RULES AND REGULATIONS

Title 12—COMMERCE, TRADE AND LOCAL GOVERNMENT

DEPARTMENT OF COMMUNITY AND ECONOMIC DEVELOPMENT

[12 PA. CODE CH. 145]

Corrective Amendment to 12 Pa. Code §§ 145.3 and 145.31

The Department of Community and Economic Development has discovered discrepancies between the agency text of 12 Pa. Code §§ 145.3 and 145.31 (relating to scope; and requirement of certification) as deposited with the Legislative Reference Bureau and the official text as published at 46 Pa.B. 6976, 6984, 6985 (November 5, 2016). The dates in 12 Pa. Code §§ 145.3 and 145.31(c) were incorrect.

Therefore, under 45 Pa.C.S. § 901: the Department has deposited with the Legislative Reference Bureau a corrective amendment to 12 Pa. Code §§ 145.3 and 145.31. The corrective amendment to 12 Pa. Code §§ 145.3 and 145.31 is effective as of November 6, 2017, the effective date of adoption of the final-form rulemaking amending these sections.

The correct versions of 12 Pa. Code §§ 145.3 and 145.31 appear in Annex A.

(*Editor's Note*: See 46 Pa.B. 7269 (November 19, 2016) for a document correcting the preamble of the final-form rulemaking published at 46 Pa.B. 6976.)

Annex A

TITLE 12. COMMERCE, TRADE AND LOCAL GOVERNMENT

PART V. COMMUNITY AFFAIRS AND DEVELOPMENT

Subpart C. COMMUNITY DEVELOPMENT AND HOUSING

CHAPTER 145. INDUSTRIAL HOUSING AND COMPONENTS

GENERAL PROVISIONS

§ 145.3. Scope.

Except to the extent otherwise stated in the act and the provisions of this chapter and in other applicable laws of the Commonwealth which are not inconsistent with or superseded by the act and this chapter, this chapter governs the design, manufacture, storage, transportation and installation of industrialized housing, buildings, and housing or building components which are sold, leased or installed, or are intended for sale, lease or installation, for use on a site in this Commonwealth. Industrialized buildings manufactured before November 6, 2017, may continue to be utilized in this Commonwealth subject to approval of the local code official.

SCOPE

§ 145.31. Requirement of certification.

(a) No person may sell, lease or install for use on a site in this Commonwealth industrialized housing, buildings, or housing or building components unless the industrialized housing, building, or housing or building component is certified and bears insignia of certification issued by the Department. The insignia of certification issued by the Department shall be attached to the industrialized housing, building, or housing or building component under this chapter, and they shall be subject to subsequent removal in accordance with this chapter.

(b) Industrialized housing, buildings, and housing or building components of the manufacturer which have never been occupied and which serve for model or demonstration purposes for the manufacturer do not have to bear insignia of certification under this chapter until the time that the industrialized housing, building, or housing or building components are first offered for sale or lease.

(c) This chapter does not apply to industrialized buildings or building components produced before November 6, 2017.

[Pa.B. Doc. No. 16-1984. Filed for public inspection November 18, 2016, 9:00 a.m.]

DEPARTMENT OF COMMUNITY AND ECONOMIC DEVELOPMENT

[12 PA. CODE CH. 145]

Industrial Housing and Components; Correction

Errors occurred in the preamble of the final-form rulemaking published at 46 Pa.B. 6976 (November 5, 2016) regarding references to the dates in §§ 145.3 and 145.31(c) (relating to scope; and requirement of certification). The affected portions of the preamble are corrected as follows. The remainder of the preamble to the final-form rulemaking is accurate as published.

(*Editor's Note*: See 46 Pa.B. 7269 (November 19, 2016) for corrective amendments to §§ 145.3 and 145.31.)

DENNIS M. DAVIN,
Secretary

Comments to Proposed and Draft Final-Form Rulemakings

This final-form rulemaking complies with the amendments to section 4(j) of the act (35 P.S. § 1651.4(j)) as amended by Act 8 mandating that the Department promulgate regulations to administer a certification program to oversee the production, installation and inspection of industrialized buildings, as opposed to industrialized housing. Thus, this regulation cannot comply with section 4(d) of the act, as section 4(d) of the act deals only with industrialized housing, not industrialized buildings. As previously stated, §§ 145.3 and 145.31 have been revised to make clear that these sections apply to industrialized housing, buildings, or housing or building components produced after November 6, 2017.

Analysis

Section 145.31 is amended to include industrialized buildings and building components in the requirements of certification and to eliminate unnecessary regulation. In the draft final-form rulemaking, this section was revised to provide that Chapter 145 would apply to industrialized housing, buildings, or housing or building components produced after the effective date of the final-form rulemaking. The section was then revised in this final-form rulemaking from the draft final-form rulemaking per the MBI's request by providing that Chapter 145 does not apply to industrialized housing, buildings, or housing or building components produced before November 6, 2017.

Tolling Letter Analysis

On August 30, 2016, at the suggestion of IRRC, the Department tolled the review period for this final-form rulemaking and resubmitted the regulations to IRRC, the House Commerce Committee and the Senate Community, Economic and Recreational Development Committee with the following changes:

• Section 145.3 was revised to clarify that the effective date of this final-form rulemaking is 1 year from publication in the *Pennsylvania Bulletin* and industrialized buildings manufactured before the effective date of this final-form rulemaking may continue to be utilized in this Commonwealth subject to approval of the local code official. The clarification was accomplished by:

o Adding a sentence to state that industrialized buildings manufactured before the effective date of this final-form rulemaking may continue to be utilized in the Commonwealth subject to approval of the local code official.

• Section 145.31(c) was revised to clarify that the effective date of this final-form rulemaking is 1 year from publication in the *Pennsylvania Bulletin* and Chapter 145 does not apply to industrialized buildings or building components produced before the effective date of this final-form rulemaking. The clarification was accomplished by adding subsection (c).

