in each customer class sets the ceiling for alternative offers by EGSs for customers in that rate class. As the default service rate rises, the rates all shopping customers pay also tends to rise. Therefore, all ratepayers, including shopping customers, will benefit from this reasonable 200% design limit on customer-generators, in that it will not only ensure that the default service rate is just and reasonable and at the least cost to customers over time, it will also ensure that the rates all customers pay are just and reasonable.

We further note that this size limit will have little to no impact on rooftop solar photovoltaic installations (the primary type of alternative energy system installed and employed by residential customers) for residential customers. Again, based on data received from the EDCs as of May 31, 2015, the total number of residential solar photovoltaic customer-generators in the Commonwealth was 8,569. The average size of these residential solar photovoltaic systems ranges from 7.2 kilowatts to 9 kilowatts depending on EDC service territory. The average residential annual load ranged from 8,400 kilowatt-hours to 11,448 kilowatt-hours, again depending on the EDC service territory. Based on this annual load data and a typical annual capacity factor of 14% for solar photovoltaic systems installed in Pennsylvania, a residential customer can install systems ranging in size from 13.7 kilowatts to 18.67 kilowatts and meet the 200% design limit. This demonstrates that residential customer-generators are currently installing systems to meet their annual load and can continue to install such systems of the

[1] Data from SNL Energy subscription service.

same size or up to double the current average size of installation. We also note that the estimated square-footage of a rooftop solar system is approximately one square-foot per 10 watts of capacity.[2] Accordingly, a 7.2 kilowatt system would require 720 square-feet of rooftop. An 18.67 kilowatt system would require 1,867 square-feet of rooftop, which is likely to be far greater than the typical available south facing rooftop available on most residential homes. Thus, the new regulation will not restrict or discourage, in any way, the development of residential rooftop solar photovoltaic systems.

(11) Are there any provisions that are more stringent than federal standards? If yes, identify the specific provisions and the compelling Pennsylvania interest that demands stronger regulations.

These regulations do not contain any provisions that are more stringent than federal standards. Renewable/alternative energy portfolio standards are currently only enacted at the state level.

(12) How does this regulation compare with those of the other states? How will this affect Pennsylvania's ability to compete with other states?

As discussed in the PUC's Final Rulemaking Order of February 11, 2016, Docket No. L-2014-2404361, the regulation's changes regarding net metering are consistent with the regulatory treatment of net metering in other states. The Commission found that net metering size limit is reasonable as it is the same or higher than similar limits imposed by other states in the region. As noted in both the Proposed Rulemaking Order and the Advance Notice of Final Rulemaking Order, the Maryland Public Service Commission limits customer-generators to 200 percent of the customer-generator's baseline annual usage. *See* COMAR 20.50.10.01(D)(1)(b). In addition, Delaware limits customer-generators to no more than 110 percent of the customer's aggregate electric consumption. *See* 26 Del. Admin. Code 3001-8.6.2, Del. Pub. Serv. Comm'n, DE. ADC 26 3000 3001, §8.6.2 (Westlaw) (2014). Additionally, New Jersey requires that the generating capacity cannot exceed the customer's combined metered annual energy usage. *See* N.J. Admin. Code 14:8-4.3(a) (Westlaw) (2014). No commentator has demonstrated that these same or similar limitations imposed in other states have prevented or restricted the development of alternative energy systems in those states. We also note that as these limitations, along with the Commission's policy statement limiting third-party owned and operated systems to 110% of annual load, have been in place for years, some more than a decade, the knowledge and ability of developers to comply with this requirement is well known and established. As such, we find that such a limit is reasonable and will not create an impediment to further development of customer-generator facilities. *See* Final Rulemaking Order at 48.

Each state has its own distinct alternative/renewable energy portfolio standards. Generally speaking, Pennsylvania's standards run the middle of the gamut and are not as stringent as many other states in the northeast and elsewhere that have alternative/renewable energy portfolio standards. Many other states do not have mandatory alternative/renewable energy portfolio standards. The amended regulations under Pennsylvania's AEPS Act should not materially affect Pennsylvania's ability to compete with other states. In fact, the regulations ensure that ratepayers, including small and large businesses in the Commonwealth, pay rates that are just and reasonable and that provide the least cost over time, potentially providing these small and large businesses a competitive advantage over similar businesses in other states.

[2] *See* FAQs | Solar Professional Services, LLC at http://solarproservices.com/index.php/faqs/.

We note that as recently as February 17, 2016, Nevada issued an Order shifting all net metering customer-generators from a retail rate to a cost-based rate for all energy delivered to the grid. This change applies to all net metering customer-generators, regardless of when the systems were installed. The change to cost-based rates is to occur in five increments over 12 years (one step every three years beginning January 1, 2016). See Reconsideration Order at the following link: http://pucweb1.state.nv.us/PDF/AxImages/DOCKETS_2015_THRU_PRESENT/2015-7/9690.pdf. We further note that the amended regulations only apply the 200% limit to new systems or expanding systems installed 180 days after the effective date of these regulations, which is far less restrictive than Nevada's net metering changes.

(13) Will the regulation affect any other regulations of the promulgating agency or other state agencies? If yes, explain and provide specific citations.

Pursuant to the AEPS Act, 73 P.S. § 1648.7, the PUC and the Department of Environmental Protection (DEP) "shall work cooperatively to monitor the performance of all aspects of [the AEPS Act] and provide an annual report to the chairman and minority chairman of the Environmental Resources and Energy Committee of the Senate and the chairman and minority chairman of the Environmental Resources and Energy Committee of the House of Representatives."

These regulations do not effect this cooperation. Under the revised regulations, the Commission, in cooperation with DEP, will continue to provide this annual report. A copy of the latest Annual Report is available at http://www.puc.pa.gov/Electric/pdf/AEPS/AEPS_Ann_Rpt_2014.pdf.

In addition, DEP is to "ensure that all qualified alternative energy sources meet all applicable environmental standards and shall verify that an alternative energy source meets the standards set forth in section 2." *See,* 73 P.S. § 1648.7(b).

These regulation changes will not affect the regulations of DEP or other state agencies. To date, the DEP has not promulgated regulations related to the AEPS Act. Regarding DEP's responsibility to verify that an alternative energy source meets the standards set forth in Section 2 of the AEPS Act, 73 P.S. § 1648.2 (Definitions), the changes to the definitions section of the regulations simply incorporate new definitions contained in the Act 129 of 2008 amendments, 66 Pa. C.S. § 2814, or provide guidance on the meaning of words used throughout the regulations. These regulation definition changes provide clarity and better understanding to all stakeholders and have been developed based on experience with implementing the AEPS Act over the past ten years and input from commentators.

(14) Describe the communications with and solicitation of input from the public, any advisory council/group, small businesses and groups representing small businesses in the development and drafting of the regulation. List the specific persons and/or groups who were involved. ("Small business" is defined in Section 3 of the Regulatory Review Act, Act 76 of 2012.)

During the development and drafting of the regulation changes, the Commission received input from the public, advisory council/groups, small businesses and groups representing small businesses by seeking and receiving comments on the proposed rules following the issuance of the Notice of Proposed Rulemaking Order on February 20, 2014, and the Advance Notice of Final Rulemaking Order on April 23, 2015. In addition, Commission staff met with representatives of the Farm Bureau, DEP, EDCs and solar developers during which these representatives provided input and perspectives on the regulations.

Furthermore, during the over ten years the Commission has been implementing the AEPS Act, there have been innumerable communications and solicitations from the public, small and large alternative energy system developers and installers, customer-generators from all rate classes, small and large businesses that buy and sell alternative energy credits, small and large EGSs and EDCs, as well as groups and associations that represent these various interests including ratepayers. As previously noted, most of the changes to the regulations are intended to clarify certain issues of law, administrative procedure, and policy identified during these innumerable communications and solicitations.

(15) Identify the types and number of persons, businesses, small businesses (as defined in Section 3 of the Regulatory Review Act, Act 76 of 2012) and organizations which will be affected by the regulation. How are they affected?

Eleven EDCs, of which four are considered Pennsylvania based small businesses, will be impacted by the changes. However, the impact should be minimal as most of the changes that impact EDCs simply provide more clarity on what is expected of them or provides clearer administrative processes that match current practices or provides more complete guidance on processes needed to comply with the AEPS Act as amended.

Currently, 106 EGSs, of which twenty-two (22) are considered Pennsylvania based small businesses, will be impacted by the changes. However, the impact to EGSs are minimal in that most of the changes affecting EGSs are mandated by the Act 129 of 2008 amendment to the AEPS Act, 66 Pa. C.S. § 2814, that requires the Commission to adjust the Tier I requirements for EGSs and EDCs on a quarterly basis. The changes also ensure that both EDCs and EGSs that have AEPS Act compliance obligations have accurate and up to date information on the number of credits needed for compliance in a timely manner that will allow them to obtain and retire the requisite number of alternative energy credits by the close of the statutorily set true-up period.

It is estimated that approximately one-hundred alternative energy system development companies and alternative energy system installation companies, most of which are considered Pennsylvania based small businesses, will be impacted by the changes. However, while the changes may impact the size of some of the alternative energy systems these entities develop and install for customer-generators seeking net metering subsidies, it is expected to have minimal impact on the number of systems they develop or install as past experience shows that most customer-generator systems currently being installed already meet the new requirements. Furthermore, the clarifying changes will provide these entities more regulatory certainty as the changes make current practice explicit, where it had previously been implicit in the regulations. The vast majority of customer-generators are residential customers who install rooftop solar photovoltaic systems. The average solar photovoltaic system installed at a residential customer-generator location ranges from 7.2 kW to 9 kW depending on the service territory, which is at least half the size allowed under the new regulations, based on average annual residential customer load and a 14% annual capacity factor for solar photovoltaic systems installed in Pennsylvania.

Currently, there are 90 known active alternative energy credit aggregators, of which 57 are Pennsylvania based small businesses that will be impacted. However, the impacts are minimal and intended to ensure an appropriate level of consumer protection for system owners and other parties who contract with aggregators to buy and sell their alternative energy credits, and to ensure the validity of the credits.

Three facilities that generate electricity in Pennsylvania from pulping processes, of which two are considered Pennsylvania based small businesses, will be impacted by these regulations. However, the changes related to these wood manufacturers are mandated by the Act 129 of 2008 amendments, which primarily benefit these entities by making them Tier I (higher value) resources.

(16) List the persons, groups or entities, including small businesses, that will be required to comply with the regulation. Approximate the number that will be required to comply.

Eleven EDCs, of which four are considered Pennsylvania based small businesses.
Currently, 106 EGSs, of which 22 are considered Pennsylvania based small businesses.
Currently, 90 active alternative energy credit aggregators, of which 57 are considered Pennsylvania based small businesses.
Three facilities that generate electricity in Pennsylvania from pulping processes, of which two are considered Pennsylvania based small businesses.
Future customer-generators and owners of alternative energy systems.

(17) Identify the financial, economic and social impact of the regulation on individuals, small businesses, businesses and labor communities and other public and private organizations. Evaluate the benefits expected as a result of the regulation.

It is possible that there may be a minor increase in the cost of future small solar photovoltaic system installations with a nameplate capacity of 15 kilowatts or less due to the metering requirements. Only a few installations would be affected as all installations of this type use inverters that register the generation output and most, if not all, can install a qualifying meter at minimal cost. The current regulations do not require inverter or meter readings to verify the output of these systems. Under the current regulations, these small systems have been able to use estimates of the system output, provided they meet specific requirements, such as the type of solar photovoltaic panel material and directional orientation. Experience demonstrates that while the new metering requirements on these small systems will increase the costs and administrative burdens on the system owners, those costs are minimal compared to the need for system integrity to ensure that the credits being claimed are valid. In addition, we note that these metering requirements are currently required for all other alternative energy systems and have not proven to be a barrier to development of those systems. Finally, we note that the elimination of the use of estimates for these small systems will result in reduced time spent by the Commission's contracted program administrator to run modeling software to estimate the generation output of these systems. The cost savings associated with this are deemed insignificant but there is greater confidence in the long-term reliability of the claimed alternative energy credits by not relying on estimates of generation. This is consistent with the direction being taken by many other states, including New Jersey. *See e.g.*, N.J. Admin. Code 14:8-2.9(c) (Westlaw) (2014).

(18) Explain how the benefits of the regulation outweigh any cost and adverse effects.

The regulations add clarity to definitions and administrative processes that will reduce uncertainty for all stakeholders. Costs associated with these clarifications and administrative processes should be offset by the benefits of obtaining more certainty as to the benefits available to qualified alternative energy systems, as well as any potential alternative energy system development. This increased certainty should decrease developmental costs associated with the development of alternative energy systems.

As explained in RAF Question 10 above and in the Final Rulemaking Order at pages 45-51, the primary reasons for the 200% design limit on customer-generators is the above-market costs borne by ratepayers, specifically default service customers, and the requirements in the Public Utility Code that such default service rates must be just and reasonable and obtained at the least cost to customers over time. The 200% design limit does not reduce access to compensation for owners of alternative energy systems, just the amount of compensation. All alternative energy systems are free to interconnect and sell their power, regardless of size. For example, the Commission is aware of multiple landfill gas facilities ranging in size from 3 megawatts to 10 megawatts that are interconnected and selling their power and are not customer-generators. As explained in RAF Question 10 above, these large facilities are able to obtain significant compensation from the wholesale market for the energy they produce. Also, as explained in the Final Rulemaking Order:

> While net metering is an avenue to encourage the development of alternative energy systems, as it allows customers to produce on-site generation and recoup the cost of installing and interconnecting such systems, the need for such excessively sized systems to support such development is unnecessary and unfair to ratepayers who would be asked to finance the difference between the retail and wholesale price of the electricity produced by these oversized systems. While it may take several years to recoup the investment in these systems, we note that many of these systems last two or more decades, and no commentator has demonstrated that payments at the retail rate for all excess energy is required for two or more decades to recoup such costs. In particular, we find it significant that these same systems receive tax credits and revenue from the sale of the alternative energy credits generated by these very same systems, in addition to offsetting electric usage charges and the annual payments for the excess generation at the retail rate.

Final Rulemaking Order at 47.

Regarding the "independent load" requirement, as explained in the Final Rulemaking Order at 32-35, this is a statutory requirement. This requirement, however, does not preclude someone from installing and interconnecting an alternative energy system at a location with no independent load and selling the energy it produces to specific customers or to the wholesale market. They simply cannot qualify for net metering subsidies paid for by EDC default service customers. In fact, these alternative energy entrepreneurs can sell their power and receive compensation for that power on a monthly basis, rather than wait till the end of the year to receive the compensation as under the net metering provisions. In the end, as explained in the quote above, net metering is just one avenue to obtain a form of compensation, but not the only form of compensation available to owners of alternative energy systems.

(19) Provide a specific estimate of the costs and/or savings to the **regulated community** associated with compliance, including any legal, accounting or consulting procedures which may be required. Explain how the dollar estimates were derived.

Although a specific cost study was not conducted, any costs related to the additional administrative processes were either mandated by the AEPS Act or the Act 129 of 2008 amendment that required the Commission to adjust the Tier I requirement on a quarterly basis, or will be offset by avoided costs attributable to the increased regulatory certainty.

Furthermore, as explained in RAF Question 10 above, these regulation changes are intended to balance the benefits provided to developers, owners of alternative energy systems, and net metering customer-generators with the above-market energy costs borne by EDCs, EGSs and electric utility

ratepayers to meet the requirements of the AEPS Act in a cost-effective manner. Examples of these costs and benefits are also provided in RAF Question 10.

(20) Provide a specific estimate of the costs and/or savings to the **local governments** associated with compliance, including any legal, accounting or consulting procedures which may be required. Explain how the dollar estimates were derived.

Except to the extent that a local government owns an alternative energy system, in which case it will be treated the same as any other system owner, local governments are not impacted by these regulations as they have no compliance obligations under the AEPS Act and therefore, should incur no costs as a result of these regulations. Local governments may see savings related to default service rates as a result of reduced payouts for excess generation, at above market rates, due to the regulation limiting the size of customer-generator systems to produce no more than 200% of the customer's historical load requirements.

(21) Provide a specific estimate of the costs and/or savings to the **state government** associated with the implementation of the regulation, including any legal, accounting, or consulting procedures which may be required. Explain how the dollar estimates were derived.

Except to the extent that the state government owns an alternative energy system, in which case it will be treated the same as any other system owner, the state government is not impacted by these regulations as it has no compliance obligations under the AEPS Act and therefore, should incur no costs as a result of these regulations. The state government may see savings related to default service rates as a result of reduced payouts for excess generation, at above market rates, due to the regulation limiting the size of customer-generator systems to produce no more than 200% of the customer's historical load requirements.

(22) For each of the groups and entities identified in items (19)-(21) above, submit a statement of legal, accounting or consulting procedures and additional reporting, recordkeeping or other paperwork, including copies of forms or reports, which will be required for implementation of the regulation and an explanation of measures which have been taken to minimize these requirements.

Regarding the requirement at § 75.13(a)(3), customer-generators, the owners, developers or installers of these systems will now have to submit documentation demonstrating that the alternative energy system is designed to provide no more than 200% of the electric customer's historical load requirements or the anticipated load requirement at new service locations. The purpose of this limitation is to avoid having default service customers pay substantial net metering subsidies to merchant scale alternative energy systems. While this is a new requirement under the current regulations, the regulated community has experience with this requirement under the Commission's policy statement for third-party owned and operated systems. In that policy statement, the Commission made it a policy to allow interconnection and net metering of alternative energy systems that are owned and operated by third-parties that place the alternative energy system on the customer's property and sell the power from those systems to the customer, provided the systems were sized to provide no more than 110% of the customer's historical load. *See*, *Net Metering – Use of Third Party Operators*, Final Order at Docket No. M-2011-2249441 (entered March 29, 2012). In addition, as mentioned above, Maryland, Delaware and New Jersey have similar requirements. Based on four years of operating under this policy statement and the experiences

of Maryland, Delaware and New Jersey, we do not believe that this requirement will be burdensome or a barrier to the development of alternative energy systems.

Regarding the requirements at § 75.17 (process for obtaining approval of customer-generator status) EDCs will have to provide applications for net metering to the Commission along with a recommendation as to whether the alternative energy system qualifies for net metering for all applications for net metering of systems with a nameplate capacity of 500 kilowatts or greater. While the submission of this information to the Commission for review is a new requirement, EDCs currently obtain this information and provide feedback to the applicant as to whether a system qualifies for net metering. As the Commission stated in the Final Rulemaking order at 99, "this timeline will not unreasonably delay the employment of an alternative energy system as the timeline is similar to the interconnection timelines and should run concurrently with those timelines. Furthermore, we note that we are not seeking anything in this process that the developer would not already be required to provide the EDC." Therefore, the additional burden of submitting this information to the Commission for review should be minimal and not pose a barrier to the development of qualified alternative energy systems. Furthermore, we note that this step provides the added benefit of increased regulatory certainty for both the applicant and the EDC.

Regarding the requirement at § 75.64(c)(3) that EDCs and EGSs provide pricing information on alternative energy credits used for compliance, this information is needed to calculate the solar alternative compliance payment, which pursuant to the AEPS Act, equals 200% of the average market value of solar renewable energy credits. *See*, 73 P.S. § 1648.3(f)(4). In addition, the credit price information is needed to comply with the requirement to provide a report to the General Assembly that contains the "[c]urrent costs of alternative energy on a per kilowatt hour basis for all alternative energy technology types." See 73 P.S. § 1648.7(c). Furthermore, while this information has been provided in the past, the changes provide clarity on the information to be provided and will ensure consistent reporting by all EDCs and EGSs.

Regarding the reporting requirements in §75.72 (reporting requirements for quarterly adjustment of non-solar Tier I obligation), EDCs and EGSs will be required to report their monthly retail sales data on a quarterly basis, with the EDCs being required to report monthly sales data for its default service and the EGSs serving in the EDC's service territory. This data is required to make the quarterly adjustment to the EDC and EGS Tier I requirements as mandated in the Act 129 of 2008 amendments to the AEPS Act. *See*, 66 Pa. C.S. § 2814(c). In addition, the qualifying hydropower and biomass energy facilities seeking Tier I status will also be required to report their total monthly generation in megawatt-hours, as well as the number of alternative energy credits created, sold to EDCs and EGSs, sold to other entities and unsold credits. Again, this data is required to make the quarterly adjustment to the EDC and EGS Tier I requirements as mandated in the Act 129 of 2008 amendments to the AEPS Act. *See*, 66 Pa. C.S. § 2814(c). We note that since May of 2009, the EDCs, EGSs and qualifying facilities have been providing this information. The changes simply codify and clarify what the Commission previously established by Order. *See, Implementation of Act 129 of 2008 Phase 4 – Relating to the Alternative Energy Portfolio Standards Act*, Final Order at Docket No. M-2009-2093383 (entered May 28, 2009).

(23) In the table below, provide an estimate of the fiscal savings and costs associated with implementation and compliance for the regulated community, local government, and state government for the current year and five subsequent years.

	Current FY Year	FY +1 Year	FY +2 Year	FY +3 Year	FY +4 Year	FY +5 Year
SAVINGS:	$	$	$	$	$	$
Regulated Community	minimal	minimal	minimal	minimal	minimal	minimal
Local Government	minimal	minimal	minimal	minimal	minimal	minimal
State Government	minimal	minimal	minimal	minimal	minimal	minimal
Total Savings	minimal	minimal	minimal	minimal	minimal	minimal
COSTS:						
Regulated Community	minimal	minimal	minimal	minimal	minimal	minimal
Local Government	0	0	0	0	0	0
State Government	minimal	minimal	minimal	minimal	minimal	minimal
Total Costs	minimal	minimal	minimal	minimal	minimal	minimal
REVENUE LOSSES:						
Regulated Community	minimal	minimal	minimal	minimal	minimal	minimal
Local Government	0	0	0	0	0	0
State Government	0	0	0	0	0	0
Total Revenue Losses	minimal	minimal	minimal	minimal	minimal	minimal

(23a) Provide the past three year expenditure history for programs affected by the regulation.

Program	FY -3	FY -2	FY -1	Current FY
EDC reporting requirements for quarterly adjustments for 75.72	Estimated at $17,000	Estimated at $17,000	Estimated at $17,000	Estimated at $17,000
EGS reporting requirements for quarterly adjustments for 75.72	Estimated at $37,000	Estimated at $37,000	Estimated at $37,000	Estimated at $37,000
Generator reporting requirements for quarterly adjustments for 75.72	Estimated at $2,700	Estimated at $2,700	Estimated at $2,700	Estimated at $2,700

(24) For any regulation that may have an adverse impact on small businesses (as defined in Section 3 of the Regulatory Review Act, Act 76 of 2012), provide an economic impact statement that includes the following:

(a) An identification and estimate of the number of small businesses subject to the regulation.
Four EDCs, 22 EGSs, approximately one-hundred alternative energy system development and installation companies, 57 alternative energy credit aggregators, and two facilities that generate electricity in Pennsylvania from pulping processes.

(b) The projected reporting, recordkeeping and other administrative costs required for compliance with the proposed regulation, including the type of professional skills necessary for preparation of the report or record.
The four EDCs are anticipated to have annual reporting, record keeping and other administrative costs of $1,545/EDC to comply with the reporting requirements in § 75.72, which involves tracking and reporting electric sales in their service territory.
The 22 EGSs are anticipated to have annual reporting, record keeping and other administrative costs of $400/EGS to comply with the reporting requirements in § 75.72, which involves tracking and reporting their electric sales in each EDC service territory where they have sales.
The two facilities that generate electricity in Pennsylvania from pulping processes are anticipated to have annual reporting, record keeping and other administrative costs of $900/company to comply with the reporting requirements in § 75.72, which involves tracking and reporting their electric generation.
Alternative energy system developers and installers will have some additional reporting requirements when developing customer-generator installations seeking to net meter. These additional reporting requirements include the customer's historical annual electric usage or anticipated electric usage and the design output of the alternative energy system to demonstrate that the system is not designed to exceed 200% of the customer's historical annual usage. These costs are anticipated to be minimal as the customer can obtain the usage data from the EDC and the developer already needs the design output of the system to ensure a safe and reliable installation. In addition, these developers have been providing the same data to comply with the Commission's Policy Statement on Third-Party Owned and Operated Systems. Finally, operators of systems that seek the Chesapeake Watershed Implementation Plan or Nutrient Management Plan exemption to the 200% design limit only need to provide information that they already have available and provide to DEP.