[Pa.B. Doc. No. 16-1985. Filed for public inspection November 18, 2016, 9:00 a.m.]

Title 22—EDUCATION

STATE BOARD OF PRIVATE LICENSED SCHOOLS

[22 PA. CODE CH. 73]

Fees

The State Board of Private Licensed Schools (Board), under the authority in the Private Licensed Schools Act (act) (24 P.S. §§ 6501—6518), amends § 73.151 (relating to fees) to read as set forth in Annex A.

Description and Need for Amendments

The amendments to § 73.151(a) prescribe amended fees for biennial licensure or registration of all schools and licensure of admissions representatives. The amendments to § 73.151(b) increase the user fees for other services provided by the Board. The Board's fees are fixed by § 73.151. Section 10 of the act (24 P.S. § 6510) authorizes the Board to increase its fees by regulation if the Board's revenues from fees, fines and civil penalties are not sufficient to meet Board expenditures over a 2-year period.

The Board recently reviewed its fees and determined that its existing fee structure was inadequate to meet revenue needs. The Board estimated that its expenditures for the biennial period covering Fiscal Years 2014-2015 and 2015-2016 would be $1,955,300. In contrast, the estimated revenues under the existing fee structure were anticipated to be $1,066,708. The projected shortfall of $888,592 was covered by the surplus in the Board's revolving account, which is currently $1,246,770, leaving a very minimal surplus to cover operating costs after July 1, 2016.

The fees in § 73.151 should raise sufficient revenue to offset the Board's projected expenditures for approximately 5 years.

The Board last increased its fees at 32 Pa.B. 1844 (April 13, 2002). At that time, the Board projected that the fees would cover 10 years of operating expenses. The 2002 fee structure sustained the Board's operation longer than anticipated.

The current staffing level will need to be maintained for the foreseeable future. While there has not been a change to the actual number of staff supporting the work of the Board since 2002, one position dedicated to specialized associate degrees was covered by general funds until 2010 because the work is governed by regulations promulgated by the State Board of Education. That position was transferred to the Board account in 2010 because the work services the private licensed school community. This change adds a financial burden on the Board's funds.

Revenue has been reduced in recent years as changes in Federal regulations and economic conditions have resulted in a significant reduction in the number of licensed schools from 325 in 2002 to 270 today. While revenue is reduced in accordance with the number of schools renewing licenses, staffing needs are not directly tied to the number of schools because most services need to be provided regardless of the number of licensed schools.

Most of the Board's revenue is generated by renewal fees. After 1 year of operation, biennial renewal fees are on an assessed graduated scale based upon gross tuition revenue. Additional revenue is generated by other service fees.

The following calculations include a cap of $35,000 that was accepted by the Board in May 2015 and used in these calculations. The original material did not clarify that this cap was in place. The largest schools are currently capped at $4,400 and this increase in the cap to $35,000 will ensure that the largest schools carry more of the burden of funding the Board's operation.

To accommodate the need for additional revenue the Board is raising its fees. The following table shows former fees and the amended fees:

	Board Activity	*Former Fee*	*Amended Fee*
1.	Initial School License	$1,500	$7,500
2.	Initial School License for Schools Presenting Only Seminars	$750	$2,000
3.	Biennial School Licensure or Registration (as shown in Annex A)	$500—4,400	$1,000—6,500 plus $500 for each additional $500,000 revenue over $1,000,000 with a cap of $35,000

	Board Activity	Former Fee	Amended Fee
4.	Admission Representatives License	$300	$600
5.	New Program Application	$700	$1,400
6.	Change of Ownership	$1,200	$5,000
7.	New School Orientation	$200	$300
8.	School Site Inspection	$500	$750
9.	Board Directed Site Visit	$500	$750
10.	Board Directed Team Visit	$800	$1,000

For the implementation of the renewal fees in § 73.151(a)(3), schools will receive a reminder 11 weeks prior to the expiration of the license. Those schools that have already received the reminder prior to November 19, 2016, will renew in accordance with the prior fee schedule. Reminders sent following November 19, 2016, will include the new fee structure and the new renewal fees will be required.

Summary of Comments and Responses to Proposed Rulemaking

Notice of proposed rulemaking at 46 Pa.B. 1555 (March 26, 2016), with a 30-day public comment period. The Board received a general comment from the Pennsylvania Association of Private School Administrators acknowledging the need for an increase of fees and stating an appreciation for the Board's work on minimizing the fee amount. Additionally, on May 25, 2016, the Board received the comments from the Independent Regulatory Review Commission (IRRC) regarding: the initial licensing and change of ownership fees; the implementation of the biennial fee for license and registration renewal; the new director seminar fee; the effective date; time frame; and summary of proposed amendments. The Board's responses to IRRC's comments are addressed in a separate comment and response document.

Fiscal Impact and Paperwork Requirements

This final-form rulemaking will not have fiscal impact on the Commonwealth or its political subdivisions and will, as required by law, impose costs upon the private sector sufficient to meet the Commonwealth's expenses in regulating private licensed schools. As a result of this final-form rulemaking, the Board will alter some of its forms to reflect the new fees. This final-form rulemaking does not create additional paperwork for the private sector.

Effective Date

These amendments will become effective upon publication in the *Pennsylvania Bulletin*. The Board's objective is to have the changes to the regulations in effect by December 1, 2016.

Sunset Date

The act requires that the Board monitor its revenue and cost on a biennial basis. Therefore, a sunset date has not been assigned.

Statutory Authority

This final-form rulemaking is authorized under section 10 of the act.

Regulatory Review

Under section 5(a) of the Regulatory Review Act (71 P.S. § 745.5(a)), on March 14, 2016, the Board submitted a copy of the notice of proposed rulemaking, published at 46 Pa.B. 1555, to IRRC and the Chairpersons of the House and Senate Education Committees for review and comment.

Under section 5(c) of the Regulatory Review Act, the Board shall submit to IRRC and the House and Senate Committees copies of comments received during the public comment period, as well as other documents when requested. In preparing the final-form rulemaking, the Board considered all comments from IRRC and the public.

Under section 5.1(j.2) of the Regulatory Review Act (71 P.S. § 745.5a(j.2)), on October 19, 2016, the final-form rulemaking was deemed approved by the House and Senate Committees. Under section 5.1(e) of the Regulatory Review Act, IRRC met on October 20, 2016, and approved the final-form rulemaking.

K. *Findings*

The Board finds that:

(1) Public notice of proposed rulemaking was given under sections 201 and 202 of the act of July 31, 1968 (P.L. 769, No. 240) (45 P.S. §§ 1201 and 1202) and regulations promulgated thereunder, 1 Pa. Code §§ 7.1 and 7.2.

(2) A 30-day public comment period was provided as required by law and all comments were considered.

(3) This final-form rulemaking does not enlarge the purpose of the proposed rulemaking published at 46 Pa.B. 1555.

(4) This final-form rulemaking is necessary and appropriate for administration and enforcement of the authorizing act.

L. *Order*

The Board, acting under the authorizing statutes, orders that:

(a) The regulations of the Board, 22 Pa. Code Chapter 73, are amended by amending § 73.151 to read as set forth in Annex A.

(b) The Coordinating Secretary of the Board shall submit this order and Annex A to the Office of General Counsel and the Office of Attorney General for review and approval as to legality and form, as required by law.

(c) The Coordinating Secretary of the Board shall submit this order and Annex A to IRRC and the House and Senate Committees as required by the Regulatory Review Act (71 P.S. §§ 745.1—745.14).

(d) The Coordinating Secretary of the Board shall certify this order and Annex A and deposit them with the Legislative Reference Bureau as required by law.

(e) This order shall take effect upon publication in the *Pennsylvania Bulletin*.

PATRICIA LANDIS,
Coordinating Secretary

(*Editor's Note*: See 46 Pa.B. 7051 (November 5, 2016) for IRRC's approval order.)

Fiscal Note: Fiscal Note 6-334 remains valid for the final adoption of the subject regulation.

Annex A

TITLE 22. EDUCATION

PART III. STATE BOARD OF PRIVATE LICENSED SCHOOLS

CHAPTER 73. GENERAL PROVISIONS

FEES

§ 73.151. Fees.

(a) *License fees.* The fees for school and admissions representative licenses shall accompany both original and renewal license and registration applications. The fee schedule is:

(1) For an original school license or registration—$7,500. The fee for an original school license or registration includes the user fee for the application for approval of one new program. Each additional new program application submitted with a new license application shall be accompanied by an additional new program approval fee as set forth in subsection (b)(1).

(2) For an original school license or registration of a school that only presents seminars—$2,000.

(3) For a renewal school license or registration—biennial fee based on gross tuition revenue:

Gross Tuition Revenue	*Fee*
$0—4,999	$1,000
$5,000—9,999	$2,000
$10,000—49,999	$2,500
$50,000—99,999	$2,700
$100,000—149,999	$2,800
$150,000—199,999	$3,000
$200,000—249,999	$3,500
$250,000—299,999	$4,000
$300,000—399,999	$4,500
$400,000—499,999	$5,000
$500,000—749,999	$5,500
$750,000—999,999	$6,000
$1,000,000 and over	$6,500 plus $500 for each additional $500,000 in revenue with $35,000 cap

(4) For an admission representative license—$600 annually.

(b) *User fees.* Fees will also be assessed for other services provided by the Board, which services are in addition to the processing and issuance of original or renewal school licenses or registration and admissions representative licenses. These user fees are as follows:

(1) A $1,400 fee shall accompany each application for approval of a new program.

(2) A $5,000 fee shall accompany notification to the Board of a change in ownership of the school.

(3) A $300 fee per participant will be charged for participation in new school orientation seminars.

(4) A $750 fee will be charged for each site inspection of the following types: new school, change in location, expansion of instructional space, temporary relocation, branch facility and remote training facility. This fee shall be paid before commencement of the visit.

(5) The fee for a Board-directed visit is $750 per day if the visit is conducted by staff; $1,000 per day plus team member expenses for a visit conducted by a team with nonstaff members. The fee for a Board-directed visit shall be paid before commencement of the visit.

[Pa.B. Doc. No. 16-1986. Filed for public inspection November 18, 2016, 9:00 a.m.]

Title 49—PROFESSIONAL AND VOCATIONAL STANDARDS

STATE BOARD OF EXAMINERS OF NURSING HOME ADMINISTRATORS

[49 PA. CODE CH. 39]

Notice Requirements

The State Board of Examiners of Nursing Home Administrators (Board) adds §§ 39.92 and 39.93 (relating to reporting of crimes and disciplinary actions; and return of actively suspended or revoked licenses) to read as set forth in Annex A.

Effective Date

This final-form rulemaking will be effective upon publication in the *Pennsylvania Bulletin*.

Statutory Authority

Sections 8.1(b) and 12(a)(4) and (6) of the Nursing Home Administrators License Act (act) (63 P.S. §§ 1108.1(b) and 1112(a)(4) and (6)) authorize the Board to discipline licensees who have been convicted of or plead guilty or nolo contendere to a felony or have been disciplined by the licensing authority of another state, territory or country. Section 9.1 of the act (63 P.S. § 1109.1) requires licensees to notify the Board of disciplinary sanctions by other licensing boards within 90 days of disposition or on biennial renewal applications, whichever is sooner. Additionally, section 13(a.1) of the act (63 P.S. § 1113(a.1)) directs the Board to require a person whose license has been suspended or revoked to return the license in the manner the Board directs.