(c) A statement of probable effect on impacted small businesses.
As explained and demonstrated above, the costs and impacts on small businesses are expected to be minimal. Many of these costs and impacts will be offset by more regulatory clarity and certainty, which should reduce development costs.

(d) A description of any less intrusive or less costly alternative methods of achieving the purpose of the proposed regulation.
Many of the regulation changes were added to provide clarity and certainty to minimize cost and time needed to develop projects, obtain certification and to comply with both the AEPS Act and the Public Utility Code. Where additional administrative and reporting requirements were added, § 75.17 (process for obtaining Commission approval of customer-generator status for systems with a nameplate capacity of 500 kilowatts or greater) or § 75.72 (reporting requirements for quarterly adjustment of non-solar Tier I obligation), the known least intrusive and least costly alternative method was used.

(25) List any special provisions which have been developed to meet the particular needs of affected groups or persons including, but not limited to, minorities, the elderly, small businesses, and farmers.

The Commission established an exemption to the 200% design limit for alternative energy systems that are set up and designed to comply with the Chesapeake Watershed Implementation Plan or the Nutrient Management Act, which would include small businesses and farmers that must meet the requirements of the Chesapeake Watershed Implementation Plan and the Nutrient Management Act.

(26) Include a description of any alternative regulatory provisions which have been considered and rejected and a statement that the least burdensome acceptable alternative has been selected.

Regarding the definition of Distributed Generation System in Section 75.1 (Definitions) of the regulations, PECO suggested that the regulations permit only combined heat and power units that qualify for net metering to qualify as an alternative energy source. The Commission rejected this suggestion as it would create an unnecessary and unwarranted burden on such system developers. See Final Rulemaking Order at 11.

Regarding the 200% design size limit in Section 75.13(a)(3), the Commission originally proposed that this limit be 110% of historical load, which several commentators supported. Based on the comments received, the Commission increased the limit to 200% and created an exemption for systems built and designed to meet the Chesapeake Watershed Implementation Plan or the Nutrient Management Act. These modifications provide more flexibility for system sizing and for farmers that have environmental compliance requirements, while at the same time limiting the burdens placed on other ratepayers and ensuring that their rates are just and reasonable and meets default service at the least cost to customers over time requirements found in the Public Utility Code.

Regarding the calculation of the price to compare for determining each year end payment to customer-generators with excess generation in Section 75.13(e), the Commission considered a requirement that the default service provider use a weighted average of the price to compare. Based on comments, the Commission determined that "the proposed language created more confusion, as it results in varied outcomes based on the particular rate, such as time-of-use and real-time price plans, and multiple interpretations based on the rate." Final Rulemaking Order at 71. The Commission further stated that it "will continue our current practice of reviewing and approving each EDC's tariff provisions addressing this compensation during base rate and default service rate proceedings that provide an opportunity for all effected stakeholders to be heard and to propose alternatives." *Id.*

Regarding the definition of "year and yearly" in Section 75.12 (Definitions), the Commission initially proposed to change the definition from the PJM planning year to May 1 through April 30 to help align the year with the solar photovoltaic peak production periods. The Commission revised it to June 1 through May 31, which is the PJM planning year, to reduce cost burdens on EDCs that are borne by ratepayers. See Final Rulemaking Order at 89.

Regarding the approval process for large customer-generator facilities in Section 75.17, the Commission stated the following:

> the Commission finds that this approval process ensures uniform and consistent application of the net metering rules throughout the Commonwealth and that administrative efforts and costs will be minimal due to the small number of such systems

applying for net metering in a year. We stress that the Commission's review is simply to ensure that those entities that claim to meet the definition of customer-generator do in fact meet that definition, as expressed in the AEPS Act and the Commission's regulations. In addition, the Commission's review will ensure that the virtual meter aggregation provisions in the AEPS Act and the Commission's regulations are complied with.

Final Rulemaking Order at 62. In addition, the Commission revised the timelines to reduce the burdens on EDCs and noted that the timeline is to run concurrent with the interconnection application timeline, reducing delays and burdens on the applicants. See Final Rulemaking Order at 99.

Regarding the meter requirement for small solar photovoltaic systems with a nameplate capacity of 15 kilowatts in Section 75.63(g), the Commission noted that while removing the ability of these systems to use estimates may cause an inconvenience, it would ensure the validity of the credits. The Commission also noted that solar photovoltaic systems may use inverter reads (inverters are used on all solar photovoltaic systems to convert the direct current power produced by the photovoltaic panels to alternative current that is sent to the grid or used on site), thus reducing costs for purchasing a revenue grade meter and providing flexibility. See Final Rulemaking Order at 111.

Regarding the reporting requirements in Section 75.72, the Commission extended the EDC reporting requirements by five days, reducing the burden on the EDCs, but at the same time providing adequate time for EGSs to review and verify the reported data. It also provides adequate time for the Program Administrator to use the data to compute the quarterly Tier I requirements and give all EDCs and EGSs the new requirements in a timely manner so that they can develop plans to acquire the requisite credits for compliance. See Final Rulemaking Order at 120-121.

(27) In conducting a regulatory flexibility analysis, explain whether regulatory methods were considered that will minimize any adverse impact on small businesses (as defined in Section 3 of the Regulatory Review Act, Act 76 of 2012), including:

a) The establishment of less stringent compliance or reporting requirements for small businesses;
b) The establishment of less stringent schedules or deadlines for compliance or reporting requirements for small businesses;
c) The consolidation or simplification of compliance or reporting requirements for small businesses;
d) The establishment of performing standards for small businesses to replace design or operational standards required in the regulation; and
e) The exemption of small businesses from all or any part of the requirements contained in the regulation.

Other than providing additional clarity and regulatory certainty, the requirement for Commission approval of applications for net metering was limited to systems with a nameplate capacity of 500 kilowatts or greater, which are systems not typically installed at small businesses. In addition, regarding the quarterly reporting requirement in § 75.72, the Commission only required the EGSs to verify the monthly sales data submitted by the EDCs. This method reduces the burden on small EGSs by not requiring them to enter data for sales in each EDC service territory; they simply have to verify that the data entered by the EDC is correct.

(28) If data is the basis for this regulation, please provide a description of the data, explain in detail how the data was obtained, and how it meets the acceptability standard for empirical, replicable and testable data that is supported by documentation, statistics, reports, studies or research. Please submit data or supporting materials with the regulatory package. If the material exceeds 50 pages, please provide it in a searchable electronic format or provide a list of citations and internet links that, where possible, can be accessed in a searchable format in lieu of the actual material. If other data was considered but not used, please explain why that data was determined not to be acceptable.

Experience in implementing the AEPS Act and the default service provisions of the Public Utility Code have provided the basis for most of the proposed regulation changes. Much of the data contained in the Commission's AEPS Act annual report also informed the Commission on the need for the proposed changes. Specifically: Section 2 Status of Compliance, for cost of compliance and origins of credits, as well as the status of customer-generator interconnections; Section 3 Costs and Benefits of Alternative Energy Generation and renewable energy economic benefits; and Section 4 Status of PA's Alternative Energy Portfolio Standards Marketplace. This information not only provides the Commission with the current status of alternative energy in Pennsylvania, it also provides trends over the years that inform the Commission on potential issues and concerns. A copy of the latest Annual Report is available at http://www.puc.pa.gov/Electric/pdf/AEPS/AEPS_Ann_Rpt_2014.pdf. All Annual Reports are available on the following Commission webpage: http://www.puc.pa.gov/consumer_info/electricity/alternative_energy.aspx.

(29) Include a schedule for review of the regulation including:

A. The date by which the agency must receive public comments:	N/A
B. The date or dates on which public meetings or hearings will be held:	N/A
C. The expected date of promulgation of the proposed regulation as a final-form regulation:	N/A
D. The expected effective date of the final-form regulation:	upon publication as final
E. The date by which compliance with the final-form regulation will be required:	upon publication as final
F. The date by which required permits, licenses or other approvals must be obtained:	N/A

(30) Describe the plan developed for evaluating the continuing effectiveness of the regulations after its implementation.

The Commission will continue to work with EDCs, EGSs, customer-generators, interested members of the public, and other state agencies to determine whether the regulatory provisions of the AEPS Act require further interpretation or clarification.

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BY _____ (DEPUTY ATTORNEY GENERAL)	Pennsylvania Public Utility Commission (AGENCY)	BY Bohdan R. Pankiw, Chief Counsel
_____ DATE OF APPROVAL	DOCUMENT/FISCAL NOTE NO. L-2014-2404361/57-304	2/11/16 DATE OF APPROVAL
	DATE OF ADOPTION February 11, 2016	
	BY Rosemary Chiavetta	
☐ Check if applicable Copy not approved. Objections attached	TITLE Secy (SECRETARY)	☐ Check if applicable. No Attorney General approval or objection within 30 days after submission.

L-2014-2404361/57-304
Final Rulemaking
Implementation of the Alternative Energy
Portfolio Standards Act of 2004
52 Pa Code, Chapter 75

The Pennsylvania Public Utility Commission on February 11, 2016, adopted a final rulemaking order amending existing regulations to comply with Act 129 of 2008 and Act 35 of 2007, and to clarify issues of law, administrative procedure and policy. The contact person is Assistant Counsel Kriss Brown, Law Bureau, 717 787-4518.

EXECUTIVE SUMMARY

L-2014-2404361/57-304

Final Rulemaking

Implementation of the Alternative Energy Portfolio Standards Act of 2004

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 has revised 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, and the Pennsylvania Public Utility Code, 66 Pa. C.S. §§ 101 *et. seq.*, as well as to clarify certain issues of law, administrative procedure, and policy.

The contact persons for this Final Rulemaking are Assistant Counsel Kriss Brown (717) 787-4518, Analyst Joseph Sherrick (717) 787-5369, and Analyst Scott Gebhardt (717) 425-2860.

PENNSYLVANIA
PUBLIC UTILITY COMMISSION
Harrisburg, PA 17105-3265

Public Meeting held February 11, 2016

Commissioners Present:

Gladys M. Brown, Chairman, Statement, Dissenting
Andrew G. Place, Vice Chairman, Statement, Dissenting
Pamela A. Witmer
John F. Coleman, Jr.
Robert F. Powelson, Statement

Implementation of the Alternative Energy Portfolio Standards Act of 2004

Docket No. L-2014-2404361

FINAL RULEMAKING ORDER

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Annex A

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. The Commission has received and reviewed numerous public comments and is issuing final rules 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.

The Commission issued a Notice of Proposed Rulemaking (NoPR) for comment on February 20, 2014. *See Implementation of the Alternative Energy Portfolio Standards Act of 2004*, Proposed Rulemaking Order, Docket No. L-2014-2404361 (Order entered February 20, 2014). The Proposed Rulemaking Order and proposed rules were published in the *Pennsylvania Bulletin* on July 5, 2014, at 44 Pa.B. 4179. Comments were due within 30 days of the publication of the proposed rules in the *Pennsylvania Bulletin* or August, 4, 2014. On August 1, 2014, the Commission, at the request of the Pennsylvania Department of Agriculture, issued a Secretarial Letter extending the comment period to September 3, 2014. Comments were received from the Independent Regulatory Review Commission and many other interested parties.

Other parties filing comments included Acuity Advisors and CPAs; the Ad Hoc Coalition of Customer Generators; Robin Alexander; the American Biogas Council (ABC); Karen Berry; Brubaker Farms; Vincent Cahill & Claire Hunter; the Center for Dairy Excellence; Chesapeake Bay Commission; Chesapeake Bay Foundation; Citizen Power; Citizens for Pennsylvania's Future and the PennFuture Energy Center (PennFuture); Crayola, Inc. (Crayola); Dauphin County Board of Commissioners; the Dauphin County Industrial Development Authority (DCIDA); Pennsylvania Department of Agriculture (PDA); Duquesne Light Company (Duquesne); the Distributed Wind Energy Association and United Wind et al. (DWEA/UW); the Energy Association of Pennsylvania (EAP); Enviro-Organic Technologies, Inc.; the Estate Security Formula / Gary L. James; State Representative Garth Everett; State Representative Robert L. Freeman; State Representatives Mindy Fee & David Hickernell; Granger Energy of Honey Brook LLC and Granger Energy of Morgantown LLC (Granger); Keith Hodge; the House Committee on Agriculture and Rural Affairs; Ideal Family Farms, LLC; Kish

View Farm; L&S Sweeteners; Lancaster County Agriculture Council; Lancaster County Conservation District (LCCD); Lancaster Veterinary Associates (LVA); Lancaster County Solid Waste Management Authority (LCSWMA); Lehigh County Authority; Elsa Limbach; Kurt Limbach; Lycoming County Commissioners; the Mid-Atlantic Renewable Energy Association; Metropolitan Edison Company, Pennsylvania Electric Company, Pennsylvania Power Company, and West Penn Power Company (FirstEnergy); the Pennsylvania Milk Marketing Board; Larry Moyer; the Neighbors of Yippee Farms; the Office of Consumer Advocate (OCA); Oregon Dairy, Inc. (Oregon Dairy); the Office of Small Business Advocate (OSBA); Paradise Energy Solutions (PES); Professional Dairy Managers of Pennsylvania (PDMP); PECO Energy Company (PECO); PennAg Industries Association (PennAg); Pa Biomass Energy Association; DEP; Pennsylvania Farm Bureau (Farm Bureau); Pennsylvania Municipal Authorities Association; Pennsylvania State University (PSU); Pennsylvania Waste Industries Association; PJM Interconnection, LLC (PJM); PPL Electric Utilities Corporation (PPL); RCM International LLC; Reinford Farms; the Retail Energy Supply Association (RESA); the Sustainable Energy Education & Development Support of Northeast Pennsylvania; Sensenig Dairy; Sierra Club and Sierra Club Members & Supporters (Sierra Club); Solare America; SRECTrade, Inc. (SRECTrade); Sunrise Energy, LLC (Sunrise); the Sustainable Energy Fund (SEF); Tetra Tech, Inc.; the United States Department of Justice, Federal Bureau of Prisons (DOJ); State Representative Greg Vitali; Wanner's Pride-N-Joy Farm, LLC; John R. Williamson; State Senator Gene Yaw; and Yippee Farms.

The Commission issued an Advance Notice of Final Rulemaking (ANoFR) for comment on April 23, 2015. *See Implementation of the Alternative Energy Portfolio Standards Act of 2004*, Advance Notice of Final Rulemaking Order, Docket No. L-2014-2404361 (Order entered April 23, 2015). The Advance Notice of Final Rulemaking Order and proposed rules were published in the *Pennsylvania Bulletin* on

May 9, 2015, at 45 Pa.B. 2242. Comments were due within 20 days of the publication of the proposed rules in the *Pennsylvania Bulletin* or May 29, 2015.

Comments were received from Ar-Joy Farms LLC; Arlin Benner and Family; Brubaker Farms (dated 5/25/15 and 5/26/15); the Center for Dairy Excellence; Citizen Power; (PennFuture); Crayola, Inc.; DCIDA; DEP; Duquesne; EAP; FirstEnergy; State Representative Robert W. Godshall (dated 4/27/15 and 5/26/15); Granger; Hard Earned Acres, Inc.; PennFuture, the Clean Air Council, the Reinvestment Fund, the Mid-Atlantic Renewable Energy Association (MAREA), the Sierra Club, the Solar Unified Network of Western Pennsylvania (SUNWPA), and the Pennsylvania Solar Energy Industries Association (hereinafter Joint Commentators); Kish View Farm; Herb Kreider; Land O'Lakes, Inc. (Land O'Lakes); State Representative John A. Lawrence; LCSWMA; the League of Women Voters of Pennsylvania (LWV); Lycoming County Commissioners (dated 5/1/15 and 5/27/15); MAREA; MAREA et al; Larry Moyer; the National Milk Producers Federation (Milk Producers); Oakhill Farm; OCA; OSBA; PES; PDA; PDMP; PECO; the PennEnvironment Research and Policy Center; Farm Bureau; Pennsylvania Interfaith Power & Light (PA IPL); Pennsylvania State Grange (PSG); PSU; Pennsylvania Waste Industries Association (PWIA); PPL; RCM International LLC; Reinford Farms; Schrack Farms; Sensenig Dairy; SolarCity; Sunrise (dated 4/24/15, 5/2/15, 5/14/15, 5/15/15, 5/16/15 and 6/5/15); SUNWPA; TeamAg Inc.; and Turkey Hill Dairy.

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).

- Clarification of entities that do not qualify for net metering subsidies.

- 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, most of these small alternative energy system owners have difficulty selling the few credits they produce in a year 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.

a. Comments

In their comments, SEF, SRECTrade, and PPL support the changes proposed in the NoPR, and suggest minor modifications. SEF NoPR comments at 2, SRECTrade NoPR comments at 2, PPL NoPR comments at 4.

b. Disposition

Consequently, a slight change was made to the definition for aggregator in the ANoFR. Comments supporting the proposed revised definition in the ANoFR were received from PPL and FirstEnergy. PPL ANoFR comments at 4, FirstEnergy ANoFR comments at 2. As such, we adopt the definition of aggregator as proposed in the ANoFR.

2. Alternative Energy Sources

The definition of alternative energy sources was 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. *See* 66 Pa.C.S. § 2814.

a. Comments

SEF and PPL submitted comments supporting the proposed revisions. SEF NoPR comments at 2, PPL NoPR comments at 4, PPL ANoFR comments at 4. FirstEnergy submits comments opposing the proposed revision in the NoPR to the definition of Tier II alternative energy sources. FirstEnergy believes that the Commission intended for generation of electricity utilizing by-products of the pulping process and wood manufacturing process to be from facilities located *within* the commonwealth rather than *outside*. FirstEnergy recommends making changes to the proposed revision to the definition of Tier II alternative energy sources. FirstEnergy NoPR comments at 4.

b. Disposition

The Commission declines to adopt FirstEnergy's proposal as FirstEnergy's request is based on a faulty conclusion, as generation of electricity utilizing by-products of the pulping process and wood manufacturing process to be from facilities located *within* the Commonwealth is now under the definition of biomass energy and is a Tier I alternative

energy source. Whereas electricity generation utilizing by-products of the pulping process and wood manufacturing process from facilities located *outside* the Commonwealth remains a separate Tier II alternative energy source.

3. Low-impact Hydropower

The definition of low-impact hydropower was revised in the ANoFR to reflect amendments to the definition for low-impact hydropower from Act 129. Language was added to clarify that only changes made to an existing hydroelectric power plant after the effective date of the AEPS Act will be considered incremental. No opposing comments were received to the proposed changes to the definition in the ANoFR. As such, we adopt the proposed amendments to the definition of low-impact hydropower and biomass facilities proposed in the ANoFR.

4. Distributed Generation System

We have also proposed more precise definitions for elements of the definition for distributed generation systems, which is defined in the AEPS Act as "the small-scale power generation of electricity and useful thermal energy." 73 P.S. § 1648.2. 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 as to which 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 to the definition of distributed generation systems. 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.

a. Comments

In their comments, PPL supports the changes proposed in the NoPR and ANoFR to the definition for distributed generation systems. PPL, however, is concerned that the term "useful thermal energy" is subjective and could result in different and possibly conflicting interpretations regarding whether such energy is eligible for purposes of net metering. PPL recommends that the Commission provide further clarification. PPL NoPR comments at 4-5, PPL ANoFR comments at 6-7.

Comments provided by PECO to the ANoFR state that the proposed revised definition will indicate that distributed generation systems may not have a nameplate capacity that is greater than five megawatts. 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. PECO, based on the proposed language, states that customers may mistakenly believe that it is acceptable to interconnect a distributed generation system between three and five megawatts without having to comply with the requirements and specifications contained in the definition of

customer-generator. To avoid such misunderstandings, PECO recommends that the Commission revise the proposed regulations to clarify that distributed generation systems with nameplate capacities between three and five megawatts are only allowable if they comply with the requirements set forth in the definition of customer-generator. PECO ANoFR comments at 3.

Sunrise states in its ANoFR comments that it seems as if the Commission intends to preclude the use of combined-cycle electric generation from net metering. Sunrise ANoFR comments in a letter dated 6/5/15.

b. Disposition

We agree in part and disagree in part with PECO's recommendation that distributed generation systems sized between three and five megawatts are only allowable if they comply with the requirements set forth in the definition of customer-generator. For purposes of net metering, we agree with PECO that a customer with a distributed generation system sized between three megawatts and five megawatts must comply with the requirements set forth in the definition of customer-generator and be approved under the appropriate interconnection procedures. We, however, disagree that such restrictions apply to distributed generation systems that are not receiving net metering. The AEPS Act permits all defined alternative energy systems of any size to qualify as a Tier I or Tier II resource, as defined in the AEPS Act, and generate associated alternative energy credits that can be used by EDCs and EGSs for compliance obligations. PECO's suggested change would treat distributed generation systems differently from other alternative energy sources by requiring distributed energy systems to qualify for net metering to qualify as an alternative energy system. PECO has not suggested, and the Commission cannot identify, a justifiable reason to treat distributed energy systems differently. We, therefore, decline to adopt PECO's suggestion and adopt the definition of distributed generation system as proposed.

5. 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 commonly understood 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, from EGSs and from merchant generators. 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

[1] *See* WEBSTER'S NINTH NEW COLLEGIATE DICTIONARY 318 (1983).

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.

a. Comments on Customer-Generator

In their comments, PPL, Duquesne and FirstEnergy, support the changes proposed in the NoPR and ANoFR to the definition of customer-generator. PPL NoPR comments at 5-6, PPL ANoFR comments at 4-5, Duquesne NoPR comments at 2, FirstEnergy NoPR comments at 3, FirstEnergy ANoFR comments at 2. Comments to the NoPR opposing the addition of "retail electric customer" in the definition were received from Granger, PennFuture, and DWEA/UW. Granger NoPR comments at 20-22, PennFuture NoPR comments at 4-5, DWEA/UW NoPR comments at 4.

The IRRC states in their comments to the NoPR that adding the term "retail electric customer" could alter the landscape of the alternative energy market that, to some degree, relies on the third party ownership model. The IRRC asks that the Commission further explain how it ascertained that the inclusion of this term is consistent with the intent of the General Assembly and the overall purpose of the Act. IRRC NoPR comments at 5.

Sunrise, Granger, DEP, PDA, and the Farm Bureau disagree with the proposed definition of customer-generator and suggest changes in their comments to the ANoFR.

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[2] *See* WEBSTER'S NINTH NEW COLLEGIATE DICTIONARY 1300 (1983).

Sunrise avers that the Commission's proposed regulations contravene the AEPS Act and intent of the legislature by imposing size limitations on net metering. Sunrise ANoFR comments in a letter dated 5/2/15.

Granger believes the phrase "retail electric customer" should be removed from the proposed definition and that the use of the phrase is not consistent with the AEPS Act. The use of the phrase could prohibit customer-generators who manage their own internal distribution system from using a net metered alternative energy system. Granger proposes that 'grandfathering' be extended to the expansion of existing projects up to the full nameplate capacity set forth in the Act. Granger ANoFR comments at 7-8.

The DEP urges the Commission to maintain net metering rules which are flexible enough to encourage innovation in the deployment of new technologies. For example, at the residential level, retail electric customers may lease solar equipment from a solar company and allow the company to own and operate the equipment. In other instances, a farm operating a bio digester may choose to establish a separate legal entity to operate the distributed generation system. DEP ANoFR comments at 1.

The PDA echoes the comments of the DEP. PDA opposes the definition suggesting it be altered to be consistent with the change suggested for §75.13 (a)(4) by inserting "unless it is designed to produce no more than 200% of the customer-generator's annual electric consumption or satisfies the conditions set forth in §75.13 (a)(3)(IV)." PDA ANoFR comments at 2-3.

b. Disposition of Customer-Generator

We disagree with Sunrise and Granger statements that the proposed regulations contravene the AEPS Act and the intent of the legislature. The AEPS Act defines customer-generator as a "nonutility owner or operator" of the distributed generation

system. As such, the customer is defined as "one that purchases a commodity or service." Furthermore, the Public Utility Code defines customer as a retail electric customer and a direct purchaser of electric power.