Background and Purpose

Although the previously cited sections of the act authorize the Board to discipline licensees with felony convictions, the Board's regulations do not require that its licensees report these convictions to the Board in advance of biennial renewal. It may be almost 2 years before the Board first learns of the convictions. To ensure that the Board receives information about these convictions in a timelier manner, the Board adds § 33.92 to expedite the reporting of felony convictions. Because the Board is adding the reporting requirements for felony convictions, the Board finds it prudent to include the reporting requirement for disciplinary sanctions taken by other states against licensees as provided in section 9.1 of the act.

Additionally, although the act directs the Board to require licensees to return suspended and revoked licenses to the Board, there was no requirement that they be returned within a specified time. To ensure that licensees return their licensure documents in a timelier manner, the Board is adding § 39.93 to require their return within 30 days of a voluntary surrender, suspension or revocation.

Summary and Responses to Comments

Notice of proposed rulemaking was published at 44 Pa.B. 5490 (August 16, 2014), with a 30-day public comment period during which the Board did not receive any comments. The Independent Regulatory Review Commission (IRRC) submitted a letter advising that it did not have objections, comments or recommendations. Neither the House Professional Licensure Committee (HPLC) nor the Senate Consumer Protection and Professional Licensure Committee (SCP/PLC) submitted comment.

As there were no comments, objections or recommendations regarding the proposed rulemaking, the Board has not made substantive amendments to this final-form rulemaking. However, the Board is correcting an error made in the publication of the proposed rulemaking pertaining to the use of the legal term of art "disposition in lieu of trial" which is used in section 12(a)(4) of the act and is commonly used in criminal law. See, for example, section 18 of The Controlled Substance, Drug, Device and Cosmetic Act (35 P.S. § 780-118).

Fiscal Impact and Paperwork Requirements

The requirement that licensees report criminal actions and disciplinary sanctions to the Board within 30 and 90 days, respectively, should have a slight fiscal and paperwork impact on the Board and licensees. Currently, licensees report this information on their biennial renewal applications. Under this final-form rulemaking, these reports shall be made sooner, triggering additional paperwork responsibilities for licensees. The Board anticipates that it will see an increase in reports as licensees comply with the regulatory requirement thereby incurring additional enforcement costs.

Sunset Date

The Board continuously monitors the effectiveness of its regulations. Therefore, a sunset date has not been assigned.

Regulatory Review

Under section 5(a) of the Regulatory Review Act (71 P.S. § 745.5(a)), on August 5, 2014, the Board submitted a copy of the notice of proposed rulemaking, published at 44 Pa.B. 5490, to IRRC and the Chairpersons of the HPLC and the SCP/PLC for review and comment.

Under section 5(c) of the Regulatory Review Act, the Board shall submit to IRRC, the HPLC and the SCP/PLC copies of comments received during the public comment period, as well as other documents when requested.

Under section 5.1(j.2) of the Regulatory Review Act (71 P.S. § 745.5a(j.2)), on October 19, 2016, the final-form rulemaking was deemed approved by the HPLC and the SCP/PLC. Under section 5(g) of the Regulatory Review Act, the final-form rulemaking was deemed approved by IRRC effective October 19, 2016.

Additional Information

Additional information may be obtained by writing to Christina Stuckey, Board Administrator, State Board of Examiners of Nursing Home Administrators, P.O. Box 2649, Harrisburg, PA 17105-2649, ST-NHA@pa.gov.

Findings

The Board finds that:

(1) Public notice of proposed rulemaking was given under sections 201 and 202 of the act of July 31, 1968 (P.L. 769, No. 240) (45 P.S. §§ 1201 and 1202) and the regulations promulgated thereunder, 1 Pa. Code §§ 7.1 and 7.2.

(2) A public comment period was provided as required by law and all comments were considered.

(3) This final-form rulemaking is necessary and appropriate for the regulation of nursing home administrators in this Commonwealth.

Order

The Board orders that:

(a) The regulations of the Board, 49 Pa. Code Chapter 39, are amended by adding §§ 39.92 and 39.93 to read as set forth in Annex A.

(b) The Board shall submit a copy of Annex A to the Office of the Attorney General and the Office of General Counsel for approval as required by law.

(c) The Board shall submit this order and Annex A to IRRC, the HPLC and the SCP/PLC as required by law.

(d) The Board shall certify this order and Annex A and shall deposit them with the Legislative Reference Bureau as required by law.

(e) The regulations shall take effect immediately upon publication in the *Pennsylvania Bulletin*.

MARY ANN HEWSTON,
Chairperson

(*Editor's Note*: See 46 Pa.B. 7051 (November 5, 2016) for IRRC's approval order.)

Fiscal Note: Fiscal Note 16A-6217 remains valid for the final adoption of the subject regulations.

Annex A

TITLE 49. PROFESSIONAL AND VOCATIONAL STANDARDS

PART I. DEPARTMENT OF STATE

Subpart A. PROFESSIONAL AND OCCUPATIONAL AFFAIRS

CHAPTER 39. STATE BOARD OF EXAMINERS OF NURSING HOME ADMINISTRATORS

STANDARDS OF PROFESSIONAL PRACTICE AND PROFESSIONAL CONDUCT

§ 39.92. Reporting of crimes and disciplinary actions.

(a) A licensee shall notify the Board of having been convicted of a felony, or having received probation without verdict, disposition in lieu of trial or an Accelerated Rehabilitative Disposition in the disposition of felony charges, within 30 days of the conviction or other disposition, or on the biennial renewal application, whichever is sooner. As used in this section, "convicted" includes a judgment, an admission of guilt or a plea of nolo contendere.

(b) A licensee shall notify the Board of disciplinary action in the nature of a final order taken against the licensee by the licensing authority of another state, territory or country within 90 days of receiving notice of the disciplinary action, or on the biennial renewal application, whichever is sooner.

§ 39.93. Return of actively suspended or revoked licenses.

A licensee who has voluntarily surrendered a license instead of discipline or whose license has been actively suspended or revoked by the Board shall return the surrendered, suspended or revoked license to the Board within 30 days of the action.

[Pa.B. Doc. No. 16-1987. Filed for public inspection November 18, 2016, 9:00 a.m.]

BUREAU OF PROFESSIONAL AND OCCUPATIONAL AFFAIRS

[49 PA. CODE CH. 43b]

Schedule of Civil Penalties—Massage Therapists

The Commissioner of Professional and Occupational Affairs (Commissioner) deletes § 43b.23 and adds § 43b.23a (relating to schedule of civil penalties—massage therapists) to read as set forth in Annex A.

Effective Date

This final-form rulemaking will be effective upon publication in the *Pennsylvania Bulletin*. The schedule of civil penalties will apply to violations that occur on or after the effective date.

Statutory Authority

Section 5(a) of the act of July 2, 1993 (P.L. 345, No. 48) (Act 48) (63 P.S. § 2205(a)) authorizes the Commissioner, after consultation with licensing boards in the Bureau of Professional and Occupational Affairs (Bureau), to promulgate a schedule of civil penalties for violations of the acts or regulations of the licensing boards.

Background and Need for this Final-Form Rulemaking

Act 48 authorizes agents of the Bureau to issue citations and impose civil penalties under schedules adopted by the Commissioner in consultation with the Bureau's boards and commissions. Act 48 citations streamline the disciplinary process by eliminating the need for formal orders to show cause, answers, adjudications and orders, and consent agreements. At the same time, licensees who receive an Act 48 citation retain their due process right to a hearing prior to the imposition of judgment. The use of Act 48 citations has increased steadily since 1996, when the program was first implemented, and they have become an important part of the Bureau's enforcement efforts.

Upon consultation with a representative of the Commissioner, the State Board of Massage Therapy (Board) determined that it should utilize the Act 48 citation process to decrease costs to its licensees and more efficiently conduct its duties. The Board has participated in the Act 48 citation program since 2010, when the Commissioner adopted the statement of policy in § 43b.23 setting forth a schedule of civil penalties for a number of offenses. At this time, the Commissioner and the Board believe it is necessary to promulgate the schedule of civil penalties by regulation and make certain revisions to improve their deterrent effect. To that end, this final-form rulemaking establishes a schedule of civil penalties for four general categories of matters that routinely arise before the Board: cases involving licensure display or improper advertising; cases involving unlicensed individuals holding themselves out as licensed; cases involving individuals practicing while their licenses are lapsed/expired/inactive; and cases involving violations of the continuing education and CPR requirements.

Summary of Comments and the Board's Response

Notice of proposed rulemaking was published at 44 Pa.B. 5487 (August 16, 2014), with a 30-day public comment period. On August 18, 2014, the Commissioner received a comment from Ed Portley, a licensed massage therapist and continuing education provider, who commended the Board for "considering the increase in civil penalties for violations to the massage therapy law. It is my opinion that the previous fees were not much of a deterrent to individuals who find licensure an inconvenience." As a result of the public comment, the Commissioner and the Board reconsidered the proposed rulemaking and determined that it was necessary to increase the civil penalties for unlicensed practice to further enhance the deterrent effect. First, the Commissioner increased the civil penalty for a violation of section 14(a) of the Massage Therapy Law (act) (63 P.S. § 627.14(a)) from $500 to $1,000 for a first offense of holding oneself out as a massage therapist or practicing massage therapy while unlicensed. Likewise, the Commissioner increased the civil penalty for violation of section 14(c) of the act from $500 to $1,000 for a first offense of employing an individual in massage therapy who is not licensed. The Commissioner, in consultation with the Board, reasoned that these two offenses are serious offenses and the civil penalty should be more of a deterrent to individuals who might violate these sections of the act.

Neither the House Professional Licensure Committee (HPLC) nor the Senate Consumer Protection and Public Licensure Committee (SCP/PLC) submitted comments on the proposed rulemaking. However, on October 15, 2014, the Independent Regulatory Review Commission (IRRC) submitted comments to the Commissioner. The first three comments from IRRC related to citations to the act, and the Commissioner made necessary corrections. In addition to the edits suggested by IRRC, the Commissioner added cross-references to section 4(6) of the act (63 P.S. § 627.4) and § 20.32(a) (relating to continuing education hours, maintenance of certificates of completion) to support the civil penalty schedule for failure to complete 24 hours of continuing education courses. The Commissioner and the Board agreed that reference to section 14 of the act was too broad with regard to the violation of holding oneself out as a massage therapist or practicing massage therapy while unlicensed and has limited the statutory provision to section 14(a) of the act. Finally, the Commissioner and the Board agree that section 14(b) of the act is not relevant to the offense of holding oneself out as a licensed massage therapist while one's license is expired. Section 14(b) of the act expressly permits one whose license is maintained in inactive status to use various titles or otherwise hold oneself out as a massage therapist. A person whose license is expired is similarly situated as one whose license is inactive. Therefore, the Commissioner, in consultation with the Board, deleted the proposed civil penalty from this final-form rulemaking.