In response to IRRC's comment, we initially note that net metering is only one part of the entire regulatory scheme created by the General Assembly to promote alternative energy. The primary regulatory scheme is the requirement that 18 percent of all electric retail sales to Commission jurisdictional electric service customers are to be supplied from the statutorily identified alternative energy sources.[3] This requirement is met primarily by EDCs and EGSs purchasing alternative energy credits, which are created when an alternative energy source generates one megawatt-hour of electricity. Under this scheme, the alternative energy source owner receives at least two streams of revenue from the generation of each megawatt-hour of electricity it produces: one from the actual sale of the electricity itself, and one from the sale of the alternative energy credit, which EDCs and EGSs are mandated to purchase to meet the 18 percent requirement. In addition, some of these alternative energy systems are able to receive production tax credits for each megawatt-hour of generation or investment tax credits.

While net metering is one of the regulatory schemes created to promote alternative energy, it is not available to all alternative energy systems. The General Assembly limited net metering to only customer-generators. 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, except for customers whose systems are above three megawatts and up to five megawatts who make their systems available

[3] While small scale net metered systems provide a portion of the alternative energy available to meet this 18 percent of all retail electric sales requirement, we note that meeting this requirement relies primarily on utility scale generation that is precluded from net metering by the AEPS Act.

> 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 electric distribution company, electric cooperative or municipal electric system have been promulgated by the Institute of Electrical and Electronic Engineers and the Pennsylvania Public Utility Commission.

This long and comprehensive definition has many elements that limit which persons or entities are considered as customer-generators. The rules of statutory construction require the Commission to interpret and apply this definition in a manner that gives full effect to all the words in the definition. 1 Pa. C.S. § 1921(a).

To begin with, the term itself – customer-generator – includes the term "customer" before the term "generator," expressly implying that the person or entity seeking customer-generator status must first be a customer of the EDC receiving retail electric service from the EDC. Next, the definition expressly refers to electric customers, specifically, "residential service," "other customer service locations," and "except for customers," that clearly identify the predicate that customer-generator status is entirely intended for persons or entities that are in fact electric customers. One cannot have residential service or have other customer service locations unless one is first a customer of the EDC. Furthermore, the definition specifically gives examples of retail electric customer facilities. Specifically, it mentions emergency services facilities, hospitals, traffic signals, wastewater treatment plants and telecommunications facilities, all of which are customer facilities that operate and use electric service independent of any associated alternative energy system. Adding the term "retail electric customer" to the definition of customer-generator in these regulations is consistent with the AEPS Act and makes clear and explicit what was intended by the General Assembly. Reading the definition otherwise would make the word "customer" in customer-generator and the

terms "residential service," "other customer service locations," and "except for customers," and the specific references to retail electric customer facilities superficial, meaningless and without effect.

Furthermore, the AEPS Act is replete with references and terms defined in and covered by the Public Utility Code that relate to the same persons or things or the same class of persons or things. As such, both statutes must be read in *pari materia* and construed together as one statute. *See* 1 Pa.C.S. § 1932. As discussed previously, the Public Utility Code defines a customer as "[a] retail electric customer." *See* 66 Pa.C.S. § 2803. Accordingly, the definition of customer-generator applies to retail electric customers and is adopted as proposed.

c. Comments on Utility

PPL and Duquesne submitted comments supporting the changes proposed in the NoPR and ANoFR to the definition of utility. PPL NoPR comments at 6, PPL ANoFR comments at 7, Duquesne NoPR comments at 3.

Granger, DCIDA, Solare America, LCSWMA, DOJ and numerous other parties feel that the proposed definition of utility excludes net metering projects involving companies that do not fit the new definition. Granger NoPR comments at 17-20, DCIDA NoPR comments at 9-13, Solare America NoPR comments at 1, LCSWMA NoPR comments at 1, DOJ NoPR comments at 1-2.

PennFuture, the American Biogas Council, Citizen Power, and many other commentators stated that the proposed definition of utility is too broad and a threat to the "third-party ownership" model. PennFuture NoPR comments at 3-4, the American Biogas Council NoPR comments at 2-3, Citizen Power NoPR comments at 2.

In their comments, the IRRC noted that commentators indicated that the definition of utility is overly broad and could be interpreted to include entities not intended by the Commission, such as landlords. Concerns have been raised that this definition, read in conjunction with the revised definition of customer-generator, would threaten the third-party ownership model. The IRRC asks the Commission to provide a more precise definition of this term and to consider using the statutory term "public utility." IRRC NoPR comments at 5.

PSU comments strongly emphasize that non-profits are not eligible for tax breaks and must partner with 'third parties' for the capital needed to finance renewable energy projects. PSU NoPR comments at 3-7.

Based on suggestions and comments from stakeholders that were received in regards to the proposed changes in the NoPR, the definition of utility was amended in the ANoFR to exclude persons or entities that own or operate alternative energy systems that are clearly not merchant generators.

Comments opposing the changes proposed in the ANoFR to the definition of utility were received from many parties. PES, Citizen Power, and others believe that the definition is still too broad and request changes to the definition of utility. RCM International LLC, PDMP, PDA, and many other parties feel that the definition of utility may conflict with the 200% limitation waiver found in §75.13(a)(3)(IV) and request the definition be subject to § 75.13(a)(3)(IV). Sunrise avers that the word 'public' was dropped in haste and that the Commission should cease from gratuitous wordsmithing. PDA ANoFR comments at 1-2, Citizen Power ANoFR comments at 2, RCM International LLC ANoFR comments at 1, PDMP ANoFR comments at 2, PES ANoFR comments at 1, Sunrise ANoFR comments in a letter dated 4/24/15.

The Lycoming County Commissioners request in their comments to the ANoFR that clarity be provided by adding that a utility is a person or entity that provides electric generation, transmission or distribution services at wholesale or retail, to other persons or entities for the public good and who are regulated by the public utility commission. Lycoming County Commissioners ANoFR comments at 1-2 in a letter dated 5/1/15 and 1-3 in a letter dated 5/27/15.

DCIDA submits that the proposed definition of utility is confusing and will generate misunderstandings. The size limitation language used in the definition creates a situation where existing facilities could be considered not eligible for net metering. DCIDA avers that the Commission has not satisfied the criteria to promulgate the proposed definition and that said definition is not in the public interest. DCIDA ANoFR comments at 6-8.

In their comments addressing the definition of utility, LCSWA, PPL, and others request that all existing net metering installations be allowed to continue net metering and not be subject to the proposed definition of utility. LCSWA ANoFR comments at 1, PPL ANoFR comments at 15.

d. Disposition of Utility

As discussed above, the Commission must interpret and apply the definition of customer-generator in a manner that gives full effect to all the words in the definition. 1 Pa. C.S. § 1921(a). The definition of customer-generator specifically states that they are "[a] nonutility owner or operator of a net metered distributed generation system...." 73 P.S. § 1648.2. As such, only distributed generation systems owned and operated by nonutilities can qualify as a customer-generator. Or, in other words, a distributed generation system that is owned or operated by a utility cannot qualify as a

customer-generator. The Commission has determined that it is easier to identify what a utility is as opposed to identifying all persons or entities that are not utilities.

To begin with, neither the term nonutility nor the term utility is defined in the AEPS Act. Nor are they defined in the Public Utility Code. The Public Utility Code, does however, define the term "public utility," which several parties state should be used for the purposes of the term "nonutility" in the definition of customer-generator. The Public Utility Code, in part, defines a public utility as follows:

> (1) Any person or corporation now or hereafter owning or operating in this Commonwealth equipment or facilities for:
> (i) Producing, generating, transmitting, distributing or furnishing natural or artificial gas, electricity, or steam for the production of light, heat, or power to or for the public for compensation.

See 66 Pa. C.S. § 102. The Public Utility Code goes on to indicate which persons or entities are not public utilities. Specifically, the Public Utility Code indicates, in part, the term "public utility" does not include the following:

> (2) The term does not include:
> (i) Any person or corporation, not otherwise a public utility, who or which furnishes service only to himself or itself.
> ....
> (v) Any building or facility owner/operators who hold ownership over and manage the internal distribution system serving such building or facility and who supply electric power and other related electric power services to occupants of the building or facility.
> (vi) Electric generation supplier companies, except for the limited purposes as described in sections 2809 (relating to requirements for electric generation suppliers) and 2810 (relating to revenue-neutral reconciliation).

Id. As the Public Utility Code explicitly excludes from the definition of "public utility" persons or entities that furnish services only to themselves, or who manage the internal distribution system serving occupants of a building or facility they own and operate, or EGSs, the term "public utility" is not synonymous with the use of the word "utility" in the

definition of customer-generator. Had the General Assembly intended to specifically exclude persons or entities that furnish services only to themselves, or who manage the internal distribution system serving occupants of a building or facility they own and operate, or EGSs, from the term "utility" in the definition of the customer-generator, it would have specifically included the term "public utility" in that definition.

But the General Assembly did not use the term "public utility" in the definition of customer-generator. Therefore, we must presume that the General Assemble intentionally chose the term "utility" in this definition for another reason. Initially, we note that the AEPS Act involves the generation of electricity by specifically identified alternative energy systems of any size or capacity. We also note that since the restructuring of the electric utility industry with the enactment of the Electric Generation Customer Choice and Competition Act (Electric Competition Act), 66 Pa. C.S. §§ 2801, *et seq.*, in 1996, no electric public utility owns or operates electric generation facilities. The Electric Competition Act specifically required the:

> electric utilities to unbundle their rates and services and to provide open access over their transmission and distribution systems to allow competitive suppliers to generate and sell electricity directly to consumers in this Commonwealth. The *generation of electricity will no longer be regulated as a public utility* function except as otherwise provided for in this chapter. Electric generation suppliers will be required to obtain licenses, demonstrate financial responsibility and comply with such other requirements concerning service as the commission deems necessary for the protection of the public.

66 Pa. C.S. § 2802(14) (emphasis added). The Commission must presume that the General Assembly knew this fact when it enacted the AEPS Act on November 30, 2004, almost eight years after it enacted the Electric Competition Act. Therefore, as no public utility has owned or operated electric generation facilities since the implementation of the Electric Competition Act in the 1990s, it would make the word "nonutility" surplus language if it were interpreted as meaning "nonpublic utility," which the rules of statutory

construction preclude. *See* 1 Pa. C.S. § 1921; *see also Commonwealth v. Ostrosky*, 909 A.2d 1224, 1232 (Pa. 2006).[4]

Finally, the rules of statutory construction preclude an interpretation that would produce a result that was "unreasonable." 1 Pa. C.S. § 1922(1). Net metering allows the customer-generator to obtain above-market prices for electricity produced by certain alternative energy resources. This benefit is subsidized by ratepayers and constitutes a transfer of wealth from the utility's general body of ratepayers to customer-generators in order to promote alternative energy resources. However, to allow *de facto* merchant generators to obtain the customer-subsidized benefits of net metering would be, in the Commission's judgement, an unreasonable interpretation of the statute and would result in unjust and unreasonable rates.

For these reasons, the Commission finds that the General Assembly had a broader interpretation of the term "utility" in mind when it defined customer-generator to include any person or entity that provides electric generation, transmission or distribution services, at wholesale or retail, to other persons or entities, and that this term includes within its scope, merchant generators. These are entities that do not qualify for net metering subsidies.

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[4] We also note that the definition of customer-generator in the AEPS Act specifically references critical infrastructure such as wastewater treatment plants and telecommunications facilities, both of which are owned and operated by public utilities. See 66 Pa. C.S. § 102 (definition of Public utility (1)(vi) "conveying or transmitting messages or communications . . ., by telephone or telegraph ...." And (1)(vii) "Sewage collection, treatment, or disposal for the public for compensation."). Accordingly, interpreting the term "nonutility" as meaning "nonpublic utility" would preclude public utilities that own and operate wastewater treatment plants and telecommunications facilities from qualifying as customer-generators. There is no indication in the AEPS Act that indicates that only owners and operators of wastewater treatment plants and telecommunications facilities that are not regulated public utilities can qualify as a customer-generator. Again, interpreting "nonutility" to mean "nonpublic utility" would create a direct conflict within the statute. We must interpret the statute in a manner that gives effect to all provisions, if possible. *See* 1 Pa. C.S. § 1933.

We, however, do not find that the definition was intended to be so broad that it would preclude, from qualifying for net metering subsidies, persons or entities that own or operate distributed generation systems to supply their own power needs or to buildings or facilities they own and where they manage the internal distribution system serving such buildings or facilities. Accordingly, we revised the definition of utility to exclude owners or operators of an alternative energy system that is designed to produce no more than 200% of a customer-generator's annual electric consumption or that satisfies the conditions set forth in §75.13(A)(3)(iv). We also added language that excludes building or facility owner/operators that manage the internal distribution system serving such building or facility and that supply electric power and other related power services to occupants of the building or facility.

Regarding comments that suggest that this definition should only be applied to new facilities, the Commission declines to adopt such a provision. As noted throughout this rulemaking, the Commission is revising the regulations to provide clarity to all interested parties and to facilitate uniform application throughout the Commonwealth. As this provision is simply providing clarity as to what the term "nonutility" means in the definition of customer-generator as enacted in the AEPS Act, and as the Commission is charged by the General Assembly to carry out the responsibilities delineated within the AEPS Act, we cannot ignore this provision of the AEPS Act and must enforce it. To do otherwise, would simply permit all parties, including sophisticated parties in the business of generating electricity to claim ignorance as to the meaning of the statutory language and qualify as a customer-generator based on that ignorance or misinterpretation. We note that if these parties had any question as to their status, they could have sought a declaratory order removing this uncertainty. *See* 66 Pa. C.S. § 331(f). To date, no party sought such relief.

6. 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 provided 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. In the proposed rulemaking we 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 proposed definition for grid emergencies came from PJM Manual 13 Emergency Operations.[5] As PJM is currently the only RTO serving Pennsylvania, this definition is appropriate.

The proposed 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.

a. Comments

Comments supporting the changes proposed in the NoPR to the definition of grid emergencies with suggestions for modification and clarification were received from PPL, FirstEnergy, PECO, and EAP. PPL NoPR comments at 6-7, FirstEnergy NoPR comments at 3, PECO NoPR comments at 3-4, EAP NoPR comments at 3.

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[5] 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.

PECO stated that it understands that the Commission's proposed definition of grid emergencies was taken from the PJM Manual 13 Emergency Operations. The manual provides guidance, rules, instructions and procedures as defined in PJM's Open Access Transmission Tariff (OATT). In light of the fact that the OATT is the authoritative document for PJM grid operations, PECO believes that the definition of grid emergencies should be based on and incorporate the OATT's complete definition of "emergency condition" for clarity and to avoid potential conflicts with FERC-approved provisions. PECO NoPR comments at 3-4.

Oregon Dairy, Inc. submitted comments opposing the changes proposed in the NoPR to the definition of grid emergencies. Oregon Dairy, Inc. avers that the proposed definition is a limitation on renewable project capacity and not a realistic route to larger projects. Oregon Dairy, Inc. NoPR comments at 2.

The Commission agreed with the comments submitted by PECO and proposed a revision in the ANoFR to the definition of grid emergency to reference the PJM OATT.

PPL supports the changes proposed in the ANoFR to the definition of grid emergencies, but recommends further clarification. PPL ANoFR comments at 5.

In response to several requests for clarification and modification to the definition of grid emergencies, the Commission finds that the proposed definition covers all and any emergency and that adding supplementary language to clarify as suggested by PPL would be duplicative and unnecessary. Accordingly, we adopt the definition of grid emergencies as an emergency condition as defined in the OATT or successor document, as proposed in the ANoFR.

In their comments, PPL and FirstEnergy, support the changes proposed in the NoPR and ANoFR to the definition of microgrid with FirstEnergy proposing several edits to the definition. PPL NoPR comments at 6, PPL ANoFR comments at 6, FirstEnergy NoPR comments at 4.

b. Disposition

The edits to the proposed definition of "microgrid" suggested by FirstEnergy provide clarity, specifically applicable to EDC distribution systems. As these regulations relate to EDC distribution systems, we find that the added clarity suggested by FirstEnergy to be appropriate and have adopted the definition of microgrid with the edits suggested by FirstEnergy.

7. 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 proposed 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.

a. Comments

Comments supporting the changes proposed in the NoPR to the definition of moving water impoundments were received from PECO, PPL and FirstEnergy. PECO NoPR Comments at 4, PPL NoPR Comments at 7, PPL ANoFR Comments at 6, FirstEnergy NoPR comments at 2-3. PECO, however, believes that the language should be expanded to make it clear that systems that do not directly involve naturally flowing water (in rivers and streams), such as systems that generate electricity by removing water

from the natural flow, placing it in a containment tank and then using the pressure reducing valves, would not qualify as moving water impoundments. PECO NoPR Comments at 4.

b. Disposition

We appreciate PECO's suggestion to add language to the definition in an attempt to clarify that only a system that generates electricity from naturally flowing water qualifies as a moving water impoundment. We, however, find that PECO's suggested language creates ambiguity as opposed to adding clarity. We find that the proposed definition, when read in context with the definitions for large-scale hydropower and low-impact hydropower found in the AEPS Act, clearly indicates what types of impoundments would qualify. As such, the definition of moving water impoundments is adopted as proposed.

8. 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 proposed a definition for DSP that is consistent with the definition found in the Pennsylvania Public Utility Code at 66 Pa.C.S. § 2803.

a. Comments

Comments supporting the changes proposed in the NoPR to the definition of default service provider were received from PPL and FirstEnergy. PPL NoPR Comments at 7, PPL ANoFR Comments at 4, FirstEnergy NoPR Comments at 3. In its comments, FirstEnergy states that default service providers generally provide generation and transmission service. The transmission service included in the price to compare is market

based transmission service. FirstEnergy proposes to add this clarification to the definition of default service provider in order to align the definition with those services actually provided by the DSP. FirstEnergy NoPR Comments at 3. PECO avers that the definition proposed should be replaced with a reference to the statutory definition provided in the Pennsylvania Public Utility Code at 66 Pa.C.S. § 2803. PECO NoPR Comments at 4.

b. Disposition

We decline to adopt FirstEnergy's suggestion to add a reference to transmission service. The definition is not intended to identify all possible services provided by the DSP, but simply to inform what entities can be designated as the DSP and when they serve that role. We note that all DSPs must have a Commission approved default service plan that will identify what services they provide to specific rate classes and a process for determining and publicizing the price for such service. Regarding PECO's suggestion, we decline to simply reference the Public Utility Code section where the definition of DSP can be found. We find it appropriate to provide the definition in these regulations out of convenience for any interested party. Accordingly, we adopt the definition of DSP as proposed.

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.

We proposed a provision for DSPs and a move of the EGS net metering role to subsection 75.13(b) and re-lettering of 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.

a. Independent Load

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.

i. Comments

Comments supporting the above mentioned revisions proposed in the NoPR were received by PPL, OSBA, SEF, FirstEnergy, Duquesne, and EAP. PPL NoPR Comments at 8-10, OSBA NoPR Comments at 2, SEF NoPR Comments at 2, FirstEnergy NoPR Comments at 5-6, Duquesne NoPR Comments at 4-5, EAP NoPR Comments at 4-5. PPL recommends that the Commission require that independent load must be permanent and present at the customer-generator service for a customer-generator to maintain net metering status. This would help avoid situations where merchant generators install temporary load solely for the purpose of being deemed eligible for net metering. Importantly, PPL notes that those alternative energy systems that do not meet the independent load requirement are not foreclosed from receiving value for the excess generation produced by their alternative energy systems. Indeed, these facilities already have the ability to sell the excess generation in the wholesale electric market in competition with other similarly situated merchant generators. This approach will avoid

ratepayers being forced to subsidize these merchant generators, which, in turn will avoid higher rates for customers. PPL NoPR Comments at 9-10, PPL ANoFR Comments at 10-12.

Many commentators, such as Robin Alexander, Larry Moyer, Sunrise, Enviro-Organic Technologies, Inc., Granger and PSU submitted comments opposing the independent load requirement at the host meter. These commentators aver that it may not be practicable to have generation located behind a meter with load and the change is contrary to "virtual net metering." PSU avers that the "behind the meter" and "independent load requirement" contravene with the definition in the AEPS Act. Robin Alexander NoPR Comments at 2-3, Larry Moyer Part A NoPR Comments at 3-5, Larry Moyer Part B NoPR Comments at 2, Larry Moyer ANoFR Comments at 2-4, Sunrise NoPR Comments in a letter dated 7/22/14, Enviro-Organic Technologies, Inc. NoPR Comments at 2, Granger NoPR Comments at 22-27, PSU NoPR Comments at 10-11, PSU ANoFR Comments at 11-15. Other commentators, such as RCM International LLC and PDMP, oppose the independent load requirement and request an exemption for farms. RCM International LLC NoPR Comments at 2, PDMP NoPR Comments at 3. The OCA suggests clarifying language so installations at new construction projects are not excluded. OCA NoPR Comments at 2.

The IRRC requests clarification on how the independent load requirement will be implemented for new construction that may incorporate an alternative energy system and would the owner be precluded from qualifying as a customer-generator because they do not have electric load at the time of the application to the EDC or DSP. IRRC NoPR Comments at 6.

The LWV strongly objects to preventing property owners from putting solar into their own field, on their own property unless they already use electricity there. LWV

argues that the law allows a field to be used to generate electricity if it is less than two miles away and customers get full credit. The LWV believes that alternate energies need to be encouraged, supported and promoted and that the laws adequately do that. LWV ANoFR Comments in a letter dated 5/27/15.

ii. Disposition

The Commission analyzed and considered the many comments submitted by parties that oppose the proposed clarification requiring independent load. We, however, disagree with the commentators that object to the independent load requirement. We find that independent load must be present and permanent for a customer-generator to obtain and maintain net metering status. Furthermore, we are convinced that the independent load requirement of the generation facility is critical in preventing utilities, such as merchant generators, from qualifying for net metering.

As discussed previously, a customer-generator must be a nonutility retail electric customer that has either a residential or other electric service location as a predicate to qualifying as a customer-generator. Without independent electric load, there would be no establishment of a retail electric customer at a residential or other electric service location. The interconnection would simply involve generation service.

Furthermore, the term net metering is defined as follows:

> The means of measuring the difference between the electricity supplied by an electric utility and the electricity generated by a 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.

72 P.S. § 1648.2. As the customer-generator must be a retail electric customer with a residential or other service location, there must be a need for load at the customer-generator location to net against the generation from the customer-generator.

Otherwise, it would simply be a generator, not a customer-generator. This definition also requires that the customer-generator must have a requirement for electricity. Again, without independent load at the customer-generator location, there would be no requirement for electricity to net against the generation produced by the customer-generator.

Several commentators conflate the term "virtual net metering" with the term "virtual meter aggregation" in suggesting that no independent load is required at the point of interconnection of the customer-generator. Initially we note that it is these commentators, not the Commission, that are creating net metering terms and conditions that are not in the AEPS Act. The term "virtual net metering" is neither found nor defined in either the AEPS Act or the Public Utility Code. This term implies that the electric load and the generator do not have to be co-located for net metering.

We also point to the language in the AEPS Act that requires the Commission to develop technical and net metering interconnection rules as further evidence of the General Assembly's intent that independent load is required for all customer-generator interconnections. Specifically, Section 5 of the AEPS Act states the following:

> The commission shall develop technical and net metering interconnection rules for customer-generators intending to operate renewable *onsite generators* in parallel with the electric utility grid, consistent with rules defined in other states within the service region of the regional transmission organization that manages the transmission system in any part of this Commonwealth.

73 P.S. § 1648.5 (emphasis added). This requirement specifically references onsite generators in relation to net metering interconnection for customer-generators. The reference to onsite generation demonstrates the clear intent by the General Assembly that customer-generators must be behind the meter generation. What many of the commentators refer to as virtual net metering, which again is neither referenced in nor

defined in the AEPS Act, involves offsite generation that is connected to no load and is simply connected directly to the grid. Had the General Assembly intended customer-generators to virtually net meter offsite generation, they would have simply stated that the Commission shall develop technical and net metering interconnection rules for customer-generators intending to operate renewable generators in parallel with the electric utility grid. But that is not what the General Assembly enacted.

In contrast, the AEPS Act does permit net metering for "[v]irtual meter aggregation on properties owned or leased and operated by a customer-generator and located within two miles of the boundaries of the customer-generator's property and within a single electric distribution company's service territory...." 73 P.S. § 1648.2 (definition for Net Metering). This term references the aggregation of two or more electric service meter locations virtually, as opposed to physically connecting all meter service locations, operated by one customer. Such customers may include a farm or commercial business with multiple dislocated barns or buildings that have separate electric service locations that are under one account holder. In this scenario, the operator may install an alternative energy system at one of the two or more service locations and net meter the generation from that system against the load requirements at all of the service locations, provided they are within two miles of each other and are within the same EDC service territory. To interpret this as being equivalent to virtual net metering would be creating ambiguity where none exists in the language contained in the AEPS Act. We also note that interpreting virtual meter aggregation as virtual net metering would permit a person to install an alternative energy system with a nameplate capacity greater than 50 kW and virtually net meter their residential service, circumventing the statutory limit contained in the AEPS Act. This interpretation would lead to an absurd result that is directly contrary to the intent of the General Assembly. *See Commonwealth v. McCoy*, 962 A.2d 1160, 1168 (Pa. 2009) (the interpretation that gives effect to all of the statute's phrases and does not lead to an absurd result must prevail).

Regarding comments, including those provided by IRRC, related to independent load at new construction projects, we believe that the proposed regulation does not exclude the installation of alternative energy at a new construction site. Once the new construction is built, operational and receiving retail electric service and the alternative energy system is operating, net metering would begin at that time. If the alternative energy system is operating before the new construction is built, operational and receiving retail electric load, there is nothing to net meter, so net metering would not apply. In such a scenario, the owner of the alternative energy system could sell the power from the facility at an avoided cost of wholesale power in accordance with federal and state regulations until the new construction is operational.

Finally, regarding the permanency of the independent load at the customer-generator location, we find that no additional language is needed in the regulations. To qualify for net metering and to be a customer-generator, there must be independent load. If there is no independent load, then the alternative energy system would simply be a generator and no longer qualify for net metering at that point in time. For these reasons, we adopt the requirement for independent load as proposed in the NoPR.

b. Nonutility

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.

i. Comments

Comments supporting the above mentioned proposed condition were received from Duquesne, PPL and FirstEnergy. Duquesne NoPR Comments at 3, PPL NoPR Comments at 8, FirstEnergy NoPR Comments at 5.

Granger, Crayola, DOJ, Tetra Tech, Inc., PSU and numerous other stakeholders filed opposing comments. Granger NoPR comments at 17-20, Crayola NoPR Comments at 1-2, DOJ NoPR Comments at 1-2, Tetra Tech, Inc. NoPR Comments at 2, PSU NoPR Comments at 3-7.

Oregon Dairy, Solare America and LCSWA, feel that all renewable projects involving "parties in the business of providing electric service" (merchant generators) will be disqualified from the net metering program. Oregon Dairy NoPR Comments at 2, LCSWA NoPR Comments at 1, Solare America NoPR Comments at 1.

In its comments to the ANoFR, the National Milk Producers Federation and Land O'Lakes suggest inserting the phrase "which is primarily in the business of providing electric power to the grid or other users" to the section to provide clarity for dairy farms. National Milk Producers Federation ANoFR Comments at 2, Land O'Lakes ANoFR Comments at 1.

DCIDA states that it has concern it will be unfairly categorized as a utility. The AEPS Act provides that net metering is available to "non-utility" energy generators. But, the Commission is engaged in efforts to define certain "non-utility" energy generators as "utilities" for purposes of the AEPS Act so that they are not eligible to net meter. DCIDA expressed concern for potential confusion because the Commission continues to propose a definition that departs from statutory definitions, published guidelines and established precedent to create the proposed definition. DCIDA ANoFR Comments at 5-8.

ii. Disposition

The AEPS Act definition for customer-generator requires that the owner or operator of the net metered distributed generation system be a nonutility. Accordingly, we adopt the condition as proposed in the NoPR for § 75.13(a)(2).

c. Size Limit

The third condition proposed in the NoPR required that the alternative energy system be sized to generate no more than 110% 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% 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 110% limitation of systems owned or operated by a customer-generator in the policy statement,[6] we proposed that this same reasonable and balanced approach be applied 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% limit was 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.[7] It is not to be used as a hard kilowatt-hour cap on the customer-generator's annual 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.[8]

i. Comments

Comments supporting the above mentioned condition were received from Duquesne, OSBA, PPL, PECO, FirstEnergy and EAP. Duquesne NoPR Comments at

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[6] *See Net Metering – Use of Third Party Operators*, Final Order at 9.
[7] *Id.* at 10.
[8] *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."

6-7, OSBA NoPR Comments at 3, PPL NoPR Comments at 10-13, PECO NoPR Comments at 5-8, FirstEnergy NoPR Comments at 5, EAP NoPR Comments at 4-5.

Many stakeholders filed comments opposing the system size restrictions for different reasons, such as lack of clarity and difficulty to determine the usage which is subject to change (weather, changes in occupancy, new construction, etc.). Other commentators stated that the size limitation conflicts with the language of the AEPS Act and the legislative intent.

In its comments, the IRRC states that commentators have questioned the Commission's statutory authority for this provision and also how it will be implemented. The IRRC asks the Commission to provide a citation to specific statutory language that would allow for the limitation being proposed under this subsection. IRRC NoPR Comments at 6.

Several parties filed comments requesting an exemption from the 110% size limitation for farm based alternative energy/anaerobic digester systems. Others felt that the proposed provisions were silent regarding the treatment of existing facilities that exceed the proposed limitation and suggested that existing facilities should be "grandfathered" and that the size limitation only be applied to future projects. As a result, the Commission proposed the following changes and modifications in the ANoFR under Section 75.13(a)(3):

1. The size limitation for alternative energy systems must be sized to generate no more than 200% 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.

2. For existing service location accounts, annual electric consumption shall be based on electric usage data from any 12 consecutive month period occurring within 60 months prior to submission of the customer-generator's interconnection request.

3. For new service location accounts, 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.

4. The 200% 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 180 days after the effective date of this rulemaking.

5. The 200% of the customer-generator's annual electric consumption limitation does 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 (relating to water quality standards and implementation plans) or is an element of a farm's approved nutrient management plan in compliance with the Nutrient Management Act at 3 PA.C.S. §§ 501, *et seq.* (relating to nutrient management and odor management).

Comments opposing the 200% size limitation proposed in the ANoFR were received from Duquesne, PPL, FirstEnergy, PECO, OSBA, and EAP. These commentators preferred the initially proposed size limitation of 110% for customer-generators. In its comments, Duquesne supports an alternative energy size limitation; however, it believes that a 200% cap is not in line with the spirit of the AEPS

Act and prefers a size limitation consistent with the Commission's initially proposed 110% cap. Duquesne asserts that the AEPS Act was enacted to encourage residential customers to offset a portion or all of their electric usage. As a 110% limitation is closer to the customer's actual usage, such a limitation decreases the ability of a customer-generator from obtaining excessive rate subsidies at the expense of other retail customers. Duquesne requests that the Commission utilize a 110% size limitation and clarify whether a credit should be received only up to the size limitation set by the Commission. Duquesne ANoFR Comments at 2-3.

PPL believes that the 110% size limitation initially proposed is more consistent with the intent of the net metering provision of the AEPS Act. PPL, however, suggests that if the 200% limitation is adopted, EDC's may have to install additional equipment to accommodate the larger sized alternative energy systems, which in turn, would increase costs to electric customers. Although PPL continues to support the 110% size limitation, it recognizes that the proposed 200% size limitation is a significant improvement over the current regulatory scheme with no cap. PPL asserts that a limit on the size of alternative energy systems for purposes of net metering is a reasonable and balanced approach to supporting the intent of the AEPS Act by limiting the potential for merchant generators to use net metering as a way to circumvent the wholesale electric market and realize retail rate subsidies at the expense of retail customers. PPL ANoFR Comments at 12-14.

FirstEnergy supports the initially proposed 110% size limit of an alternative energy system, and feels that an increase to 200% over the previous proposal's limit of 110% of customer-generator's annual electric consumption should be rejected. FirstEnergy notes that net metering customers in Pennsylvania are paid an amount for excess generation kWh that is equal to the Price to Compare, which includes certain transmission costs. FirstEnergy asserts that allowing for a 200% limit in Pennsylvania will result in a higher level of cross-subsidization whereby default service customers, who currently pay net

metering cost as part of default service charges, would be required to pay an increased amount. FirstEnergy ANoFR Comments at 2-3.

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. PECO states that the 110% rule also provides more reasonable protections to customers and guarantees protections that the proposed 200% rule cannot, such as preventing system oversizing, avoidance of merchant generators posing as customer-generators, establishment of clear jurisdictional boundaries between the Federal Energy Regulatory Commission (FERC) and the Commission, and containment of cost shifting. PECO notes that it provided seven examples of states with aggressive renewable goals in the NoPR, with only one state (Maryland) using a 200% rule. Accordingly, PECO recommends that the Commission adopt the initially proposed 110% size limit. PECO ANoFR Comments at 4-6.

OSBA and EAP also oppose the 200% size limitation increase. OSBA submits that the Commission has not fully considered the impact of excess net metering generation on default service rates for small businesses and recommends staying with the more reasonable 110% limitation. OSBA ANoFR Comments at 1-2. EAP suggests a targeted exception for agricultural customer-generators as opposed to raising the generation cap in general. If the Commission wishes to maintain consistency with "how net metering is treated in other states," the 200% limit appears excessive and not in keeping with the majority of the states. EAP ANoFR Comments at 3-4.

Many parties feel that the 200% size limitation is in conflict with the AEPS Act and legislative intent. Sunrise notes that the proposed rule would constrain the size of renewable energy systems by enforcing a size limitation established as a percentage of

onsite load. Sunrise asserts that system size limits are defined in the Act and the proposed limitations are in conflict. Sunrise ANoFR Comments in a letter dated 5/2/15.

DCIDA and Granger state that the 200% limitation is beyond the scope of the Commission's statutory authority and the intent of the General Assembly. Granger opines that consumption limits would materially harm landfill gas projects. DCIDA ANoFR Comments at 9-10. Granger ANoFR Comments at 9-14.

DEP states that a further limit on the ability to benefit from net metering is not authorized by law. DEP ANoFR Comments at 2. PWIA states that the rulemaking is unlawful because it disregards and contradicts the plain language of Act 213. PWIA asserts that the Act does not restrict consumption as a percentage of capacity, nor does it authorize the Commission to impose such restrictions. PWIA ANoFR Comments at 1-2.

Many other stakeholders, such as the Farm Bureau, Ar-Joy Farms LLC, and Herb Kreider believe that the proposed 200% size limitation will place the farmers' ability to augment their systems and still qualify for net metering in jeopardy. The Farm Bureau believes that the farmers' future ability to viably utilize on-farm generation systems to meet legal environmental requirements will be seriously compromised, even under the revised standards. The Farm Bureau asserts that the proposal to increase the limitation from 110% to 200%, while helpful, does not sufficiently take into account current and future needs farm families will have. The Farm Bureau urges the Commission to reconsider its final regulation and include language that provides for an outright farm exemption from the restriction in capacity. Farm Bureau ANoFR Comments at 2-4. Ar-Joy Farms LLC and Herb Kreider disagree with the 200% size limitation on methane digesters. Ar-Joy Farms LLC ANoFR Comments at 2, Herb Kreider ANoFR Comments in a letter dated 5/26/15.

Many more comments opposing the 200% size limitation were received from other stakeholders, such as the Joint Commentators, MAREA et al, SUNWPA, Citizen Power and OCA. The Joint Commentators opine that the Commission's authority to impose a 200% of annual load limitation remains in question and the benefits of such a limitation have not been shown to outweigh the costs. The Joint Commentators assert that providing the agriculture exclusion shows the lack of authority and necessity for the limit. Furthermore, the Joint Commentators argue that the Commission has not provided a sufficient cost-based analysis of the need for the cap and that the approach is not tailored to solve an actual problem. Joint Commentators ANoFR Comments at 6-10. MAREA et al urges the Commission to withdraw changes that would add a new generation limit on system size. MAREA et al ANoFR Comments at 1.

SUNWPA opposes the 200% size limitation proposed for solar energy systems because most solar systems are sized to meet existing demand. Its extensive experience with solar customers shows that it is extremely rare that a customer will size a system to overproduce. Placing a limit on production is a disincentive for energy efficiency and increasing the amount of solar to the grid should be encouraged in order to address climate change and to lessen impacts of air pollution that will help Pennsylvania meet the impending EPA Clean Power Plan regulations. SUNWPA ANoFR Comments at 1-2.

Citizen Power believes that the proposed 200% size limitation, as applied to residential customers, is unnecessary. Citizen Power recognizes that the purpose of the 200% limit is to exclude generation utilities and merchant generators from obtaining customer-generator status. Citizen Power supports the elimination of the 200% size limit for residential customers, at least until there is some evidence that such a restriction is necessary. Citizen Power ANoFR Comments at 2-3.

In its comments, OCA states that it recognizes the need to strike a balance between encouraging the development of alternative energy systems while preventing possible harm to ratepayers. The OCA suggests that the Commission may wish to consider whether a limitation for residential customers is necessary, asserting that there is not a significant concern with residential customers becoming a merchant generator. The OCA submits that while the 200% limit for residential customers is an improvement from the initial 110% proposal, it may still unnecessarily limit the expansion of residential solar installations. The OCA submits that it may be inefficient to place a size limitation in addition to the 50 kW capacity limit on residential solar installations. OCA ANoFR Comments at 3-4.

ii. Disposition

Regarding other commentators and IRRC's concerns with the Commission's legal authority to promulgate this provision in the Commission's regulations, the Commission has legislative rulemaking authority under Section 501 of the Public Utility Code, 66 Pa.C.S. § 501(b), which states the following:

> The commission shall have general administrative power and authority to supervise and regulate all public utilities doing business within this Commonwealth. The commission may make such regulations, not inconsistent with law, as may be necessary or proper in the exercise of its powers or for the performance of its duties.

The Commission also has broad rulemaking authority to implement the AEPS Act. *See* 73 P.S. § 1648.7(a) ("The Commission will carry out the responsibilities delineated within [the AEPS Act]"). Both the Public Utility Code and the AEPS Act relate to the purchase of electric generation for sale to retail customers. In particular, the Electricity Generation Customer Choice and Competition Act, 66 Pa.C.S. §§ 2801- 2815, relates to the restructuring and regulation of the generation, transmission and distribution of electric service, to include energy required to be purchased under the AEPS Act, 66 Pa.C.S. § 2807(e)(3.5), and the definition of additional alternative energy sources, 66 Pa.C.S.

§ 2814. The AEPS Act contains specific requirements that EGSs and EDCs procure at least 18 percent of their retail electric sales from alternative energy sources, 73 P.S. § 1648.3(b) & (c), and to pay full retail value for all energy produced by a customer-generator, including excess generation, on an annual basis, 73 P.S. § 1648.5. Furthermore, the AEPS Act specifically permits EDCs to recover all direct and indirect costs for complying with that Act, including the purchase of electricity generated from alternative energy sources, from their ratepayers on a full and current basis under 66 Pa.C.S. § 1307, as a cost of generation supply under 66 Pa.C.S. § 2807.

As these two statutes specifically refer to each other and they relate to the purchase of generation service supplies to retail electric customers, they must be construed together as one statute. See, 1 Pa.C.S. § 1932 ("Statutes or parts of statues are in pari materia when they relate to the same persons or things or to the same class of persons or things." "Statutes in pari materia shall be construed together, if possible, as one statute.") As the Public Utility Code and the AEPS Act must be construed as one statute, the Commission has broad and explicit legislative rulemaking authority, pursuant to the Public Utility Code and the AEPS Act to promulgate these regulations. *See* 66 Pa. C.S. § 501; 73 P.S. § 1648.7(a).

This reasonable size limitation is not inconsistent with either the AEPS Act or the Public Utility Code. In fact, this reasonable condition gives meaning and effect to all provisions of both statutes. *See McCoy*, 962 A.2d at 1168. To begin with, the provisions in this section fall squarely within the statutory definition of net metering and customer-generator. Specifically, these provisions permit systems that are not greater than 50 kW for residential service or not larger than 3 MW for other customer service locations and not above 5 MW for systems that are available to operate in parallel with the EDC during grid emergencies or to support a microgrid to obtain the benefits of net metering – benefits that are subsidized by all ratepayers. These provisions also permit

systems to be sized up to these limits, provided the customer has annual electric demand equal to or greater than one-half the annual output of alternative energy systems with nameplate capacities at these limits. Furthermore, these provisions ensure that the owners or operators of these systems are in fact customers and not acting as merchant generator utilities. A system that produces more than double the electricity needed at that service location is doing so more as a merchant generator than as a customer intending to offset part or all of their requirements for electricity. The AEPS Act was not intended to provide a vehicle by which merchant generators can collect retail prices for a wholesale product, financed by excess charges on utility ratepayers.

While net metering is an avenue to encourage the development of alternative energy systems, as it allows customers to produce on-site generation and recoup the cost of installing and interconnecting such systems, the need for such excessively sized systems to support such development is unnecessary and unfair to ratepayers who would be asked to finance the difference between the retail and wholesale price of the electricity produced by these oversized systems. While it may take several years to recoup the investment in these systems, we note that many of these systems last two or more decades, and no commentator has demonstrated that payments at the retail rate for all excess energy is required for two or more decades to recoup such costs. In particular, we find it significant that these same systems receive tax credits and revenue from the sale of the alternative energy credits generated by these very same systems, in addition to offsetting electric usage charges and the annual payments for the excess generation at the retail rate.

We have, however, acknowledged, as commentators stated, that anaerobic digesters used by the customer to comply with the Department's Chesapeake Watershed Implementation Plan or to comply with the Nutrient Management Act, 3 Pa.C.S. §§ 501, *et seq.*, are specifically sized to deal with the waste produced primarily by that customer's

operations. It is this waste stream, and not the motive to sell electric generation, that determines the size of such systems. As such, we have specifically exempted these systems from the 200% of annual load size limit.

Furthermore, we find that this size limit is reasonable as it is the same or higher than similar limits imposed by other states in the region. As noted in both the Proposed Rulemaking Order and the Advance Notice of Final Rulemaking Order, the Maryland Public Service Commission limits customer-generators to 200 percent of the customer-generator's baseline annual usage. *See* COMAR 20.50.10.01(D)(1)(b). In addition, Delaware limits customer-generators to no more than 110 percent of the customer's aggregate electric consumption. *See* 26 Del. Admin. Code 3001-8.6.2. Additionally, New Jersey requires that the generating capacity cannot exceed the customer's combined metered annual energy usage. *See* N.J.A.C. 14:8-7.3(a)(2). No commentator has demonstrated that these same or similar limitations imposed in other states has prevented or restricted the development of alternative energy systems in those states. We also note that as these limitations, as well as the Commission's policy statement limiting third-party owned and operated systems to 110% of annual load, have been in place for years, some more than a decade, the knowledge and ability of developers to comply with this requirement is well known and established. As such, we find that such a limit is reasonable and will not create an impediment to further development of customer-generator facilities.

Significantly, we find that the 200% limit will ensure that rates default service customers pay for generation is the least cost to customers over time and that they are just and reasonable, in compliance with Section 2807(e) and 1301 of the Public Utility Code, while at the same time permit the payment of full retail value for all excess energy produced on an annual basis. *See* 66 Pa. C.S. §§ 1301, 2807(e). All of these standards are required to be met by the Public Utility Code and the AEPS Act. Initially we note that

this limit is a design limit and not a cap on payments made to a qualifying net metering customer-generator. We recognize that customer load may vary each year based on weather, equipment upgrades, efficiency measures and increased demand due to expansion or the addition of new electric equipment, such as an electric vehicle. Setting the limit at 200% of historical load allows for future load growth, while at the same time limiting excessive oversizing of systems. In any event, at the end of each year, the customer-generator will still be paid the retail rate for all unused excess generation, as required by Section 5 of the AEPS Act, 73 P.S. § 1648.5. Regarding concerns raised by some commentators that developers may install large systems at locations with temporary load to skirt the rule, we find that at this time there is little evidence that there is adequate incentive for such misrepresentation. In addition, we note that if there is a significant change in customer load, such as the closing of a commercial establishment, or the cessation of operations at a service location, the EDC can seek to terminate net metering by demonstrating that the customer-generator no longer meets the tariffed conditions for net metering.

This limit gives effect to the requirement in the Public Utility Code that all energy purchased to provide default service to customers ensures adequate and reliable service at the least cost to customers over time. *See* 66 Pa.C.S. § 2807(e)(3.4). This requirement applies to "any type of *energy purchased* by a default service provider to provide electric generation supply service, *including energy* or alternative energy portfolio standards credits *required to be purchased under the [AEPS Act]*." *See* 66 Pa.C.S. § 2807(e)(3.5) (emphasis added). The AEPS Act requires the EDCs, as the default service provider, to purchase all excess energy from customer-generators. Accordingly, the default service provisions of the Public Utility Code apply and must meet the least cost to customers over time standard. The Commission is further required by the Public Utility Code to apply this standard to comparable types of energy sources. *Id.*

All of the alternative energy systems that generate electricity, to include wind, solar photovoltaic, hydropower, fuel cells, landfill gas, and waste coal, are operated by merchant generation owners who sell the output of these facilities through wholesale markets, auctions, requests for proposals and bilateral contracts at market competitive rates. Whereas, excess generation purchased from net metered customer-generators is purchased at the full retail rate. As we previously noted, these customer-generator facilities generate power for two or more decades, or more than 20 years, thus, the purchase of the excess from these facilities amounts to a long-term contract for such power.[9] Limiting net metered customer-generator facilities to a capacity that does not produce more than 200% of historical load will limit the amount of energy default service providers purchase at above market retail rates, ensuring that default service is provided at the least cost to customers over time.

In addition to the least cost procurement requirement, the Public Utility Code requires all rates received by any public utility to be just and reasonable. *See* 66 Pa.C.S. § 1301. The AEPS Act permits EDCs to recover any direct or indirect costs related to the AEPS Act on a full and current basis. Specifically, the AEPS Act states, in part, that:

> any direct or indirect costs for the purchase by electric distribution of resources to comply with this section, including, but not limited to, the purchase of electricity generated from alternative energy sources,..., shall be recovered on a full and current basis pursuant to an automatic energy adjustment clause under 66 Pa.C.S. § 1307 as a cost of generation supply under 66 Pa.C.S. § 2807.

73 P.S. § 1648.3(a)(3). In addition, the Public Utility Code states that:

> The default service provider shall have the right to recover on a full and current basis, pursuant to a reconcilable automatic adjustment clause under

[9] We note that the Public Utility Code limits long-term purchase contracts to no "more than 25% of the default service provider's projected default service load unless the commission, after a hearing, determines for good cause that a greater portion of load is necessary to achieve least cost procurement." *See* 66 Pa.C.S. § 2807(e)(3.2)(iii). We recognize, however, that excess generation from customer-generators is not likely to exceed 25 percent of default service load in any EDC service territory in the foreseeable future.

> section 1307 (relating to sliding scale of rates; adjustment), all reasonable costs incurred under this section and a commission-approved competitive procurement plan.

66 Pa.C.S. § 2807(e)(3.9). As noted earlier, this applies to any energy purchased, "*including energy* or alternative energy generation portfolio standards credits required to be purchased under the [AEPS Act]." 66 Pa.C.S. § 2807(e)(3.5) (emphasis added). We find that payment of the full retail rate for all excess energy produced by a net metered customer-generator, on an annual basis, to be in excess of what it would cost to purchase power from similar sources through competitive procurement methods such as the wholesale energy markets, auctions, or requests for proposals.

We find that to permit net metered customer-generators to install systems without any limits on the amount of excess power it can produce, and receive above-market prices for that unlimited excess, results in unjust and unreasonable rates paid by all other default service customers in violation of Section 1301. *See* 66 Pa. C.S. § 1301. We further find that limiting net metered customer-generator systems to a size that will generate no more than 200% of the customer-generator's annual electric consumption will place a reasonable limit on the amount of excess generation EDCs must purchase and the amount default service customers must pay for, at above-market rates.

We stress that this limit on net metered customer-generator systems in no way limits the size of alternative energy systems proposed to be built by any person or entity seeking to interconnect that facility with the electric grid and to sell its power to any willing buyer, including the wholesale energy market. We note that there are other Federal laws and Commission regulations that are designed to promote such development, such as the Public Utility Regulatory Policies Act of 1978, 16 U.S.C.A. § 824a-3 and the Commission's regulations at 52 Pa. Code §§ 57.31-57.39.

d. Historical Usage

i. Existing Service Locations

Comments opposing the 60 month timeframe to calculate the annual electric consumption for existing service locations were received from PECO and EAP. PECO believes that 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 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. PECO ANoFR Comments at 8.