In its last comment, IRRC noted that section 14(e) of the act describes three conditions in the requirement to practice with "a valid, unexpired, unrevoked and unsuspended license," while the proposed rulemaking only set forth a civil penalty for practicing on an expired license. IRRC suggested that all three license statuses be addressed in the schedule. The Board and the Commissioner chose not to establish a schedule of civil penalties for practicing on a revoked or suspended license because these are more egregious offenses than practicing on an expired license, which may have occurred due to an oversight. Under section 5(a) of Act 48, the maximum civil penalty that may be imposed by citation is only $1,000, while the maximum civil penalty that may be imposed by the Board in a formal disciplinary proceeding is $10,000 under section 5(b)(4) of Act 48. In addition, the Board may wish to take other disciplinary or corrective actions that are not possible under the citation process when an individual practices on a revoked or suspended license. An Act 48 civil penalty schedule is only proper for a violation that the Board would typically address through a monetary civil penalty alone. However, the Commissioner added cross-references to § 20.31(b) and (i) (relating to expiration, renewal and reactivation of license) as additional support for this civil penalty because these regulations expressly prohibit practice when a license has not been renewed and authorize disciplinary action for an individual who practices massage therapy on an inactive or expired license. In addition, upon review the Commissioner realized that the schedule of civil penalties for this violation omitted certain time periods. As proposed, the penalty for practicing on a lapsed license from 0—12 months would be $250 and for practicing from 13—18 months would be $500. However, practice for a period between 12 and 13 months was inadvertently omitted from the schedule. Likewise, there is no place in the schedule for violations of between 18 and 19 months. Therefore, the Commissioner revised the schedule to clearly incorporate all possible time periods.

Description of Amendments to this Final-Form Rulemaking

The Commissioner revised the schedule to include the appropriate legal citation to the section of the act under which the offense of "[f]ailure to hold current certification to administer CPR" would occur. The section was previously cited as "63 P.S. § 627.6(b)(i)" and has been corrected to "§ 627.6(b)(1)(i)."

The Commissioner also revised the relevant legal citation relating to "[f]ailure to complete 24 hours of continuing education courses" to reflect the correct citation to "63 P.S. §§ 627.6(b)(1)(ii) and 627.4(6)" and to include the additional cross-reference to § 20.32(a) for further clarity.

The citation for the offense of "[h]olding oneself out as a massage therapist or practicing massage therapy while unlicensed" is revised to provide a more specific citation to section 14(a) of the act, rather than section 14 of the act. The schedule of civil penalties for this violation was also revised to provide for a higher civil penalty of $1,000 for a first offense, rather than $500 as proposed. This revision is based on the public comment and Board discussion regarding the need for the civil penalties to be high enough to result in a deterrent effect on those individuals who find licensure to be an inconvenience.

The schedule of civil penalties was revised to delete the violation for "[h]olding oneself out as a licensed massage therapist while license is expired" because section 14(b) of the act expressly permits an individual whose license is inactive to continue to use various titles or otherwise hold out that one is licensed as a massage therapist. Individuals whose licenses are expired are similarly situated as those whose licenses are maintained in inactive status. Therefore, the Commissioner deleted the proposed civil penalty from the schedule.

The Commissioner revised the civil penalty for a first offense violation of "[e]mploying an individual in massage therapy who is not licensed" from $500 to $1,000. This revision is based on the public comment and Board discussion regarding the need for the civil penalties to be high enough to have a deterrent effect.

Finally, the Commissioner revised the schedule relating to "[p]racticing massage therapy on an expired license" to include practicing massage therapy on an inactive license and added the appropriate citation to § 20.31(i). As proposed, there was not a specific statement that would have allowed for a citation for practice on an inactive license. Inasmuch as practicing on an inactive license is akin to practicing on an expired license, the final-form rulemaking has been revised to cover both situations. Otherwise, practicing on an expired license would result in a citation, while practicing on an inactive license would result in more costly formal disciplinary proceedings. As previously noted, the Commissioner declines to include practicing on a suspended or revoked license in this schedule because those offenses are more appropriately resolved by the Board through formal disciplinary proceedings. In addition, the schedule related to this offense was revised to close inadvertent loopholes created by omitting time frames between 12 and 13 months and between 18 and 19 months from the schedule.

Fiscal Impact and Paperwork Requirements

This final-form rulemaking does not have adverse fiscal impact on the Commonwealth or its political subdivisions, and will reduce the paperwork requirements for the Commonwealth and the regulated community by eliminating the need for orders to show cause, answers, consent agreements and adjudications/orders for those violations subject to the Act 48 citation process. The only fiscal impact of would be borne by persons who violate the act or regulations of the Board and are subject to the civil penalties imposed by the new schedule.

Sunset Date

The Board, the Bureau and the Commissioner continually monitor the effectiveness of regulations affecting their operations. As a result, a sunset date has not been assigned.

Regulatory Review

Under section 5(a) of the Regulatory Review Act (71 P.S. § 745.5(a)), on August 5, 2014, the Commissioner submitted a copy of the notice of proposed rulemaking, published at 44 Pa.B. 5487, to IRRC and the Chairpersons of the HPLC and the SCP/PLC for review and comment.

Under section 5(c) of the Regulatory Review Act, the Commissioner shall submit to IRRC, the HPLC and the SCP/PLC copies of comments received during the public comment period, as well as other documents when requested. In preparing the final-form rulemaking, the Commissioner considered all comments from IRRC and the public.

Under section 5.1(j.2) of the Regulatory Review Act (71 P.S. § 745.5a(j.2)), on October 19, 2016, the final-form rulemaking was deemed approved by the HPLC and the SCP/PLC. Under section 5.1(e) of the Regulatory Review Act, IRRC met on October 20, 2016, and approved the final-form rulemaking.

Contact Person

Further information may be obtained by contacting Carol Niner, Board Administrator, State Board of Massage Therapy, P.O. Box 2649, Harrisburg, PA 17105-2649, RA-MASSAGETHERAPY@PA.GOV.

Findings

The Commissioner finds that:

(1) Public notice of proposed rulemaking was given under sections 201 and 202 of the act of July 31, 1968 (P.L. 769, No. 240) (45 P.S. §§ 1201 and 1202) and the regulations promulgated thereunder, 1 Pa. Code §§ 7.1 and 7.2.

(2) A public comment period was provided as required by law and only one public comment was received.