EAP requests that the Commission reconsider its proposal to allow a customer with existing service locations to apply any 12 consecutive month period of electric usage data occurring within the last 60 months to determine its future annual electric consumption for purposes of net metering. EAP asserts that this window provides an excessive amount of discretion to the customer-generator to pick the highest-usage months. EAP recommends reducing this window to 24 or 36 months to account for any outlier usage or weather-dependent usage years. EAP ANoFR Comments at 4.

ii. Disposition

The Commission is not convinced that reducing the timeframe to calculate annual consumption for existing service location accounts from 60 months to 24 or 36 months would provide a better balance or appropriately address outdated information. We recognize that customer load is affected by several variables, such as weather and economic activity and find that 60 months of historical data will adequately capture the effects of such variables and give a more reasonable indicator of future load. Accordingly, the provision in Section 75.13(a)(3)(I) in regards to the 60 month timeframe

to calculate the annual electric consumption for existing service locations is adopted as proposed in the ANoFR.

iii. New Service Locations

PES and PECO submitted comments concerning the annual electric consumption estimates for new service locations. PES asserts that there should be clarity regarding what is acceptable documentation for expected additional electrical load of a building, as in the case of new construction, or a building expansion. PES recommends additional clarity regarding the standard measurement for calculating the annual building consumption. PES ANoFR Comments at 2.

PECO supports the annual consumption estimates for new locations based on building type, size and anticipated usage of electric equipment and fixtures for commercial/industrial customers due to the high degree of variability in the way businesses operate and use energy. For residential customers, PECO believes that 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. PECO recommends that the proposed regulation be revised to specify that: 1) the consumption estimate for commercial/industrial customers 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 be based on the home size and the primary heating source. 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. PECO ANoFR Comments at 8-9.

iv. Disposition

The Commission finds that PECO's request to revise the annual consumption estimates for residential customers is not necessary, as the proposed language indicates anticipated usage of electric equipment, which takes into consideration the primary heating source of the property. Regarding PES' recommendation that standard measurements for calculating the annual building consumption for new service locations be provided in the regulation, we decline to set a specific standard at this time as no commentator, including PES, suggested an appropriate standard that applies to all situations. Accordingly, we adopt the provision in Section 75.13(a)(3)(II) in regards to determining the annual electric consumption for new service locations as proposed in the ANoFR.

e. Application of Rule to New Systems

Comments relative to the 200% size limitation that applies to any interconnection application for a new alternative energy system or expansion of an existing alternative energy system submitted 180 days after the effective date of this rulemaking were received from PECO and PPL. In its comments, PECO states that the ANoFR carved out an exception to the system size limitation for existing systems and those currently under development. PECO believes that the proposed exception is reasonable and should be adopted. PECO ANoFR Comments at 6-7.

PPL recommends that any alternative energy systems that have been approved for net metering by an EDC should be exempt from the new regulations proposed in the ANoFR and permitted to remain on net metering. PPL, however, requests that the Commission reconsider its position on grandfathering facilities that have not been approved for net metering. PPL submits that grandfathering customers that apply within 180 days from the date of the revised regulations become final will create a rush of

applications from prospective developers to beat the revised regulations deadline. PPL ANoFR Comments at 15-16.

i. Disposition

In regards to PPL's comments, Section 75.13(a)(3)(III) addresses the stakeholders' concern with respect to the 200% size limitation impact on existing customer-generators or those in development. The proposed provision clearly indicates the Commission's intent that the size limitation not apply to existing customer-generators and that systems currently in development be excluded from the 200% size limitation provided the customer-generator submits an interconnection application within 180 days of the date this provision becomes effective. We understand PPL's concern that there might be a surge of interconnection applications within the 180-day period; we, however, find that any potential rush of applications to beat the revised regulations would be unavoidable regardless of the time frame adopted. Accordingly, we adopt this provision in Section 75.13(a)(3)(III) as proposed in the ANoFR.

f. Exception to 200% Limit

Several comments were received in regards to the exception to the 200% size limitation for alternative energy systems used to comply with the Department's Pennsylvania Chesapeake Watershed Implementation Plan or as an integral element for compliance with the Nutrient Management Act. TeamAg Inc., State Representative Robert W. Godshall, Brubaker Farms, DEP, and several other parties stated that the use of the word *"may"* leaves room for doubt. The commentators requested that the word *"may"* be replaced with *"shall"* in order to improve clarity. These commentators also indicated other suggested changes to the language in this paragraph including replacing *"is used to comply"* with *"complies*," removing the word *"integral"* and replacing *"for compliance"* with *"of a farm's approved Nutrient Management Plan in compliance*." Team Ag Inc. ANoFR Comments at 1, State Representative Robert W. Godshall ANoFR

Comments in a letter dated 5/26/15, Brubaker Farms ANoFR Comments in a letter dated 5/25/15 at 2-3, DEP ANoFR Comments at 3.

Many stakeholders, such as PSG, the Milk Producers, and Land O'Lakes feel that the Commission should recognize the benefits of farm anaerobic digester installations and exempt them from any negative changes to the net metering rules. PSG ANoFR Comments in a letter dated 5/21/15, the Milk Producers ANoFR Comments at 2, Land O'Lakes ANoFR Comments at 2.

In its comments, PECO agrees that the proposed regulations should not hinder the use of anaerobic digester technologies to advance the Chesapeake Bay restoration plan. PECO, however, 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. PECO requests that the Commission establish a working group to explore the possibility of adopting alternative limits for anaerobic digester technologies. PECO ANoFR Comments at 7.

Arlin Benner submitted comments stating that he is relieved to see that the Commission is seeking a way to prevent farm anaerobic digesters from being lumped in with all the entities that are actually in the business of generating energy. Arlin Benner suggests that no subjective confirmation responsibility be placed in the hands of the DEP, and that DEP's confirmation be based on the permitting and nutrient management requirements already in place for that farm. Arlin Benner ANoFR Comments in a letter dated 5/23/16.

In its comments, the OSBA states that the Commission's order exacerbates the problem faced by default service customers by proposing to exempt certain manure to energy generators from the excess generation limitation entirely. The OSBA has

reviewed the comments and reports from the DEP, PDA and the Chesapeake Bay Commission and can find no quantitative assessment of the economic impact of a restriction on excess net metering generation on the economics of these operations. The OSBA is concerned that the Commission is adopting an exemption based on unsubstantiated claims and that the proposed policy will have some vague, unspecified impact on one particular group of customers. As no evidence has been advanced regarding the impact, the OSBA suggests that the exemption apply only to those customers who can demonstrate that it is economically necessary for the manure to energy generation option to be viable. OSBA ANoFR Comments at 2-3.

i. Disposition

DEP and several other stakeholders recommend that the proposed language from the ANoFR in this section be amended. The Commission agrees to make changes to the language, as we find that the modifications are consistent with the Commission's original intent to exempt farms with anaerobic digester installations as long as the system is consistent with the Department's Pennsylvania Chesapeake Watershed Implementation Plan or is an element of the farm's approved nutrient management plan. Specifically, we agree to the following language changes: 1) Replace "may not" with "does not"; 2) Replace "is used to comply" with "complies"; 3) Delete the word "integral"; and 4) Replace the phrase "for compliance with" with "of a farm's approved nutrient management plan in compliance with." We decline to adopt PECO's proposal to further study this issue through a working group as it would only serve to delay these regulations.

Regarding OSBA's concerns, the Commission finds that limiting the exception to systems that comply with the Chesapeake Watershed Implementation Plan or the Nutrient Management Act appropriately limits the size of such systems and the number of systems that would exceed the 200% limit. We find it significant that such systems are sized to deal only with the waste stream produced by the owner's operation, which limits the

maximum size of the system and the amount of excess generation, and that such a limit demonstrates that the system cannot be scaled to operate as a merchant generator utility. While this will result in the system owner receiving above market rates for that generation, we find that this narrow exception is appropriate to further the public's interest in clean water.

Regarding concerns raised about DEP's role, we note that DEP is the responsible agency for implementing the Chesapeake Watershed Implementation Plan in accordance with the Clean Water Act. In addition, DEP provides technical and administrative assistance to the State Conservation Commission to implement the Nutrient Management Act. The intent of this regulation is simply to have DEP provide confirmation of information DEP would already have on hand regarding its prior determinations related to the Chesapeake Watershed Implementation Plan and the Nutrient Management Act. For these reasons, we adopt the language in Section 75.13(a)(3)(IV) as amended and set forth in Annex A.

g. Residential Service Limit

The fourth, fifth and sixth conditions proposed in the NoPR under section § 75.13(a) simply require that the customer-generator's alternative energy system cannot exceed the nameplate capacity limits, by rate class, as 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 200 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.

Stakeholders did not comment on the proposed changes in the NoPR regarding the fifth and sixth conditions. However, several parties provided comments to the ANoFR

regarding the fourth condition. In this rulemaking, Section § 75.13(a)(4) refers to limiting the nameplate capacity for residential service locations to 50 kilowatts.

TeamAg Inc., State Representative Robert W. Godshall, Brubaker Farms, PDA, PDMP and several other parties stated that many dairy farms in Pennsylvania receive their electricity as residential service and these farms with residential service accounts would be excluded from the benefits of net metering with this current language. Commentators suggested adding *"unless the service is for a normal agricultural operation as defined in the Pennsylvania Right to Farm Act"* to the end of section § 75.13(a)(4). TeamAg Inc. ANoFR Comments at 2, State Representative Robert W. Godshall ANoFR Comments in a letter dated 5/26/15, Brubaker Farms ANoFR Comments at 3, PDA ANoFR Comments at 2, PDMP ANoFR Comments at 2.

Oak Hill Farms stated that they operate a 40 kilowatt anaerobic digester on a residential rate with PPL. If they accepted the maximum amount of food waste allowed by DEP, electric production would double to roughly 64 to 80 kilowatts per hour. Oak Hill Farms asserts that limiting farms with residential service to 50 kilowatts is not a policy that will encourage smaller farms to build digester projects. Oak Hill Farms ANoFR Comments at 1.

i. Disposition

As it is currently written in the AEPS Act, a customer-generator system cannot exceed the nameplate capacity limit of 50 kilowatts at residential service locations. The Commission does not have the authority to set a limit greater than the statutory limit. We note however, that adding a larger anaerobic digester will typically convert the service from a residential service rate to a non-residential service rate, thus increasing the statutory size limitation to three megawatts and resolving the concerns raised.

Accordingly, we adopt the language in Section § 75.13(a)(4) as proposed in the NoPR and subsequently set forth in the ANoFR.

h. Other Service Location Limits

In the ANoFR, Sections § 75.13(a)(5) and (6) were combined. The conditions refer to limiting the nameplate capacity for other customer service locations to three megawatts, except when the alternative energy system has a nameplate capacity not larger than five megawatts and meets the conditions in section § 75.16 (relating to large customer-generators). No comments were received. Accordingly, we adopt the language in Section § 75.13(a)(5) and (6) as proposed in the ANoFR.

i. Commission Approval of 500 Kilowatt Systems

Finally, in the seventh condition proposed in the NoPR under section 75.13(a), we 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 proposed. We noted that this approval process will ensure uniform application of the net metering rules throughout the Commonwealth. We noted 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 further noted 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 noted 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.

Comments supporting the requirement that all alternative energy systems with a nameplate capacity of 500 kilowatts or greater obtain Commission approval were received from Duquesne and PPL. Duquesne NoPR Comments at 3-4, PPL NoPR

Comments at 13. PPL states that unlike smaller-sized alternative energy systems, which are much easier for the EDC to determine whether the customer qualifies as a customer-generator eligible for net metering, PPL believes that alternative energy systems sized at 500 kilowatts and above often require significant resources and time to determine whether they qualify as a customer-generator or are a merchant generator. Furthermore, PPL believes that the Commission's review will ensure that these larger-sized alternative energy systems are treated uniformly and consistently throughout the Commonwealth, which will be a significant benefit to the owners of larger-sized alternative energy systems operating in multiple service territories. Finally, PPL believes that this condition will help ensure that customer-generators whose systems are above three megawatts properly make their systems available to operate in parallel with the electric utility during grid emergencies. PPL NoPR Comments at 13.

Comments opposing the requirement were received from, DCIDA, LVA, and others. DCIDA NoPR Comments at 13-14, LVA NoPR Comments at 1. DCIDA avers that the need for this costly burden is not clear. DCIDA states that the Commission expresses the need for uniform application of the net metering rules throughout the Commonwealth, but notes that it will only review and approve a relatively small number of such applications. DCIDA asserts that nothing explains why review and approval of only the largest alternative energy systems will ensure that the rules are uniformly applied to all customer-generators and alternative energy systems in the Commonwealth. That being said, DCIDA states that there is little for the Commission to actually approve. DCIDA asserts that in the normal course of action, the Commission does not review applications to begin service and there is nothing in the Act which suggests that the Commission should be reviewing the applications. DCIDA also asserts that there is simply no basis for the Commission to deny net metering to a customer-generator and alternative energy system that satisfies the statutory eligibility criteria. DCIDA argues that under the AEPS Act and the Public Utility Code, the Commission's role is to ensure

that the EDC does not violate the customer-generators' statutory right to use net metering and not to grant or deny the statutory right of net metering to any customer-generator. DCIDA NoPR comments at 13-14.

In its comments, the IRRC notes that the Act sets forth criteria for alternative energy systems eligibility, but it does not require approval by the Commission. The IRRC requests clarification on what is the Commission's statutory authority for this provision as it relates to systems of this size. IRRC NoPR Comments at 6.

The seventh condition proposed in the NoPR under section 75.13(a), is listed as the sixth condition in the ANoFR. Only minor language changes were proposed in the ANoFR.

Comments to the ANoFR supporting Commission approval to net meter for all alternative energy systems with a nameplate capacity of 500 kilowatts or greater were received from PECO and EAP. PECO ANoFR Comments at 9-10, EAP ANoFR Comments at 4-5.

i. Disposition

In response to DCIDA comments, the Commission finds that this approval process ensures uniform and consistent application of the net metering rules throughout the Commonwealth and that administrative efforts and costs will be minimal due to the small number of such systems applying for net metering in a year. We stress that the Commission's review is simply to ensure that those entities that claim to meet the definition of customer-generator do in fact meet that definition, as expressed in the AEPS Act and the Commission's regulations. In addition, the Commission's review will ensure that the virtual meter aggregation provisions in the AEPS Act and the Commission's regulations are complied with.

In response to IRRC's request for clarification of the Commission's authority to review these net metering applications, and DCIDA's assertion that the Commission has no such authority, we point out that, as previously stated, the AEPS Act specifically gave this Commission the responsibility to carry out the responsibilities delineated within the AEPS Act. *See* 73 P.S. § 1648.7. Net metering is established, defined and delineated in the AEPS Act and is one of many items that the Commission has the responsibility, given by the General Assembly, to carry out. Furthermore, the AEPS Act specifically required the Commission to "develop technical and net metering interconnection rules for customer-generators intending to operate renewable onsite generators in parallel with the electric utility grid...." 73 P.S. § 1648.5.

Significantly, net metering involves the rate that net metering customer-generators receive for not only the demand for energy they offset and net out each month, but the rate for any excess remaining at the end of the year, which is paid for by other customers. As we noted above, the establishment of such rates and the public utility tariffs that not only contain these rates, but also the net metering and interconnection service provisions, falls squarely within the Commission's authority pursuant to the Public Utility Code. *See* 66 Pa.C.S. §§ 1301-1318, 2807. The Commission's authority is further demonstrated by its promulgation of the current net metering rules. *See* 52 Pa. Code §§ 75.11-75.15, 75.21, 75.22, 75.31-75.40, 75.51. Indeed, based on both the AEPS Act and the Public Utility Code, the Commission is the only agency given responsibility to carry out and enforce the net metering provisions. For these reasons, language proposed in Section 75.13(a)(6) referencing Commission approval to net meter for all alternative energy systems with a nameplate capacity of 500 kilowatts or greater is adopted as proposed in the ANoFR.

2. Section 75.13(b)

As noted above, we moved the reference to EGSs offering net metering to subsection (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.

Comments supporting the clarification to this section proposed in the NoPR and ANoFR were received from PPL. PPL NoPR Comments at 14, PPL ANoFR Comments at 16-17. No opposing comments were received to Section 75.13(b). Accordingly, we adopt the proposed language clarifying 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.

3. Section 75.13(c)

No language changes were proposed in the NoPR to previous subsection (b), re-lettered as subsection (c). Nevertheless, comments were received from RESA suggesting that specific operational protocols be added to the language. RESA recommends adding that the tariff shall require that the EDC's electronic data interchange transactions convey to the customer's EGS, in a timely manner, a net metered customer's actual net consumption information. RESA suggests that the tariff shall also require that electronic data interchange transactions identify all net metered customers. In addition, RESA suggests that each EDC's wholesale settlement reporting transactions for net metered customers reflect the customer's actual net consumption information. RESA states that

inclusion of these specific operational protocols is important to ensure that EGSs wishing to offer net metering to their customers have timely and necessary access to information about the customer to facilitate net metering. RESA NoPR Comments at 2-3.

In response to RESA's comments, the Commission finds that this suggestion is beyond the scope of the current rulemaking and requires further investigation and review. Accordingly, the Commission declines to adopt RESA's proposal.

4. 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.

a. Comments

Comments supporting the clarification to this section proposed in the NoPR were received from PPL and FirstEnergy. FirstEnergy, however, requests modifications to the language. PPL NoPR Comments at 14, FirstEnergy NoPR Comments at 6. In its comments, FirstEnergy states that given the statutory possibility of a non-EDC serving as a DSP, it makes sense to add "DSP" to this section of the proposed regulation. FirstEnergy, however, asserts that the language as drafted is not entirely clear as to the obligations of the EDC in contrast to the obligations of the DSP. Specifically, FirstEnergy avers that a question remains as to which of those entities would be responsible for providing what specific credits to a customer-generator in the event that the day comes where the DSP is not the EDC. FirstEnergy requests modifications to clarify the Commission's intent on this point. FirstEnergy NoPR Comments at 6.

b. Disposition

The Commission declines to adopt FirstEnergy's suggested language as it fails to address the situation where the EDC is acting as the DSP. The language suggested by FirstEnergy states as follows: "An EDC shall credit a customer-generator at the EDC's unbundled distribution kWh rate and the DSP, *where it differs from the EDC*, shall credit a customer-generator at the full generation and market based transmission kWh rate…." (emphasis added). The phrase, "the DSP, where it differs from the EDC," suggested by FirstEnergy, would make this section applicable only to situations where the EDC is not acting as the DSP, making the regulation less clear regarding situations where the EDC is acting as the DSP. The Commission finds that the language, as proposed, and read in conjunction with the other subsections, is clear in that the EDC and DSP are only responsible for the portion of the unbundled service(s) they provide. An EDC that is not providing generation and transmission services as the DSP is not required to provide credits for those services to the customer-generator, which will be provided by the entity acting as the DSP. Vice versa, when an EDC is acting as the DSP, it would be required, as the EDC providing distribution services and DSP, providing generation and transmission services, to provide a credit for all three services.

We will, however, add language clarifying that the net metering credits apply to kilowatt-hour charges. We agree with PPL that a customer-generator is responsible for the customer charge, demand charge, and applicable riders' charges under the applicable rate schedule. *See* PPL NoPR Comments at 17-18, PPL ANoFR Comments at 22-25. We again note that this does not change the original intent of the regulations, but simply provides more clarity. Accordingly, we adopt the language in this section as proposed in the NoPR and as modified in Annex A.

5. 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; they 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 (PTC) rate. In addition, we stated that the DSP is to use a weighted average of the PTC rate based on the rate in effect when the excess generation was actually delivered. This was intended to compensate the customer-generator in a manner that more accurately represents the value of the excess generation.

a. Comments

Comments supporting the clarification to this section proposed in the NoPR were received from the SEF, FirstEnergy, and EAP. SEF NoPR Comments at 2, FirstEnergy NoPR Comments at 6-7, EAP NoPR Comments at 5. FirstEnergy believes that this change is consistent with the legislation, provides clarity to market participants, and is largely consistent with existing practices. FirstEnergy notes, however, that it recently spent significant time and capital to automate the process by which customer-generators are compensated for excess generation, with the automated process fully implemented in August 2013. As a result, FirstEnergy states that it currently calculates the PTC charges by applying the current PTC pricing to the customer's total generated energy, or "metered outflow." FirstEnergy states that its system accumulates both the generated energy and the monthly PTC charges on that generated energy throughout the year. When the customer is netted out and compensated each year end, the system calculates the weighted average PTC as being equal to the accumulated PTC charge on generated energy, divided by the accumulated generated kWh. The credit is then calculated by applying a weighted average PTC value to any excess generation remaining. Due to the recent automation of

the process, and given that the average cash out values are not significant, FirstEnergy requests that their process be determined to be compliant with the regulations. FirstEnergy NoPR Comments at 6-7.

EAP generally supports the proposed changes to 52 Pa. Code § 75.13(e) regarding excess generation calculation at the end of the year and the manner in which compensation for the excess is to be computed. EAP appreciates the clarification that the EDC/DSP is to use a weighted average of the PTC rate based on the rate in effect when the excess generation was delivered. EAP notes that this methodology more accurately reflects the true value of the excess. EAP, however, requests further clarification on this matter relative to the exact methodology or formula that is to be used. EAP recommends that whatever the method is, it should be both easily understandable to the net metering customer, uniform across EDCs/DSPs in the state and cost-effective to implement. EAP NoPR Comments at 5.

Duquesne agrees with the provision to use the weighted average of the PTC rate for compensation of excess kilowatt hours at the end of the year. Duquesne believes that each EDC should address credits and compensation through their individual tariffs. Duquesne ANoFR Comments at 3.

Comments opposing the clarification to this section proposed in the NoPR were received from PPL and OSBA. PPL NoPR Comments at 14-17, and OSBA NoPR Comments at 2-3. In its comments, PPL notes that cashing out using the weighted average of the PTC based on the rate in effect when excess generation was actually delivered is a new requirement that is not currently contemplated in the plain language of the net metering regulations. Although the Commission discussed using a weighted average generation and transmission rate to calculate a customer-generator's yearend compensation in a prior rulemaking (Final Omitted Rulemaking Order July 2, 2008), the

applicable regulations in this section provide that a customer-generator's yearend compensation should be calculated at the PTC. PPL appreciates the Commission's efforts to clarify the yearend compensation to customer-generators, but submits that there are additional and critical considerations that must be taken into account before such a proposal can be implemented. PPL notes that the use of a weighted average generation and transmission rate will require individual price-to-compare rates for each individual customer-generator, asserting that not only will this be complicated, time consuming, and expensive, it will cause massive confusion for customers. If the proposed approach is adopted, PPL recommends that the Commission consider the time and cost involved to implement the proposed weighted average annual cash out method. Further, additional costs will be necessary to upgrade PPL's billing system to accommodate the weighted average annual cash out method. PPL NoPR Comments at 14-17, PPL ANoFR Comments at 17-21.

PPL also notes that not all alternative energy systems produce excess generation during the same periods, which could have significant impact on net metering customers on time of use (TOU) rates. Therefore, PPL recommends that the Commission establish a pre-defined weighted average for TOU rates based upon the generation type. As an alternative to the use of a weighted average generation and transmission rate to calculate a customer-generator's year-end compensation, PPL recommends that the Commission consider adopting a straight PTC average for the year. PPL asserts that using a straight PTC average will reduce customer confusion, complexity, and the time and resources that would otherwise be required to implement the weighted average proposal. PPL recommends that the Commission adopt a reasonable time period for EDCs to design, implement, and test the modifications to their respective information technology systems necessary to implement the new weighted methodology, and that the Commission consider the cost involved to implement the proposed weighted average annual cash out method. PPL NoPR Comments at 14-17, PPL ANoFR Comments at 17-21.

OSBA states that EDCs and DSPs are obligated to cash out any annual excess net generation at the end of the year. This excess generation becomes part of the default service supply, as it implicitly offsets the purchases that the DSP must make. OSBA notes, however, that this type of default service supply has a negative impact on regular default service customers. OSBA notes that the net generator is compensated at the full PTC, which includes transmission service charges, but it is unclear that the customer-generator provides transmission cost benefits that are commensurate with the credits it receives. OSBA asserts that it is equally unclear that, to the extent that any transmission cost offsets are realized, those benefits are assigned only to the customer class that is paying for the net generation. OSBA NoPR Comments at 2-3. The OSBA generally concludes that the payment for net generation should reflect the timing of that net generation. However, it must be recognized that any net generation involves periods of 'exports' to the grid and 'imports' to the grid. While the proposed language makes it clear that it is the Commission's intent to use a more representative price-to-compare, it is unclear how this will work in practice. OSBA ANoFR Comments at 4-5.

IRRC notes that a commentator asked for clarification on the exact methodology to make the required determinations, and another stated that the proposed language will be time consuming and costly to implement. The IRRC asks the Commission to work with the regulated community to develop a more precise and less costly alternative to the proposed language. IRRC NoPR Comments at 6.

b. Disposition

Upon review of the comments, the Commission recognizes that the applicable rates for generation and transmission to be credited and paid to customer-generators for excess generation varies by rate class and, in some instances, between customers within a rate class. The Commission also recognizes the potential significant costs associated with

establishing and automating the process of computing the amount to be paid to each customer-generator for the excess generation at the end of the year. While some parties have requested that we establish specific formulae to compute the amount to be paid for excess generation, no party provided a formula that would apply to all rate designs or customer service classes. While our intent was to provide clarity to all EDCs and customer-generators regarding how the rate for excess generation is to be determined, we find that the proposed language created more confusion, as it results in varied outcomes based on the particular rate, such as time-of-use and real-time price plans, and multiple interpretations based on the rate.

For these reasons, we will delete the proposed sentence that referenced the weighted average of the PTC rate. We will continue our current practice of reviewing and approving each EDC's tariff provisions addressing this compensation during base rate and default service rate proceedings that provide an opportunity for all effected stakeholders to be heard and to propose alternatives. We will, however, retain the clarifying language regarding what constitutes year-end excess generation and the reference to DSP.

6. 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.

a. Comments

Comments supporting the clarification to this section proposed in the NoPR and ANoFR were received from PPL. PPL, however, recommends that the Commission consider adding clarifying language explicitly stating that the "customer-generator is responsible for the customer charge, demand charge, and applicable riders charges under the applicable Rate Schedule." PPL NoPR Comments at 17-18, PPL ANoFR Comments at 22-25.

b. Disposition

In response to PPL's request for clarification, the Commission agrees that a customer-generator is responsible for the customer charge, demand charge, and applicable riders charges under the applicable rate schedule. Accordingly, we have added further

clarifying language to confirm that the distribution kilowatt-hour rate credit shall be applied against kilowatt-hour distribution usage charges. Accordingly, we adopt the language in this section as proposed in the NoPR and as modified in Annex A.

7. 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.

PPL provided comments supporting the clarification to this section proposed in the NoPR and ANoFR. PPL NoPR comments at 18, PPL ANoFR comments at 25. No opposing comments were received to Section 75.13 (j). Accordingly, we adopt the proposed language that references default service and the default service rate.

8. 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.

a. Comments

Comments supporting the clarification to this section proposed in the NoPR were received from PPL and PECO. PPL supports and appreciates the Commission's efforts to clarify that EDCs are permitted to impose fees or charges for providing virtual meter aggregation. PPL believes that imposing the costs to automate the virtual meter aggregation billing system on the limited number of existing virtual meter aggregating customers would erode any benefits that could potentially be realized by those customers. PPL submits that, to the extent that EDCs are required to automate virtual meter aggregation and/or provide additional data regarding the host and satellite accounts, EDCs should be permitted to fully recover the costs incurred, subject to review in an appropriate Commission proceeding. PPL recommends that the Commission provide additional guidance on the "incremental costs" that should be directly charged to virtual meter aggregating customers and those that should be recovered through base rates. PPL NoPR Comments at 18-20.

In its comments, PECO states the extent to which the proposed section 75.13(k) could be utilized to develop fair and reasonable charges for net metering customers should be adequately and fully considered. Accordingly, the general nature and structure of future net metering charges should be addressed as part of the separate, comprehensive review of net metering and interconnection policies and related AEPS issues. PECO NoPR Comments at 8.

Many stakeholders oppose the proposed NoPR clarification to this section indicating that the revised language would authorize the Commission to *impose any fee* at any time at its discretion. Larry Moyer, SEF, SRECTrade, MAREA, Vincent Cahill & Claire Hunter and other numerous stakeholders filed related comments. Larry Moyer Part

B NoPR Comments at 3-4, SEF NoPR Comments at 6-7, SRECTrade NoPR Comments at 2-3, MAREA NoPR Comments at 1, Vincent Cahill & Claire Hunter NoPR Comments at 3-4.

The SEF opposes the revision to this section because it could create a venue for EDCs to charge net metering customers who do not utilize virtual meter aggregation. The language proposed by the Commission is overly broad and could be interpreted to include charging all net metering customers a fee. Instead, SEF proposes to modify the section to make it clear that any additional charge would only apply to customer-generators that utilize virtual meter aggregation and only to cover reasonable administrative costs. SEF NoPR Comments at 6-7.

SRECTrade opposes the revisions because the proposed language is overly broad and could be interpreted to include charging a minimum bill to all net metering customers. Accordingly, SRECTrade urges that the Commission rely on the original intention of §75.14(e), and restrict the applicability of §75.13(k) to the fees permitted under §75.14(e). SRECTrade NoPR Comments at 2-3. MAREA urges that we withdraw the changes to 75.13(k) giving the Commission authority to approve utility company requests to charge net metered customers special fees. MAREA NoPR Comments at 1.

IRRC comments state that this subsection would allow for the imposition of a fee or charge and it raises the following additional concerns. First, how will this fee be calculated and what factors would the Commission consider when allowing such a charge or fee? Second, would the charge or fee be limited to customer-generators, or could it be imposed on any customer of an EDC or DSP? Third, will the proposed charge or fee be exclusively tied to section 75.14(e)? If this provision remains in the final rulemaking, the IRRC recommends that the regulation specifically cite that section and delete the phrase "under this chapter." The IRRC also questions under what circumstances the

Commission may, by order, impose a charge or fee and asks the Commission to quantify how much of a cost the charges or fees will impose on the regulated community. Finally, the IRRC questions the reasonableness of a provision that would stifle the development of alternative energy and whether the result is consistent with the intent of the Act. IRRC NoPR Comments at 7.

Comments opposing the clarification to this section proposed in the ANoFR were received from the DEP, PennFuture Joint Commentators, LWV, PA IPL, SolarCity and many other stakeholders. DEP ANoFR Comments at 3-4, PennFuture Joint Commentators ANoFR Comments at 4-5, LWV ANoFR Comments at 1, PA IPL ANoFR Comments at 2, SolarCity ANoFR Comments at 1.

The DEP states that the proposed regulation amends the language prohibiting EDCs from charging fees or other types of charges for net metering by adding an exception for fees or charges "specifically authorized by this chapter or by order of the Commission." The preamble of the proposed regulation explains that this language was added in order to resolve an inconsistency in the regulations. Specifically, in § 75.14(e), the PUC permits EDCs to charge fees for incremental expenses related to the processing of an account in order to provide virtual meter aggregation. While the DEP agrees that it is appropriate for customer-generators to pay for the costs related to virtual meter aggregation as outlined in the ANoFR, inclusion of the phrase "or by order of the Commission" is unnecessary and unsupported by statutory authority. The inconsistency identified by the PUC is fully resolved by the inclusion of the phrase "specifically authorized by this chapter" which clearly would include the fees in § 75.14(e). A blanket authorization to impose fees as the PUC may see fit goes far further than needed to address the inconsistency, and opens the door for the future imposition of fees not intended under the AEPS Act. As with the virtual meter aggregation fees, any future

additional fees should be properly vetted within the context of the Regulatory Review Act, and consistent with the intent of the Act. DEP ANoFR Comments at 3-4.

The Joint Commentators oppose the changes in this section and believe that the actual proposed language allows fees to be charged to any net-metered customer, not just customers whose accounts are aggregated through virtual meter aggregation. They further state that the proposed language does not restrict the fees to administrative costs of aggregating and billing virtual meter aggregation accounts. In fact, there are no standards or reasons given as to when and why the Commission could order an additional fee. The Joint Commentators feel that the language needs to be rewritten so that it is firmly within the limits of the Act. The new language should clearly apply only to the administrative costs of billing virtual meter aggregation systems. Joint Commentators ANoFR Comments at 4-5.

PA IPL opposes the changes in §75.13(k) that would give the Commission authority to allow utilities to charge any new fees that are not also levied upon non-net metered customers. PA IPL believes levying these fees would violate the AEPS guarantee that net metered customers receive the full retail rate for all generation of their solar installation up to their annual usage. Moreover, the proposed change fails to provide any basis for determining this fee. If there is to be a fee, it should be based on a full cost of service study that evaluates both the costs and the benefits of each specific net metered system. PA IPL ANoFR Comments at 2.

b. Disposition

In response to concerns raised by IRRC and other parties, we note that in addition to making this section consistent with § 75.14(e), the regulations also permit interconnection fees that are set by the Commission. These fees are addressed in the existing regulations at 52 Pa. Code §§ 75.21, 75.22, 75.31-75.40. Specifically, 52 Pa.

Code § 75.33 (Fees and forms) states that "[t]he Commission will determine the appropriate interconnection fees for Levels 1, 2, 3, and 4." The Commission establishes these fees through orders based on filings submitted by the EDCs, which give all interested parties an opportunity to be heard and an evidentiary hearing if needed. *See* Commission Policy Statement at 52 Pa. Code § 69.2102 (relating to the purpose of interconnection application fees). We also note that any fee an EDC seeks to impose for the costs associated with virtual meter aggregation must also receive Commission review and approval through a process that gives notice to interested parties and gives interested parties an opportunity to be heard. The Commission will rule on such fee petitions through an order adopted at a public meeting. Thus, the proposed language simply makes clear what § 75.14(e) and § 75.33 already established and removes the inconsistency.

Regarding the possibility of other fees, the Commission has full ratemaking authority related to electric service by an electric public utility. *See* 66 Pa.C.S. § 1301. The Commission has a well-established process for setting electric public utility rates that affords all interested parties ample notice and opportunity to be heard. *See* 66 Pa.C.S. 1308. Through these ratemaking proceedings, cost of service studies, as suggested by PA IPL, may reveal unjust and unreasonable intra- or inter-class subsidies that require changes in the rates or fees imposed on specific customer classes. *See, e.g., Lloyd v. Pa. PUC*, 904 A.2d 1010 (Pa. Cmwlth. 2006) (discussing cost of service). The Commission has had such authority since its inception. Any rates, costs or fees approved by the Commission are based on the evidence presented during appropriate proceedings, such as rate case proceedings. See 66 Pa. C.S. §§ 1308-1309. Thus the Commission cannot, at this time, determine when such rates, costs and fees will be imposed or their impact on any particular customer class or customer. The Commission is in no way setting or establishing any new rates or fees with this rulemaking.

The language change proposed simply puts all parties on notice of the possibility of fees. Again, as stressed throughout this process, the purpose of many of these changes is to provide clarity and to fully inform all stakeholders of these and other regulatory issues. No party has cited to any restriction in the AEPS Act that preempts or in any way restricts the Commission's ratemaking authority. As always, when setting rates and fees, the Commission will provide all interested parties ample notice and opportunity to be heard regarding such rates and fees. Accordingly, we find that the proposed language for 75.13(k) is appropriate and fully within the Commission's authority and adopt the language as proposed.

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.[10] 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:

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[10] 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.

> 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 environment 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.[11] The language in the

[11] *See* P.L. 114, No. 35 of 2007.

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 meter aggregation 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 a meter account owned and operated by an entirely different customer at another location within the two mile limit. The Commission proposed revisions in the NoPR to Sections 75.12 and 75.14 to clarify the acceptable scope of virtual meter aggregation.

a. NoPR Comments

Comments supporting the changes proposed in the NoPR to the definition of virtual meter aggregation in Section 75.12 were received from FirstEnergy. FirstEnergy supports the Commission's proposed changes to the definition, but believes that the definition would also benefit from further clarification of what qualifies for virtual meter aggregation, as there is often confusion in application of this term as to how broadly the legislature intended this term to be applied. FirstEnergy suggests that for clarification purposes it also be specified that retail electric accounts in the name of different legal entities or customers should not be included in the virtual meter aggregation of a customer-generator. FirstEnergy NoPR Comments at 4-5 and 7-8.

Comments opposing the changes proposed in the NoPR to the definition of virtual meter aggregation in Section 75.12 were received from numerous parties. PSU feels that the proposed amendment requiring measurable electric load independent of the alternative

energy systems and the proposed requirement that a customer-generator have electric load behind the meter and point of interconnection, will severely curtail the deployment of alternative energy systems by customer-generators that have multiple varied, non-contiguous tracts of property. PSU asserts that this frustrates the fundamental intent of the Act. PSU NoPR Comments at 7-9. Citizen Power disagrees with the proposed modification that requires that each location must have measurable electric load, independent of the alternative energy system, in order to be aggregated. Citizen Power NoPR Comments at 2-3.

In its comments, PPL states that it generally supports the proposed changes. However, PPL believes the requirement that virtual meter aggregation systems have independent load needs further clarification. PPL recommends that the requirement for independent load be modified to make it clear that it applies to the satellite account (e.g. the primary account for the residence or building) rather than the host account (e.g. the account for the alternative energy system). PPL believes that applying the requirement for independent load to the host account is entirely inconsistent with the purpose of virtual meter aggregation and would render virtual meter aggregation meaningless. PPL NoPR Comments at 20-21.

The ABC opposes the proposed change to the definition that adds a requirement that all service locations must have separate existing measureable load. This proposed change would prevent appropriate siting for virtual net metered systems, as it requires systems to be installed in close proximity to a customer-generator's existing meters that have a measurable load. These proposed modifications create a new hurdle for project development and limit the potential for additional renewable resources for Pennsylvania. ABC NoPR Comments at 4. The LCCD expresses its concern regarding the application of virtual meter aggregation and states that it is unclear which end-users can be included in the maximum two miles distance from the property that is generating the renewable energy. LCCD NoPR Comments at 1.

b. ANoFR Proposal

In the ANoFR, the Commission proposed language to clarify that the meter accounts to be aggregated must be held by the same person or entity. This clarifying language is to ensure consistency with the AEPS Act requirement that the meters to be virtually aggregated must be on properties owned or leased and operated by one customer-generator and must be located within a single EDC service territory.

c. ANoFR Comments

Comments supporting the changes proposed in the ANoFR to the definition of virtual meter aggregation in Section 75.12 were received from FirstEnergy. FirstEnergy strongly supports this definition and recommends that it be adopted. FirstEnergy ANoFR Comments at 2.

Comments opposing the changes proposed in the ANoFR to the definition of virtual meter aggregation in Section 75.12 were received from several stakeholders, such as Granger, OCA, PA IPL, and many others. Granger states that the changes proposed to Section 75.12 would require each meter of a customer-generator to have measurable load not related to the alternative energy system. Granger feels that the proposed regulations could prevent the use of virtual net metering and would impact the ability to locate alternative energy systems. Granger, therefore, believes that there is little, if any, justification for creating and applying such a restriction on any customer-generator. There are legitimate scenarios where a customer-generator may wish to build a stand-alone, alternative energy system and use virtual net metering to offset that customer-generator's demands at another location. Granger asserts that no reasonable explanation has been presented for prohibiting such arrangements, and no statutory support can be found for an "independent" load requirement for virtual net metering

under the AEPS Act. Granger NoPR Comments at 23-27, Granger ANoFR Comments at 14-15.

In its comments, the OCA states that the ANoFR proposes to modify the definition of virtual meter aggregation in Section 75.12. As compared to the original revision in the NoPR, this definition clarifies that the meter accounts to be aggregated must be held by the same person or entity. The OCA appreciates the clarification, but continues to have concern about the independent load requirement. The wording appears to require independent load at each meter. This may preclude a residential customer from locating solar panels on their property if that location required a separate meter but has no independent load at that location. Requiring load behind each meter location for residential installations could limit the development of residential alternative energy systems. The OCA states that there are many reasons a residential customer-generator may need to locate an alternative energy system at some distance from the home, where the meters that would have the independent load are located. The OCA recommends, for residential installations, that the Commission clarify the requirement of having independent load. OCA NoPR Comments at 5-8, OCA ANoFR Comments at 4-6.

The PA IPL opposes the proposed change in § 75.12 to the definition of virtual meter aggregation that adds a requirement that all service locations must have separate existing measurable load. It should be sufficient that the customer-generator have measurable electric load, not that each meter of the customer-generator have measurable load. This proposed change would prevent appropriate sighting for virtual net metered systems as it requires systems to be installed in proximity to a customer-generator's existing meters that have a measurable load. PA IPL asserts that this violates the AEPS legislation's intent to promote new clean distributed generation. PA IPL ANoFR Comments at 3.

PPL supports the virtual meter aggregation revisions, but again recommends that, for the purposes of virtual meter aggregation only, the requirement for independent load be modified to make it clear that it applies to the satellite accounts(s) (the primary accounts(s) for the residence(s) or building(s)) rather than the host account (the account for the alternative energy system), because there could be no independent load on the host account. PPL notes that this modification, together with the 200% size limitation, will continue to limit the potential for merchant generators to use virtual meter aggregation as a way to circumvent the wholesale electric market and realize retail rate subsidies at retail customers' expense. PPL ANoFR Comments at 27-28.

Additional comments opposing the changes proposed in the ANoFR to the application of virtual meter aggregation were received from many commentators, such as the DEP, and Larry Moyer. DEP ANoFR Comments at 4, Larry Moyer ANoFR Comments at 1-4.

In its comments, the DEP states that under the ANoFR, customer-generators can aggregate generation and load at different locations subject to certain conditions. One of these conditions is that all service locations to be aggregated must have measurable load independent of any alternative energy system. The Commission identifies as a problem "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" and seemingly intends the identification of this issue as a problem to be self-evident. The DEP disagrees. DEP argues that it would not be unreasonable, for example, for a property owner with multiple acres to install solar panels on a remote corner of their property. If it makes more economic sense to interconnect this generation to a nearby distribution line instead of connecting the system back to the customer-generator's meter, that option should remain available to both the customer-generator and the electric distribution company. The result of requiring load

independent of the distributed generation system will add additional costs or disqualify systems unnecessarily. The Commission's proposed limitations requiring that service location accounts be held by the same entity provides an adequate safeguard against the merchant generator concerns related to independent load at the distributed generation site. Ultimately, the intent of the net-metering and virtual metering provisions of the Act is to encourage the installation of distributed alternative energy generation. DEP ANoFR Comments at 4.

Larry Moyer opposes the independent load requirement, claiming that the proposed regulations limit access to virtual meter aggregation. Mr. Moyer states that the proposed change eliminates broad access to virtual meter aggregation as stated in the AEPS Act. He claims that the revisions discriminate against residential customers and favor commercial customers. Larry Moyer ANoFR Comments at 1-4.

d. Disposition

Issues raised regarding what is and is not virtual meter aggregation and whether independent load is required were addressed above in the disposition for changes to § 75.13(a) (Independent Load) at Section B.1.a.ii of this Order. As such, they will not be restated here. The Commission, however, agrees with FirstEnergy that further clarifying language regarding what service locations are and who qualifying account holders are for virtual meter aggregation is needed, and has added language providing the clarification requested by FirstEnergy. Accordingly, we adopt the proposed changes as modified in Annex A.

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.[12] 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 initially proposed 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.

a. NoPR Comments

Comments supporting the changes proposed in the NoPR to the term "year and yearly" as it applies to net metering to the period of time from May 1 through April 30 were received from several stakeholders, such as Robin Alexander, PES, and SEF. Robin Alexander NoPR Comments at 4, PES NoPR Comments at 1, SEF NoPR Comments at 2.

Comments opposing the changes proposed in the NoPR were received from PPL, PECO and EAP. PPL NoPR Comments at 21-22, PECO NoPR Comments at 9-10, EAP NoPR Comments at 3-4. In its comments, PPL recommends a change and states that the proposal appears to be directed primarily towards maximizing the value received by photovoltaic alternative energy systems, which produce the majority of their excess generation between May and August and, in theory, would be able to bank more excess generation at the full retail rate and carry it forward. PPL submits that the proposed change in the yearly period will disassociate the net metering period from the PJM planning period and price-to-compare issuance periods, which run June 1 through May

[12] *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.

31. The proposed change will further complicate its billing systems and needlessly confuse customers. PPL NoPR Comments at 21-22.

PECO disagrees with the proposed changes for several reasons. First, the proposal would misalign the net metering program with existing regulatory and operational frameworks for PJM and implementation of the AEPS Act and default service. Second, the change would likely increase cost-shifting for net metering customers at the expense of other distribution customers. Finally, PECO would have to incur additional costs to implement software changes to accommodate a different net metering calendar. PECO NoPR Comments at 9-10.

In its NoPR comments, the IRRC states that commentators are concerned that the amendment to this definition will impose costs on EDCs that relate to modifications to information technology and billing systems. The IRRC asks the Commission to work with the regulated community to gain a better understanding of how the proposed amendment would be implemented and the corresponding financial implications of such changes. IRRC NoPR Comments at 5.

b. ANoFR Proposal

Consequent to IRRC's request to work with the regulated community, a revision to this section was proposed in the ANoFR and the term "year and yearly" as it applies to net metering was changed to the period of June 1 through May 31.

c. ANoFR Comments

Comments supporting the changes proposed in the ANoFR to the term "year and yearly" as it applies to net metering were received from FirstEnergy, PPL and PECO. In its comments, FirstEnergy supports the alignment of the net metering term year to the PJM planning year. FirstEnergy ANoFR Comments at 2. PPL and PECO strongly

support the change back to the period of time June 1 through May 31. PPL ANoFR Comments at 9, PECO ANoFR Comments at 2.

d. Disposition

The Commission finds that the changes to the definition of year and yearly to the period of time from June 1 through May 31 provides clarity to all interested stakeholders in a manner that does not increase EDC costs borne by ratepayers. Accordingly, we adopt the proposed definition for year and yearly as it applies to net metering to the period of time from June 1 through May 31.

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 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)[13] 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 be part of a microgrid 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 their output to the local utility cannot qualify as customer-generators, as they cannot make their generation available to operate in parallel with local utilities 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. A large distributed generation system may also qualify for

[13] See PJM Agreements/Governing Documents, available at http://www.pjm.com/documents/agreements.aspx.

customer-generator status if it is part of a microgrid and provides 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.

1. NoPR Comments

Comments supporting the changes proposed in the NoPR to this section were received from PPL and PECO. PPL generally supports the proposed changes that address distributed generation systems with a nameplate capacity of greater than three megawatts and up to five megawatts, and to identify the standards that must be met to qualify as a large customer-generator. PPL, however, feels that the definition of grid emergencies needs further clarification. PPL NoPR Comments at 22. PECO supports the proposed changes in this section, but requests clarification regarding the extent to which a system that operates continuously or is powered by wind or solar energy could satisfy the large customer-generator requirement of proposed Section 75.16(b)(3). PECO NoPR Comments at 10.

Comments opposing the changes proposed in the NoPR to this section were received from several stakeholders, such as LCSWA, SRECTrade, DOJ and PJM. LCSWA and DOJ comment that the requirement to limit generation to emergencies called by PJM is, effectively, a limitation on renewable project capacity to less than three megawatts and not a realistic route to large projects. LCSWA NoPR Comments at 2, DOJ NoPR Comments at 2. SRECTrade states that the definition of customer-generator imposes very specific pre-qualifications to the qualification of a customer-generator. SRECTrade argues that while it would certainly be beneficial if such generators *could* serve as a grid support generation resource, it seems onerous to *require* a retail electric customer to serve as a grid support generation resource *in order to be* qualified as a customer-generator. SRECTrade avers that the proposed changes in this section create a conflict between the intention of the definition of customer-generator and these specific,

onerous requirements. SRECTrade asserts that these procedures could impact a customer's net meter eligibility. Therefore, SRECTrade suggests that the Commission adjust the proposed language in section 75.16 to match the intention of the definition of customer-generator, so that customers will not be required to have their system pre-qualified by rigorous RTO procedures *before* they are able to seek qualification by the Commission. SRECTrade NoPR Comments at 3-5.

PJM states in its comments that it supports the Commission's requirement that each distributed generation system be able to support the transmission grid during an emergency. PJM, however, notes that most, if not all, distributed generations systems participating in the Commission's retail net metering program do not satisfy the requirements under PJM's governing agreements to be designated and compensated as generators that may be called upon to respond to grid emergencies. PJM states that the proposed regulations will not result in the distributed generation systems being available to respond to grid emergencies. PJM requests that the Commission adopt a preferred method that it will use to request support from customer-generators during grid emergencies. PJM NoPR Comments at 2-4.