(3) The amendments to this final-form rulemaking do not enlarge the purpose of the proposed rulemaking published at 44 Pa.B. 5487.

(4) This final-form rulemaking is necessary and appropriate for administering and enforcing the authorizing act identified in this preamble.

Order

The Commissioner, acting under the authority of Act 48, orders that:

(a) The regulations of the Commissioner, 49 Pa. Code Chapter 43b, are amended by adding § 43b.23a and deleting § 43b.23 to read as set forth in Annex A.

(b) The Commissioner shall submit this order and Annex A to the Office of General Counsel and the Office of Attorney General as required by law.

(c) The Commissioner shall submit this order and Annex A to IRRC, the HPLC and the SCP/PLC as required by law.

(d) The Commissioner shall certify this order and Annex A and deposit them with the Legislative Reference Bureau as required by law.

(e) This order shall take effect on publication in the *Pennsylvania Bulletin*.

IAN J. HARLOW,
Commissioner

(*Editor's Note*: See 46 Pa.B. 7051 (November 5, 2016) for IRRC's approval order.)

Fiscal Note: Fiscal Note 16A-723 remains valid for the final adoption of the subject regulations.

Annex A

TITLE 49. PROFESSIONAL AND VOCATIONAL STANDARDS

PART I. DEPARTMENT OF STATE

Subpart A. PROFESSIONAL AND OCCUPATIONAL AFFAIRS

CHAPTER 43b. COMMISSIONER OF PROFESSIONAL AND OCCUPATIONAL AFFAIRS

SCHEDULE OF CIVIL PENALTIES, GUIDELINES FOR IMPOSITION OF CIVIL PENALTIES AND PROCEDURES FOR APPEAL

§ 43b.23. (Reserved).

§ 43b.23a. Schedule of civil penalties—massage therapists.

STATE BOARD OF MASSAGE THERAPY

Violation under 63 P.S.	*Violation under 49 Pa. Code*	*Title/Description*	*Civil Penalty*
	Section 20.42(a)(14)	Failure to display current license or wallet card.	1st offense—$250 2nd and subsequent offenses—$500
	Section 20.42(a)(15)	Failure to include massage therapy license number in advertisements.	1st offense—$250 2nd and subsequent offenses—$500
	Section 20.42(a)(16)	Failure to display name and title.	1st offense—$250 2nd and subsequent offenses—$500
Section 627.6(b)(1)(i)		Failure to hold current certification to administer CPR.	1st offense—$250 2nd offense—$500 Subsequent offense—formal action
Sections 627.6(b)(1)(ii) and 627.4(6)	Section 20.32(a)	Failure to complete 24 hours of continuing education courses approved by the Board during the 24 months preceding license renewal.	1st offense—$100 per credit hour up to 10 credit hours More than 10 credit hours—formal action 2nd and subsequent offenses—formal action
Section 627.14(a)		Holding oneself out as a massage therapist or practicing massage therapy while unlicensed.	1st offense—$1,000 2nd and subsequent offenses—formal action
Section 627.14(c)		Employing an individual in massage therapy who is not licensed.	1st offense—$1,000 2nd and subsequent offenses—formal action

Violation under 63 P.S.	*Violation under 49 Pa. Code*	*Title/Description*	*Civil Penalty*
Section 627.14(d)		A business utilizing the words massage, massage therapist, massage practitioner, masseur, masseuse, myotherapist or any derivative of these terms or abbreviations, unless the services of the business are provided by licensees.	1st offense—$500 2nd and subsequent offenses—formal action
Section 627.14(e)	Section 20.31(b) and (i)	Practicing massage therapy on an expired or inactive license.	1st offense—12 months or less—$250 More than 12 months but no more than 18 months—$500 More than 18 months but no more than 24 months—$1,000 More than 24 months—formal action 2nd offense—12 months or less—$500 More than 12 months but no more than 18 months—$1,000 More than 18 months—formal action Subsequent offenses—formal action

[Pa.B. Doc. No. 16-1988. Filed for public inspection November 18, 2016, 9:00 a.m.]

Title 52—PUBLIC UTILITIES

PENNSYLVANIA PUBLIC UTILITY COMMISSION

[52 PA. CODE CH. 75]

[L-2014-2404361]

Implementation of the Alternative Energy Portfolio Standards Act of 2004

The Pennsylvania Public Utility Commission (Commission), on June 9, 2016, adopted an amended final rulemaking order amending existing regulations to comply with the act of July 17, 2007 (P.L. 114, No. 35) (Act 35 of 2007) and the act of October 15, 2008 (P.L. 1592, No. 129) (Act 129 of 2008), and to clarify issues of law, administrative procedure and policy.

Executive Summary

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

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

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

The Commission has previously implemented rulemakings to implement the AEPS Act and its subsequent legislative amendments. Now, the Commission 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.

Public Meeting held
October 27, 2016

Commissioners Present: Gladys M. Brown, Chairperson, statement follows; Andrew G. Place, Vice Chairperson; John F. Coleman, Jr.; Robert F. Powelson; David W. Sweet

Implementation of the Alternative Energy Portfolio Standards Act of 2004; L-2014-2404361

Second Amended Final Rulemaking Order

The Commission is charged with carrying out the provisions of the Alternative Energy Portfolio Standards Act of 2004 (the "AEPS Act"), 73 P.S. § 1648.1, et seq. This obligation includes the adoption of any regulations necessary for its implementation and enforcement. The Commission has promulgated regulations pertaining to the net metering, interconnection and portfolio standard provisions of the AEPS Act.