The IRRC notes that commentators believe that it is unrealistic for some renewable energy projects of this size, such as wind and solar, to be available during grid emergencies as required under subsection (b). IRRC requests clarification on how systems that operate continuously or are powered by wind or solar can comply with this provision. Another commentator notes that the provision, as written, would not allow a system to respond during grid emergencies because of governing agreements with RTOs. The IRRC asks the Commission to explain how this section will be implemented and to amend the NoPR accordingly to address these concerns. IRRC NoPR comments at 7.

2. ANoFR Proposal

The Commission recognized IRRC's and other commentators' concerns to the NoPR and proposed changes in the ANoFR to the standards that qualify a distributed generation system with a nameplate capacity above three megawatts and up to five megawatts for customer-generator status by eliminating the requirement that the RTO designate the alternative energy system as a generation resource.

3. ANoFR Comments

PPL submitted comments supporting the changes proposed in the ANoFR to Section 75.16. PPL ANoFR Comments at 28. No opposing comments were received.

4. Disposition

In regards to concerns raised by IRRC and other parties about the ability of intermittent resources to meet the conditions proposed in Section 75.16, we note that it is the language in the AEPS Act that requires these conditions. The Commission is without authority to promulgate regulations that conflict with this language and permit systems that cannot meet these conditions to net meter. The AEPS Act definition for customer-generator states, in part, the following:

> except for customers whose systems are above three megawatts and up to five 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....

73 P.S. § 1648.2 (definition of customer-generator). This definition specifically requires the alternative energy systems to operate in parallel during a grid emergency. Grid emergencies could occur during any time for a multitude of reasons, such as weather, high demand or equipment failures that result in high or low voltage conditions on the

grid. During high voltage conditions, the grid operator must be able to decrease the flow of electricity on the grid by reducing generation until the grid voltage returns to safe levels. During low voltage conditions, the grid operator must be able to either increase generation or decrease customer demand by ramping up generation or calling on demand response resources to reduce demand until the grid voltage returns to safe levels. To meet these AEPS Act requirements, the alternative energy system must be available whenever a grid emergency occurs. If the alternative energy system is unable to respond due to a system design limitation or other contractual obligation, it does not satisfy the requirements contained in the AEPS Act.

Regarding microgrids designed to maintain critical infrastructure, we note that by definition, a microgrid must be able to island itself from the grid and continue to provide power to the customers and facilities connected to that microgrid. If an alternative energy system can demonstrate that it is a distributed resource that supports a microgrid when the microgrid is disconnected from the larger grid, it will qualify as a large customer-generator. Again, this is a requirement imposed by the AEPS Act, not the Commission. In promulgating these regulations, the Commission is providing an avenue for nonutility owners or operators of alternative energy systems to qualify as customer-generators when the alternative energy systems have a nameplate capacity above three megawatts and up to five megawatts as required by the AEPS Act.

Allowing such systems to qualify for net metering when they cannot meet the AEPS Act requirements would be contrary to the plain language of the AEPS Act and beyond the Commission's authority to grant. We again note that while the purpose of the AEPS Act is to promote alternative energy, the General Assembly placed limits on how such systems are to be promoted. The size limitations contained in the definition of customer-generator are such that the Commission cannot contravene. For these reasons we adopt the proposed language as modified in Annex A.

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 200% 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 (TUS) 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 TUS. TUS 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. TUS is to describe in detail its reasons for disapproval of an application. The applicant or the EDC may appeal TUS's determination to the Commission within 20 days after service of notice in accordance with Section 5.44 (relating to petitions for appeal from actions of staff).

In the ANoFR, the Commission shortened the time EDCs have to submit an application with its recommendation to TUS from 20 to 15 days. In addition, TUS now has 10 days, as opposed to 30 days, to review an EDC recommendation to approve a net metering application. Finally, for review of an EDC recommendation to deny a net

metering application, TUS is to issue its determination within 30 days of receipt of the EDC's recommendation or within five days of receipt of an applicant's reply, whichever is earlier.

1. NoPR Comments

Comments supporting the changes proposed in the NoPR to this section were received from PPL, FirstEnergy and EAP. EAP NoPR Comments at 5-6. PPL supports the proposed process, but notes that, if adopted, the interconnection regulations should also be updated and reconciled with the proposed process. PPL NoPR Comments at 22. FirstEnergy also supports the changes to Section 75.17; however, it feels that the process outlined is expected to increase the costs borne by EDC's in processing net metering applications for units in excess of 500 kW. FirstEnergy urges the Commission to increase the fees an EDC may charge for the review of such applications. FirstEnergy NoPR Comments at 8.

Numerous stakeholders, such as PennAg, Sunrise and PECO, submitted comments opposing the changes proposed in the NoPR to the process for obtaining Commission approval of customer-generator status. PennAg urges the Commission to waive the requirement for obtaining Commission approval of customer-generator status with a nameplate capacity of 500 kilowatts or greater for farms. PennAg NoPR Comments at 2. Sunrise opposes the increase of the proposed processing time from 10 days to 20 days for the initial EDC application, followed by an additional 30 days for TUS. Sunrise asserts that adding a minimum of 40 days to this process is nearly certain to doom most large projects. Sunrise NoPR Comments in a letter dated 7/24/15. PECO believes that Section 75.17(b) should be revised so that it provides an adequate review timeframe, consistent with the existing process. In particular, PECO suggests that 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. PECO NoPR Comments at 11.

2. ANoFR Proposal

The Commission acknowledged these concerns and consequently proposed language in the ANoFR that shortened the time EDCs have to submit an application with its recommendation from 20 to 15 days.

3. ANoFR Comments

Comments supporting Commission approval for net metering systems over 500 kilowatts and opposing the shortened EDC review time changes proposed in the ANoFR were received from FirstEnergy, PECO, PPL and Duquesne. FirstEnergy ANoFR Comments at 4-5, PECO ANoFR Comments at 9-10, PPL ANoFR Comments at 28-29, Duquesne ANoFR Comments at 3-4. FirstEnergy notes that it supports the Commissions involvement in the approval of large systems, but it objects to the reduced timeframe. FirstEnergy avers that the revised timeframe does not provide adequate time for an effective review and is inconsistent with the standard interconnection process and creates a direct conflict within the regulations. FirstEnergy further states that requiring an EDC to submit its recommendation to TUS prior to completion of the review is inappropriate. FirstEnergy recommends that all projects over 500 kilowatts be submitted to TUS concurrent to the time they are submitted to the EDC. FirstEnergy proposes that the EDC would wait for TUS to rule on project eligibility prior to a full engineering review. FirstEnergy ANoFR Comments at 4-5.

PECO supports Commission approval to net meter for projects over 500 kilowatts. PECO, however, states that the proposed shortened review time could jeopardize safety and reliability especially with larger projects. PECO recommends adoption of the timeframe proposed in the NoPR. PECO ANoFR Comments at 9-10.

In its comments, the IRRC states that this section establishes the process through which EDCs obtain PUC approval to net meter alternative energy systems with a nameplate capacity of 500 kilowatts or greater, and asks if this process will run simultaneously with the review procedures set forth in subchapter (c), relating to interconnection standards for new customer-generators. The IRRC asks the Commission to ensure this new section does not delay a potential customer-generator's ability to employ a new alternative energy system as quickly as possible. IRRC NoPR Comments at 7.

PPL and Duquesne support Commission approval of customer-generator status for systems with a nameplate capacity of 500 kilowatts or greater; however, they oppose the shortened time period for EDC technical review. PPL ANoFR Comments at 28-29, Duquesne ANoFR Comments at 3-4.

Comments opposing the changes proposed in the ANoFR to this section were received from DCIDA, PSU and SolarCity. In its comments, DCIDA references its previous comments under Section 75.13(a)(6) and states that the Commission has not responded to the IRRC's inquiry to justify the alleged costly burden to have systems over 500 kilowatts reviewed and approved for net metering by the Commission. DCIDA ANoFR Comments at 10. PSU avers that the added review time creates an undue burden and discourages the research, deployment and development of renewable energy systems. PSU ANoFR Comments at 17-18.

In its comments, SolarCity states that the proposed procedure for Commission approval for alternative energy systems with a nameplate capacity of 500kW or greater will further delay project development timelines. SolarCity notes that all customer-generators are required to size the alternative energy system to generate no

more than 200% of the customer-generator's annual electric consumption, regardless of nameplate capacity. SolarCity suggests that any inconsistency in the application of net metering rules or the application of an EDC's tariff should be dealt with by the respective EDC prior to granting approval to interconnect. SolarCity ANoFR Comments at 1.

4. Disposition

The Commission reviewed the comments submitted in reference to the proposed shortened review time for EDCs to submit an application with its recommendation to TUS. We agree that revising this section to 15 days instead of 20 days could jeopardize safety and reliability. As such, we increase the time EDCs have to submit an application with its recommendation to TUS from 15 days to 20 days, as previously proposed in the NoPR. We note, however, that these are calendar days and not business days. In response to IRRC's comments, we also note that the proposed regulation does not prohibit this review process from running concurrent with the interconnection timelines in subchapter (c), and we anticipate that they would. We also find that this timeline will not unreasonably delay the employment of an alternative energy system as the timeline is similar to the interconnection timelines and should run concurrently with those timelines. Furthermore, we note that we are not seeking anything in this process that the developer would not already be required to provide the EDC. The Commission finds that these timelines appropriately balance the rights of all interested parties while providing little or no delay in the development of new alternative energy systems. Accordingly, this subsection is adopted as found in Annex A.

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 as 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 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.

1. Comments

Comments supporting the changes proposed in the NoPR to the definition of electric nameplate capacity were received from PPL and SEF. PPL NoPR Comments at 23, PPL ANoFR Comments at 30, SEF NoPR Comments at 2.

Comments opposing the changes proposed in the NoPR to the definition of electric nameplate capacity were received from SRECTrade. SRECTrade urges the Commission to elaborate on this definition as to its applicability to the alternative energy credit certification under Section 75.63. As is, it is unclear whether the nameplate capacity as used in Section 75.63 is subject to the revised definition under Section 75.22, or if the nameplate capacity as used in Section 75.63 will continue to reference the facility's DC capacity. SRECTrade NoPR Comments at 5.

2. Disposition

As described above, electric nameplate capacity is based on 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. The Commission finds that the proposed changes to the definition of electric nameplate capacity in Section 75.22 does not conflict with the language relating to the alternative energy credit certification under Section 75.63. Nameplate capacity refers to the maximum watt output the system is capable of generating at any given time. Section 75.63 refers to the certification of alternative energy credits, which represents one megawatt-hour of generation from the alternative energy system or the actual generation output over time. Any reference to nameplate capacity found in Section 75.63 has the same meaning as that being established in Section 75.22. Consequently, the Commission adopts the proposed language to the definition of electric nameplate capacity 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 for customer-generators from 2 MW to 5 MW found in Act 35.

1. Comments

PPL provided comments supporting the changes proposed in the NoPR and ANoFR to these sections. PPL NoPR Comments at 23, PPL ANoFR Comments at 30. PECO notes that various requirements of the interconnection provisions have been revised to indicate that qualifying facilities may be equal to or less than five megawatts. PECO believes that this designation will lead to confusion over the allowable nameplate capacities for commercial customers. PECO fears that applicants may mistakenly believe it is acceptable to interconnect a system between three and five megawatts without having to comply with the requirements and specifications emphasized in this rulemaking for large customer-generators. To avoid such misunderstandings, PECO recommends that the Commission revise the proposed regulations to clarify that systems with nameplate capacities between three and five megawatts are only allowable if they comply with the requirements set forth in the definition of customer-generator. PECO ANoFR Comments at 10-11.

FirstEnergy states that it has very serious concerns about the proposed changes to the level of review process for generators with electric nameplate capacities between two and five megawatts. The existing regulations call for Level 3 review for any application over two megawatts, whereas under the current proposal, virtually all applications greater than ten kilowatts, with the exception of rotating equipment, would be eligible for a Level 2 review. Reducing the level of review for projects exceeding two megawatts implicates the safety and reliability of an EDC's system, and suggests that this revision be rejected. FirstEnergy ANoFR Comments at 6-8.

2. Disposition

The Commission agrees with FirstEnergy that changing the interconnection review procedures for Level 2 small generation facilities to five megawatts as proposed in NoPR negatively impacts the safety and reliability of the EDC's system. Therefore, as defined

in Section 75.34, the electric nameplate capacity rating for Level 2 interconnection review procedures will remain as two megawatts or less. As for applicability and interconnection review procedures for Level 3 and 4, as described in Sections 75.31, 75.39 and 75.40, the electric name plate capacity ratings that shall be used are five megawatts or less, as proposed.

H. Interconnection: § 75.51. Disputes

The current regulations at § 75.51(c) provide 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.

1. Comments

PPL provided comments supporting the proposed changes in the NoPR regarding the removal of the technical master. PPL NoPR Comments at 23, PPL ANoFR Comments at 30.

Comments opposing the proposed changes were received from PennFuture and DWEA/UW. PennFuture NoPR Comments at 10, DWEA/UW NoPR Comments at 9, and PennFuture Energy Center NoPR Comments at 2. DWEA/UW states that it

understands the Commission has not made use of its power to appoint a technical master, but nevertheless recommends that the Commission retain the provisions proposed for deletion. DWEA/UW is particularly concerned that residential customers and small businesses are already at a disadvantage when faced with disputes regarding the technical application of the regulations and, with increasing complexity, this is expected to continue. For this reason, DWEA/UW asserts that it is premature to delete the provisions. Furthermore, DWEA/UW states that even if the Commission does not make use of its power to designate a technical master, that ability, and the ability of an appointed master to determine costs for the review, serves as an incentive for the parties to make effective use of the existing alternative dispute resolution process. DWEA/UW NoPR Comments at 9.

In its comments, the IRRC notes that given the potential for more disputes arising as a result of the implementation of this rulemaking, the IRRC questions the reasonableness of this change at this time and asks the Commission to provide a fiscal analysis of the costs associated with the designation by the Commission of a technical master. IRRC NoPR Comments at 8.

Opposing comments to the ANoFR regarding the removal of the technical master were received from PA IPL, PennFuture and the Joint Commentators. PA IPL and PennFuture state that it is not supporting the proposed deletion in Section 75.51(c) of the Commission's ability to appoint a technical master to assist in the resolution of any disputes under the interconnection application/review process. PennFuture understands the Commission has not made use of its power to appoint a technical master, but nevertheless sees no reason to cancel this authority. PennFuture is particularly concerned that residential customers and small businesses are already at a disadvantage when faced with disputes regarding the technical application of the regulations and, with increasing complexity, this is expected to continue. For this reason, PennFuture asserts that it is

premature to delete the provisions. PA IPL ANoFR Comments at 3. PennFuture ANoFR Comments at 2.

The Joint Commentators state that although the technical master provision has not been used thus far, that is not a sufficient reason to remove the option altogether. The Joint Commentators assert that removing the technical master option hurts residential owners and small businesses who likely cannot afford to hire an attorney or a technical expert to represent them if there is ever a dispute over their generation amount, net metering, etc. The Joint Commentators state that considering the complexity that an additional percentage based cap and the virtual net metering physical aggregation requirement creates, generators are more likely to see an issue arise than under the old rule. The Joint Commentators assert that having a technical master serve as a mediator is a valuable option that needs to remain in the regulation. Joint Commentators ANoFR Comments at 12-13.

2. Disposition

After reviewing all comments, the Commission is not convinced that having the option to designate a technical master as a mediator is in fact necessary. 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. The assertions by PennFuture, Pa IPL and the Joint Commentators are misplaced for several reasons. Initially, it must be noted that the current regulation does not eliminate the costs borne by those seeking a review by a technical master as opposed to hiring their own experts. The current regulations simply require the Commission to approve the costs for the technical master to be borne by those customers who seek such a review.

Furthermore, the technical master would only review the actual physical interconnection of the generation system with the distribution system. The technical

master has no role in determining whether the generation owner qualifies for net metering as PennFuture and the Joint Commentators suggest. The current regulation specifically states that "[u]pon designation, the parties shall use the technical master to resolve disputes related to *interconnection*." 52 Pa. Code § 75.51 (relating to disputes) (emphasis added). The physical interconnection only gets more complicated as the size of the generator increases and applies to all generators, whether they qualify for net metering or not. Accordingly, the provisions of this rulemaking related to net metering have no bearing on the complexity or costs of the physical interconnection as PennFuture and the Joint Commentators imply.

Regarding IRRC's request that we provide a fiscal analysis of the costs associated with designating a technical master, we are unable to provide such data. As this provision has never been used, and the Commission has never reviewed or approved any costs for a technical master, the Commission has no information or experience to base such an analysis. Furthermore, we note that the costs are likely to vary depending on the experience level of the chosen technical master and the time, as well as any travel and lodging expenses, the technical master would devote to any individual dispute. In light of these variables and the lack of available relevant data, any fiscal analysis or projection the Commission would provide on this issue would be speculative at best. For these reasons, we adopt the deletion of 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).

Comments supporting the proposed changes in the NoPR regarding this section were received from FirstEnergy and PPL. FirstEnergy supports the changes, it, however,

feels that additional revisions are necessary to make the compliance process more accurate, administratively convenient and financially stable. FirstEnergy NoPR Comments at 8, PPL NoPR Comments at 23, PPL ANoFR Comments at 30.

No opposing comments were received to Section 75.61(b). IRRC's and other commentators' concerns regarding any impact on current owners of credits is addressed below under Section L. As such, we adopt the proposed language that the alternative energy portfolio requirements are subject to the quarterly adjustment provisions of Act 129 of 2008.

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.

Comments supporting the proposed changes in the NoPR regarding this section were received from FirstEnergy and PPL. FirstEnergy NoPR Comments at 8, PPL NoPR Comments at 23, PPL ANoFR Comments at 30.

No opposing comments were received to Section 75.62(g). As such, we adopt the proposed language that alternative energy system status may be suspended or revoked for violations of the provisions of this chapter.

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) provide 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 the applicant 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.

1. Comments to Section 75.63(g)

Comments supporting the changes proposed in the NoPR to Section 75.63(g) were received from PPL and FirstEnergy. PPL NoPR Comments at 24, FirstEnergy NoPR Comments at 9. PPL states in its comments that it generally supports this proposal. PPL, however, notes that with respect to using estimated data for small systems, there must be

a limit implemented as to what it means to have or not have the technology to capture this data. PPL also recommends including a provision that the cost for any additional metering requested by a customer-generator be the responsibility of the customer-generator. PPL NoPR Comments at 24, PPL ANoFR Comments at 31.

Comments opposing the changes to Section 75.63(g) were received from SEF and SRECTrade. SEF NoPR Comments at 2, SRECTrade NoPR Comments at 6-8. SRECTrade states that this section 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. SRECTrade suggests that the language should be modified to clarify that all facilities *greater than* 15 kW shall be verified using metered data, and that facilities 15 kW or less may be verified using either metered data or estimates. SRECTrade recognizes that the Commission intended to propose these revisions in an effort to require all new solar photovoltaic systems to have a revenue grade meter to measure system output, but SRECTrate asserts that this requirement is far more burdensome than the cost of a revenue grade meter alone. SRECTrade argues that while the cost of a revenue grade meter may have decreased in recent years, the burden of requiring small systems to report their generation in lieu of utilizing estimates has not changed. SRECTrade asserts that this requirement will have the impact of discouraging small systems from obtaining alternative energy credit certification or deterring existing facilities from expanding. SRECTrade NoPR Comments at 6-8.

2. Disposition to Section 75.63(g)

The Commission disagrees with SRECTrade that the requirement that all new alternative energy systems be metered, including small solar photovoltaic systems with a nameplate capacity of 15 kW or less, will unreasonably burden the development of such systems. We find that the metering is necessary to ensure that all systems are actually

producing generation and that the generation amount is accurately reported. The use of estimates provides an average output, at best, for these systems that may be higher or lower than the actual system output. We note that inverter readings for these small systems are acceptable meter data, as the inverters accurately measure the output, eliminating any cost concerns related to purchasing a revenue grade electric meter. While there may be some inconvenience imposed on system owners to read and report the meter readings, the Commission is not convinced that the inconvenience is unreasonable. We further note that owners of alternative energy systems are not required to participate in alternative energy credit (AEC) markets, and are free to pick and choose when to participate based on many reasons, including the effort involved in reporting system output and the price they get for the AECs they generate. Finally, we note that systems with a nameplate capacity of just over 15 kW have always been required to use metered data, and we find that the metering requirement is no more burdensome than that placed on these other small systems.

In conclusion, we find that the benefit of more accurate generation output readings results in more reliable and accurate AECs and outweighs the minimal cost and inconvenience this new requirement imposes. For these reasons, we adopt Section 75.63(g) as proposed.

3. Disposition to Sections 75.63(i), (j) and (k)

FirstEnergy provided comments supporting the changes proposed in the NoPR to Section 75.63(i). FirstEnergy NoPR Comments at 9. No other comments were received regarding changes to these subsections.

Accordingly, we adopt the proposed language to Section 75.63(i) clarifying 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. In addition, we adopt the proposed language to Sections 75.63(j) and (k).

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.

1. Comments to Section 75.64(b)

PPL provided comments supporting the changes proposed in the NoPR to Section 75.64(b). PPL NoPR Comments at 24, PPL ANoFR Comments at 31.

PECO and FirstEnergy provided comments opposing the changes proposed in the NoPR to Section 75.64(b). PECO states that it appreciates the Commission's desire to clarify the authority of the program administrator with respect to non-compliant alternative energy systems. PECO, however, has 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. 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. PECO asserts that 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. PECO NoPR Comments at 11-12, PECO ANoFR Comments at 11-12.

FirstEnergy agrees with the Commission's proactive approach to addressing fraudulent AEC supplier practices; it, however, contends that the prescribed punishment must be careful not to impact innocent market participants. For instance, FirstEnergy notes that where AECs have been purchased and used, or are going to be used for compliance, having the AECs invalidated could place a huge financial and regulatory burden on market participants who have transacted for properly certified AECs for use at the time of purchase. FirstEnergy suggests that, in order to avoid potential undue harm to innocent parties, AECs from a facility that has been deemed non-compliant but which have already been sold and transferred from the seller's account to the purchaser remain valid for compliance use by the purchaser. FirstEnergy goes on to state that current AECs that have not been sold and transferred, as well as future AECs, would be addressed as defined within the rulemaking. FirstEnergy also suggests that the Commission consider a

financial penalty, including the disgorgement of profits from the fraudulent seller, for AECs that have already been sold and transferred in order to create a disincentive for such action without impacting innocent market participants. FirstEnergy NoPR Comments at 9-10.

IRRC states that commentators have expressed concern with how alternative energy credits which are deemed to have been generated from non-complaint alternative energy systems will be treated. The concern is that current owners of the credits could be unfairly penalized for the non-compliance by an alternative energy system. This would have a negative impact on the current owner of the credit. To provide regulatory stability, the IRRC recommends that the Commission clarify how these credits will be treated. IRRC NoPR Comments at 8.

2. Disposition to Section 75.64(b)

Regarding concerns raised by IRRC, PECO and FirstEnergy, we initially note that that this provision simply identifies, for all interested parties, the possible actions the program administrator has authority to take regarding AECs. It does not dictate what action is to be taken in all fact patterns. The specific action the program administrator takes will be determined on a case-by-case basis dependent on the facts in each case, including whether the credits have been transferred to a third-party. We further note that any decision of the program administrator may be appealed to the Commission consistent with Section 5.44 (relating to petitions for appeal from actions of staff) of our Regulations. *See* 52 Pa. Code § 75.64(e). This subsection gives all interested parties notice to include provisions in contracts to account for these possible outcomes. Furthermore, we note that instances when such action can be taken by the program administrator involve situations where the validity of the credits produced or being produced is in question. In short, these provisions are being put in place to put all parties on notice that the Commission will not tolerate inappropriate manipulation of the AEC

market. We find that this provision will provide greater confidence to purchasers of AECs that the credits they purchase are valid.

Regarding FirstEnergy's suggestion that the Commission include a provision for penalties or the disgorgement of profits for system owners or aggregators that acted fraudulently, we find no provision, and FirstEnergy has not identified any provision, in the AEPS Act or the Public Utility Code giving the Commission such authority. We find that the remedies FirstEnergy seeks are best left to the contracting parties to account for and for the courts to determine. Accordingly, we adopt the changes to Section 75.64(b) as proposed.

3. Comments to Section 75.64(c)

PECO provided comments opposing the changes proposed for Section 75.64(c). PECO states that under this proposed section, 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. PECO asserts that 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. PECO NoPR Comments at 12-13, PECO ANoFR Comments at 12.

Comments submitted to the ANoFR, opposing the changes proposed to Section 75.64(c) were received from Duquesne and PECO. Duquesne ANoFR Comments at 4. PECO ANoFR Comments at 12. Duquesne recommends that the program administrator provide the EDCs and EGSs with an initial assessment of their compliance status prior to the program administrator's determination of compliance at the end of the true-up period.

Duquesne asserts that such an initial assessment would provide the EDCs and EGSs with notice of potential issues and give them an opportunity to cure and adjust their alternative energy credits that may be used for compliance to reduce the risk of having to make alternative compliance payments. Duquesne ANoFR Comments at 4.

4. Disposition to Section 75.64(c)

We reviewed all NoPR and ANoFR comments in reference to the proposed changes and are not persuaded that an initial assessment of the EDC and EGS compliance status prior to the program administrator's determination of compliance at the end of the true-up period is necessary. The Commission is merely clarifying timing and processes to determine and verify compliance with the AEPS Act obligations that are currently in use. We also note that based on past experience, the vast majority of EGSs have not retired credits to their Pennsylvania account until near the end of the 90 day true-up period, making any assessment 46 to 75 days into the true-up period pointless.

Furthermore, we note that the program administrator[14] is to be available to respond to questions and inquiries from all interested stakeholders, including EGSs and EDCs. As such, EGSs and EDCs are free to contact the program administrator any time before, during and after the true-up period the get the confirmation PECO and FirstEnergy seek. We find that EGSs and EDCs are run by sophisticated individuals who have the knowledge, information and experience to determine how and when to purchase and retire the appropriate amount of credits and confirm their compliance with the AEPS Act requirements. Accordingly, the language in Section 75.64(c) is hereby adopted as proposed.

[14] The Commission has the statutory authority under the AEPS Act to approve the independent entity that serves as the program administrator. 73 P.S. § 1648.3(e)(1).

5. Disposition to Section 75.64(d)

No comments opposing or supporting the changes proposed in the NoPR to Section 75.64(d) were received. As such, we adopt the proposed language to Sections 75.64(d) 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).

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.

PPL provided comments supporting the changes proposed for Section 75.65. PPL NoPR Comments at 24, PPL ANoFR Comments at 31. No other comments regarding this were received. Accordingly, we adopt the proposed language 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 NonSolar Tier I Obligation

In 2008, the General Assembly again amended the AEPS Act[15] 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-

[15] *See* P.L. 1592, No. 129 of 2008.

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.

1. Disposition of Section 75.71

PPL submitted comments supporting the language proposed in the NoPR to Section 75.71. PPL NoPR Comments at 24-25. No other comments were received regarding Section 75.71. Accordingly, we adopt Section 75.71 as proposed.

2. Comments to Section 75.72

PPL submitted comments supporting the proposed Section 75.72 with suggestions. PPL submits that there has been an ongoing issue with the annual alternative energy reporting requirements set forth in the existing regulations and reiterated in the NoPR. Specifically, PPL notes that the final end of year load numbers for EDCs and EGSs are due by June 30, one month after the end of the June-May period with no additional data being accepted after this date. PPL, however, notes that at this time final settlement data for the April and May periods are not available. PPL asserts that this data has a direct impact on the number of alternative energy credits required to obtain compliance for that year. PPL states that in some instances this leaves EDCs and EGSs with a shortfall based upon how bundled contracts are written. PPL recommends that the alternative energy credit reporting deadline be extended to 70 days after the year end to allow for final settlement values to be submitted, and that the compliance deadline be extended from August 30 to September 30 to accommodate the extended alternative energy credit reporting deadline. PPL NoPR Comments at 31-32.

FirstEnergy submitted comments opposing the proposed Section 75.72 with suggestion. Specifically, with respect to the reporting requirements for the quarterly adjustment of nonsolar Tier I obligations under subsections (a) and (b), FirstEnergy notes that the proposed practices in some cases impose a more strict time constraint than what

exists today. FirstEnergy asserts that such a narrowing of deadlines will create a greater burden on EDCs and EGSs to comply. In subsection (a)(1)-(4), FirstEnergy suggests that the reporting dates be extended by five calendar days beyond the proposed due dates to November 5, February 5, May 5 and July 5. This extension, FirstEnergy asserts, would address the reporting time constraints associated with the PJM 60-day reconciliation process. For subsection (a)(4) FirstEnergy notes that the 4th quarter data (March, April, May) due 30 days following the end of the quarter means that the May data must always be estimated. FirstEnergy suggests that if the Commission were to move the compliance period to a deadline of September 30 or October 5, EDCs could provide reconciled data for the entire compliance year. Finally, in subsections (b)(1)-(4) FirstEnergy suggests a modification of the sales data verification process to a least five business days in order to continue their current practices and ensure that sales data is properly validated and accurately reported. FirstEnergy NoPR Comments at 10-12.

PPL and EAP submitted comments opposing Section 75.72. PPL ANoFR Comments at 32, EAP ANoFR Comments at 5-6. PPL disagrees with the reporting requirement proposed in Section 75.72, mandating EDCs to report EDC and EGS load data. PPL states that EGSs provide retail competitive electric generation supply to end-use shopping customers. PPL asserts that the Commission's proposal to require EDCs to report EGS load data is extremely burdensome, time consuming, and ultimately shifts the EGSs' burden to report *their* customers' load and usage. PPL recommends that the Commission amend this provision to mandate that each load serving entity (LSE) be obligated to provide their own monthly load values. PPL suggest that the Commission may contact the EDC for support in instances only where an EGS does not provide their values in time or in instances where the Commonwealth believes the EGS reported value may be incorrect. PPL also believes the quarterly reporting periods should be changed to 65 days after the conclusion of the quarterly period. This additional time, PPL asserts, will allow all LSEs to report verified Settlement B values for all four quarterly periods.

PPL also recommends that the LSE transfer date of AECs to the State Account be moved from August 30 to September 30 if the Commonwealth believes it needs additional time to review credit transfers. PPL ANoFR Comments at 32.

EAP asserts that EDCs typically only report exceptions, not all monthly retail sales for each EGS, on a quarterly basis. EAP states that to do so for all sales would become administratively burdensome, particularly in those EDCs service territories where dozens or more EGSs are licensed to provide supply. EAP states that the onus for this report should fall on the individual EGS. If the Commission were to keep this suggested reporting requirement as proposed, EAP suggests that EDCs would need an additional five calendar days to accommodate the PJM reconciliation process. Similarly, EAP suggests that the Commission's recommendation for EGS verification of monthly sales data also be adjusted. EAP notes that the current practice the review is afforded five business days. EAP suggests codifying the informal practice of five business days in order to continue current procedures and ensure that the sales data is properly validated. EAP ANoFR Comments at 5-6.

3. Disposition for Section 75.72

After reviewing all NoPR and ANoFR comments received in regards to the reporting requirements for quarterly adjustment of nonsolar Tier I obligations, the Commission agrees that extending the reporting time by five days beyond the proposed dates is reasonable. Therefore, the following time frames are hereby adopted: First quarter (June, July and August) due by November 4, second quarter (September, October and November) due by February 4, third quarter (December, January and February) due by May 5.

Regarding suggestions that the Commission extend the fourth quarter and the compliance deadline date from August 30 to September 30, we decline to do so due to

administrative burdens related to the statutory deadline. The AEPS Act sets the true-up period as the end of the compliance year, May 31, until September 1. *See* 73 P.S. § 1648.2 (definition of true-up period). This true-up period is to provide EDCs and EGSs "the ability to obtain the required number of alternative energy credits or to make up any shortfall of the alternative energy credits they may be required to obtain to comply with [the AEPS Act]." 73 P.S. § 1648.3(e)(5). Extending the fourth quarter reporting period would extend the date when the program administrator could provide the final AEC requirements for each EDC and EGS, giving even less time for EDCs and EGSs to acquire and reserve the appropriate number of credits during the true-up period. Extending the deadline for final compliance determination to September 30 would not provide any benefit as the EGSs or EDCs would have no opportunity to true-up their accounts. For these reasons, we decline to adopt this suggestion.

Regarding the concerns raised by PPL and EAP about reporting EGS load data, we note that it is the EDC that has this meter data and reports it to PJM for settlement. The Commission is not asking for any other data. Also, we note that, to date, all other EDCs have been able to provide this data in a timely manner. In fact, PPL has also provided this data at times, when asked, as it suggested, to verify EGS data. We also find it significant that this data has been requested of and provided by EDCs since 2009, giving PPL more than five years to devise a process to provide the data. Finally, we note that the sooner the program administrator obtains data regarding all load, the sooner the quarterly adjustments can be computed and the sooner the EDCs and EGSs can be informed of their nonsolar Tier I requirements. Accordingly, we find that this requirement does not impose an undue burden on the EDCs.

CONCLUSION

Accordingly, under 66 Pa.C.S. §§ 501, 1501, 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),1648.3(e)(2); the Commonwealth Documents Law, 45 P.S. §§ 1201 *et seq.*, and the regulations promulgated hereunder at 1 Pa. Code §§ 7.1, 7.2, and 7.5, the Commission adopts the 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:

1. That the regulations at 52 Pa. Code Chapter 75 are amended as set forth in Annex A.

2. That the Secretary shall submit this order and Annex A to the Office of Attorney General for approval as to legality.

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

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

7. That these regulations shall become effective upon publication in the *Pennsylvania Bulletin.*

8. That 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 Alyson Zerbe, Regulatory Coordinator, Law Bureau, 717-772-4597.

BY THE COMMISSION

Rosemary Chiavetta
Secretary

(SEAL)

ORDER ADOPTED: February 11, 2016

ORDER ENTERED: February 11, 2016

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 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~~ DISTRIBUTION SYSTEM have DR and CRITICAL INFRASTRUCTURE load IN SUCH A COMBINATION SO AS TO GIVE THE EDC ~~have~~ the ability to SAFELY AND intentionally disconnect THAT SECTION OF THE DISTRIBUTION SYSTEM from THE REST OF THE DISTRIBUTION SYSTEM and operate IT AS AN ISLAND DURING EMERGENCY SITUATIONS~~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% OF A CUSTOMER-GENERATOR'S ANNUAL ELECTRIC CONSUMPTION OR SATISFIES THE CONDITIONS UNDER §75.13 (A)(3)(IV) (RELATING TO GENERAL PROVISIONS) SHALL BE EXEMPT FROM THE DEFINITION OF A UTILITY IN THIS CHAPTER. THIS TERM EXCLUDES BUILDING OR FACILITY OWNERS OR OPERATORS THAT MANAGE THE INTERNAL DISTRIBUTION SYSTEM SERVING SUCH BUILDING OR FACILITY AND THAT SUPPLY ELECTRIC POWER AND OTHER RELATED POWER SERVICES TO OCCUPANTS OF THE BUILDING OR FACILITY.**

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% 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 MONTHS PRIOR TO SUBMISSION OF THE CUSTOMER-GENERATOR'S INTERCONNECTION REQUEST.

(II) FOR NEW SERVICE LOCATION ACCOUNTS, 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.

(III) THE 200% 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 DOES NOT APPLY TO ALTERNATIVE ENERGY SYSTEMS WHEN THE DEPARTMENT PROVIDES CONFIRMATION TO THE COMMISSION THAT A CUSTOMER-GENERATOR'S ALTERNATIVE ENERGY SYSTEM COMPLIES WITH THE DEPARTMENT'S PENNSYLVANIA CHESAPEAKE WATERSHED IMPLEMENTATION PLAN IN COMPLIANCE WITH SECTION 303 OF THE FEDERAL CLEAN WATER ACT AT 33 USC § 1313 (RELATING TO WATER QUALITY STANDARDS AND IMPLEMENTATION PLANS) OR IS AN ELEMENT OF A FARM'S APPROVED NUTRIENT MANAGEMENT PLAN IN COMPLIANCE WITH THE NUTRIENT MANAGEMENT ACT AT 3 PA. C.S. §§ 501, *ET SEQ.* (RELATING TO NUTRIENT MANAGEMENT AND ODOR MANAGEMENT).

(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~~.~~, EXCEPT WHEN

~~(6) The~~THE alternative energy system ~~must have~~HAS a nameplate capacity 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 **KILOWATT-HOUR** 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 **KILOWATT-HOUR** 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 KILOWATT-HOUR RATE credit shall be applied monthly AGAINST KILOWATT-HOUR DISTRIBUTION USAGE. 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 KILOWATT-HOUR distribution usage in subsequent billing periods until the end of the year when all remaining unused KILOWATT-HOUR 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~~SERVICE LOCATIONS to be aggregated must be EDC SERVICE LOCATION ACCOUNTS**

HELD BY THE SAME INDIVIDUAL OR LEGAL ENTITY receiving RETAIL electric ~~generation~~ service FROM THE SAME EDC 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.

* * * * *

§ 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 **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 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 **AN EDCS** submission **RECOMMENDING APPROVAL. IF DISAPPROVED, THE BUREAU OF TECHNICAL UTILITY SERVICES WILL**~~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 BUREAU OF TECHNICAL UTILITY SERVICES WILL APPROVE OR DISAPPROVE THE 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)~~**(G)** 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** **2** 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** **2** 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.

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(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.

* * * * *

§ 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~~**NOVEMBER 4**.

(2) Second quarter (September, October and November) due by ~~January 30~~**FEBRUARY 4**.

(3) Third quarter (December, January and February) due by ~~April 30~~**MAY 5**.

(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~~**NOVEMBER 4**.

(2) Second quarter (September, October and November) due by the second business day after ~~January 30~~**FEBRUARY 4**.

(3) Third quarter (December, January and February) due by the second business day after ~~April 30~~**MAY 5**.

(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).

PENNSYLVANIA PUBLIC UTILITY COMMISSION
Harrisburg, Pennsylvania 17105-3265

Implementation of the Alternative Energy Portfolio Standards Act of 2004

Public Meeting held February 11, 2016
2404361-LAW
Docket No. L-2014-2404361

STATEMENT OF CHAIRMAN GLADYS M. BROWN

Before the Commission for consideration and disposition is the Final Rulemaking Order proposing amendments to our regulations at 52 Pa. C.S. §§ 75.1-75.70, which implement the net metering, interconnection, and compliance provisions of the Alternative Energy Portfolio Standards Act (AEPS Act), 73 P.S. § 1648.1, *et seq.*

With one notable exception, I support the proposed amendments to our regulations and believe that they succeed in implementing the changes to the AEPS Act made by Act 35 of 2007, explaining changes generated by Act 129 of 2008, and, generally clarifying compliance obligations.

However, I am unable to support the proposed amendment of Section 75.13(3) of the regulations that would require an alternative energy system to be sized to generate no more than 200% of the customer generator's annual electric consumption at the interconnection meter and all qualifying virtual meter aggregation locations. The rationale for imposing the 200% limit is noble in that it recognizes that any above market payments made to customer generators are paid for by the rest of the rate paying class of customers. Because, one of the basic tenets of public utility regulation, per 66 Pa. C.S. § 1301, is to set rates that are "just and reasonable," any rational regulator would be tempted to limit a customer generator from being paid retail rates for energy produced by a system that was purposefully oversized. But, setting such a limit ignores the very specific size limitation provided in the AEPS Act.

The 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, except for customers whose systems are above three megawatts and up to **five megawatts** who make their systems available to operate in parallel with the electric utility during grid emergencies as defined by the regional transmission organization ..." 73 P.S. § 1648.2 (emphasis added). Because the AEPS Act very precisely provides that customer generators may size up to 50kw for residential systems and up to 3 or 5 MW for non-residential systems, this Commission commits legal error by imposing a different size limitation in our regulations.[1] The

[1] An agency has no power to "tailor" legislation to bureaucratic policy goals by rewriting unambiguous statutory terms. Agencies exercise discretion only in the interstices created by statutory silence or ambiguity; they must always "'give effect to the unambiguously expressed intent of Congress.'" It is hard to imagine a statutory term less ambiguous than the precise numerical thresholds at which the Act requires PSD and Title V permitting. When EPA

statutory requirement that utility rates be just and reasonable does not authorize the Commission to ignore or alter other statutory directives. *Popowsky v. Pa. PUC*, 910 A.2d 38, 53 (Pa. 2006).

Because of this error, I am unable to fully support the staff recommendation and will dissent, in part.

February 11, 2016
Date

Gladys M. Brown, Chairman

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replaced those numbers with others of its own choosing, it went well beyond the "bounds of its statutory authority." *Utility Air Regulatory Group v. EPA*, 573 U.S. ___, ___, 134 S. Ct. 2427, 2445, 189 L. Ed. 2d 372, 392 (2014) (citations omitted).

PENNSYLVANIA PUBLIC UTILITY COMMISSION
HARRISBURG, PENNSYLVANIA 17105

Implementation of the Alternative Energy Portfolio Standards Act of 2004.	**Public Meeting: February 11, 2016** **2404361-LAW** **Docket L-2014-2404361**

STATEMENT OF VICE CHAIRMAN ANDREW G. PLACE

Before the Commission is the Final Rulemaking Order (Rulemaking) amending Chapter 75, the Alternative Energy Portfolio Standards and which focuses, in part, on Net Metering. At the outset, I must congratulate our staff on the thorough analysis of the competing issues contained within this rulemaking.

I agree foremost with the concept annunciated in the Rulemaking that the Alternative Energy Portfolio Standards Act (AEPS Act) and Act 129 must be read together. I agree with the Rulemaking's effort to assure that the retail value the "customer generator" receives pursuant to the net metering requirements of the AEPS Act is also "the least cost to the customers over time" as is required by Act 129. 66 Pa.C.S. §2807 (e) (3.4). However, it is axiomatic that the Commission, as a creature of the legislature, has only those powers conferred upon it by statute. *See Feingold v. Bell*, 477 Pa. 1, 383 A. 2d 791 (1977). Therefore I must oppose the Rulemaking because I believe that it goes beyond the Commission's authority.

I believe that the public, including "customer generators" and retail customers, would be better served if the Commission were to focus on reevaluating "retail value" rather than adding further constraints to those already contained in the statutory definition of customer generators. Currently our regulations provide that the "price to compare" is the "retail value" and I believe that the Commission could facilitate the development of alternative energy and ensure the purchase of the alternative energy at "least cost" to the customer by redefining "retail value" by regulation. See generally, 52 Pa. Code §75.13 (c) and (d).

Many of the benefits of net metered distributed generation can be valued through measurable elements and include reductions of the socialized costs of energy and capacity market prices; avoided distribution and transmission investments and line losses; and future ancillary benefits associated with advancements in smart inverters. Further, these benefits include the environmental compliance costs embedded in the price for capacity and energy. On the other side of the ledger, as net metering market penetration expands, there may be a need to account for incremental costs related to high density deployment of net metered facilities on the distribution grid. Lastly, "retail value" may be dynamic

over time as these costs and benefits are altered by changes in energy demand across the energy landscape.

In summary, I firmly believe that consumers are best served by getting the "retail value" price right, rather than by seeking to impose net metering capacity restrictions which are not in the Act. Sufficient market signals exist to achieve both the goal of supporting the deployment of alternative generation as well as the obligation to do so at a cost that matches the consumer benefits of retail distributed generation. This approach is both regulatorily efficient as well as cost effective.

DATE: February 11, 2016

Andrew G. Place
Vice Chairman

PENNSYLVANIA PUBLIC UTILITY COMMISSION
HARRISBURG, PENNSYLVANIA 17120

Implementation of the Alternative Energy Portfolio Standards Act of 2004	**Public Meeting: February 11, 2016** **2404361-LAW** **Docket No. L-2014-2404361**

STATEMENT OF
COMMISSIONER ROBERT F. POWELSON

Before the Commission today for disposition is the Final Rulemaking Order (Order) updating several of the Commission's Regulations implementing the Alternative Energy Portfolio Standards Act of 2004 (AEPS Act). While the Order disposes of several issues pertaining to the AEPS Act, the provisions updating our regulations on net metering have been particularly contentious.

I firmly believe that all of the new regulations contained in the Order being voted on today are much-needed consumer protections, particularly the 200% limitation on systems that are eligible for net metering and the clarification of the definition of virtual meter aggregation. These regulations are narrowly tailored to balance the Commonwealth's policy of promoting the development of renewable generation sources with the Commission's mandate of maintaining affordable and reliable electricity service for consumers. Further, I do not believe that these regulations impose any unreasonable burdens on the responsible development of renewable generation sources.

It is worth noting the lengthy input process the Commission has undertaken while considering these proposed reforms. On February 20, 2014, the Commission first asked for comment on proposed regulations. Due to intense interest in this matter, the Commission extended the initial comment period to ensure that all interested stakeholders had an opportunity to be heard. After carefully reviewing all of the comments submitted in response to our proposed regulations, the Commission made further changes to our proposed rules and solicited yet another round of comments to ensure that every stakeholder's voice was adequately heard. An almost unprecedented number of stakeholders from diverse industries provided input to the Commission and every single comment was carefully considered. As a result of that input, I believe that the regulations set forth in the Order appropriately balance the interests of all stakeholders, including those of the agricultural community.

It is important to note that the reforms contained in the new regulations are not occurring in a vacuum – similar discussions are occurring nationwide as the need to revisit net metering is being, and has been, recognized in other states, such as Nevada and Arizona. As is outlined in the Order, these new regulations are less restrictive that those found in many other jurisdictions. Just as in those other jurisdictions, the Commission could not stand by and ignore issues created by the absence of firm rules governing net metering.

Lastly, I want to recognize our legal and technical staff for their work in crafting today's Order. The Order is balanced, clear and well written, which was no easy task considering the numerous competing comments and staff is to be commended.

Robert F. Powelson

ROBERT F. POWELSON
COMMISSIONER

Date: February 11, 2016

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March 22, 2016

GLADYS M. BROWN
CHAIRMAN

The Honorable John F. Mizner, Chairman
Independent Regulatory Review Commission
14th Floor, Harristown II
333 Market Street
Harrisburg, PA 17101

Re: L-2014-2404361/57-304
Final Rulemaking Re Implementation of the
Alternative Energy Portfolio Standards Act of 2004
52 Pa. Code, Chapter 75

Dear Chairman Mizner:

Enclosed please find one (1) copy of the regulatory documents concerning the above-captioned rulemaking. Under Section 745.5(a) of the Regulatory Review Act, the Act of June 30, 1989 (P.L. 73, No. 19) (71 P.S. §§745.1-745.15) the Commission, on June 23, 2014, submitted a copy of the Notice of Proposed Rulemaking to the Senate Committee on Consumer Protection and Professional Licensure, the House Consumer Affairs Committee and the Independent Regulatory Review Commission (IRRC). This notice was published at 44 *Pa.B.* 4179 on July 5, 2014. The Commission also provided the Committees and IRRC with copies of all comments received in compliance with Section 745.5(b.1).

In preparing this final form rulemaking, the Commission has considered all comments received from the Committees, IRRC and the public.

Sincerely,

Gladys M. Brown
Chairman

Enclosures
pc: The Honorable Robert M. Tomlinson
The Honorable Lisa Boscola
The Honorable Robert Godshall
The Honorable Peter J. Daley, II
June Perry, Legislative Affairs Director
Bohdan Pankiw, Chief Counsel
Kriss Brown, Assistant Counsel
Alyson Zerbe, Regulatory Coordinator

TRANSMITTAL SHEET FOR REGULATIONS SUBJECT
TO THE REGULATORY REVIEW ACT

ID Number: L-2014-2404361/57-304

Subject: Final Rulemaking Re Implementation of the Alternative Energy Portfolio Standards Act of 2004
52 Pa. Code Chapter 75

Pennsylvania Public Utility Commission

TYPE OF REGULATION

_____ Proposed Regulation

_____ Final Regulation with Notice of Proposed Rulemaking Omitted.

__X__ Final Regulation

_____ 120-day Emergency Certification of the Attorney General

_____ 120-day Emergency Certification of the Governor

FILING OF REPORT

Date	Signature	Designation
3/22/16	[signature]	HOUSE COMMITTEE (Godshall)
		Consumer Affairs
3/22/16	[signature]	SENATE COMMITTEE (Tomlinson)
		Consumer Protection and Professional Licensure
3/22/16	K Cooper	Independent Regulatory Review Commission
		Attorney General
		Legislative Reference Bureau