Based on our experience to date in implementing the current regulations, the Commission finds that it is necessary to update and revise these regulations to comply with Act 129 of 2008, and Act 35 of 2007, and to clarify certain issues of law, administrative procedure and policy. The Commission has received and reviewed numerous public comments and is issuing final rules, as amended herein, based on the further comments submitted to and concerns expressed by the Independent Regulatory Review Commission (IRRC) and the Office of Attorney General (OAG). In its first disapproval order, the IRRC determined that approval of the rulemaking was not in the public interest. Specifically, the IRRC noted that Section 75.13(a)(3) of the proposed final-form rulemaking would have required alternative energy systems to be sized to generate no more than 200% of the customer-generator's annual electric consumption. IRRC determined that the Commission does not have the statutory authority to impose the limit in § 75.13(a)(3) of the final-form regulation. IRRC also stated that if the Commission decides to proceed with this rulemaking by deleting the limit on net metering subsidies included in § 75.13(a)(3) of the final-form regulation, it should ensure that other provisions of the regulation do not limit a customer-generator's ability to net meter excess generation it produces.

Upon consideration of the IRRC's concerns as outlined in its June 2, 2016 Order and the public comments submitted to IRRC regarding this rulemaking, the Commission modified the final-form regulations by removing any reference to non-statutory limits to a customer-generator's ability to net meter excess generation it produces in the Amended Final Rulemaking Order adopted and entered on June 9, 2016 at this Docket. Specifically, the Commission removed the proposed Section 75.13(a)(3) and the reference to that section in the definition of utility. This Commission found that it was 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 procedures and policy. The final-form regulations, modified as requested by IRRC, will continue to meet this need.

As explained more fully below, the Commission subsequently resubmitted the final-form regulations, as modified by the June 9, 2016 order, to IRRC, which again disapproved of the regulations. IRRC issued its second disapproval order on July 12, 2016, in which it found that the Commission's deletion of 75.13(a)(3) and the revised definition of "utility" created an unclear and ambiguous regulation and delivered it to the Legislative standing committees on the same day. Neither Committee reported a concurrent resolution on the final-form regulations as of July 26, 2016, accordingly, the Committees were deemed to have approved the final-form regulations in accordance with 71 P.S. § 745.7(d).

On August 11, 2016, the Commission delivered the final-form regulations to the OAG for form and legality review pursuant to the Commonwealth Attorneys Act at 71 P.S. § 732-204(b). On October 5, 2016, the OAG directed the Commission to change the definition of "utility" in Section 75.1 as prescribed by the OAG. Upon consideration of the direction of OAG to modify the definition of "utility" the Commission has modified the final-form regulations by incorporating the changes to the definition of "utility" in Section 75.1 as directed by the OAG. The Commission has also provided in this Order more explanation on the independent load requirement based on the concerns raised by the IRRC during its June 30, 2016 public meeting.

This 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 procedures and policy. The final-form regulations, modified as requested by IRRC in its initial disapproval order and as directed by the OAG, will continue to meet this need. As such, the Commission has determined that it will proceed in accordance with Section 7(d) of the Regulatory Review Act, 71 P.S. § 745.7(d), to adopt and promulgate amended final-form regulations addressing the concerns expressed by IRRC in its initial disapproval order and the OAG.

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.

The Commission adopted the Final Rulemaking Order on February 11, 2016, that adopted the revisions to its regulations pertaining to the alternative energy portfolio standard obligation, and its provisions for net metering and interconnection. See Implementation of the Alternative Energy Portfolio Standards Act of 2004, Final Rulemaking Order, Docket No. L-2014-2404361 (Order entered February 11, 2016). The Commission submitted the final-form regulations to the IRRC and the Legislative oversight Committees on March 22, 2016.

Comments were submitted to IRRC by Representatives Greg Vitali and Peter J. Daley, II; Senator Robert M. Tomlinson; Crayola, Inc.; DCIDA; DEP; DOJ; Duquesne; East Lycoming School District; Farm Bureau; FirstEnergy; Granger; LCSWMA; Lego V; Lehigh County Authority; Larry Moyer; PECO; PSU; PWIA; PennFuture, Clean Air Council, Reinvestment Fund, MAREA, Sierra Club, Environmental Defense Fund, SUNWPA, Environmental Entrepreneurs, and Pennsylvania Solar Energy Industries Association (Solar Energy and Environmental Advocates); SRECTrade; Sunrise; SUNWPA; and Turkey Hill Dairy.

The IRRC held a public meeting to review the final-form regulations on May 19, 2016, during which Robert C. Altenburg (PennFuture), David N. Hommrich (Sunrise), Larry Moyer and Mark Hammond testified. At the May 19, 2016 public meeting, the IRRC disapproved the final-form regulations and issued its Order on June 2, 2016.

Upon consideration of IRRC's concerns as outlined in the June 2, 2016 disapproval Order, and comments submitted to IRRC, the Commission, on June 9, 2016, issued an Amended Final Rulemaking Order that adopted modified final-form regulations that removed the non-statutory limits on a customer-generator's ability to net meter excess generation it produces. Specifically, the Commission removed § 75.13(a)(3) and the reference to that section in the definition of utility.

The Amended Final Rulemaking Order was delivered to IRRC and the Legislative oversight Committees on June 13, 2016 in accordance with 71 P.S. § 745.7(c). Following the submission to IRRC, IRRC staff contacted Commission staff informing Commission Staff that the format of the modified final-form regulations was not in compliance with § 311.4 of IRRC's regulations. On June 21, 2016, Law Bureau sent a letter to IRRC Chairman Bedwick with a copy of the revised pages of the modified final-form regulation in the corrected format to illustrate the changes. On June 22, 2016, IRRC Chairman Bedwick sent a letter to Law Bureau noting that the June 21, 2016 letter did not formally amend the final-form regulations, which could only be accomplished with a withdrawal and resubmittal by July 12, 2016.

Comments critical of the amended final-form regulations were submitted to IRRC by several interested parties, including Senator Charles T. McIlhinney, Jr. IRRC held a public meeting to review the modified final-form regulations on June 30, 2016, during which IRRC disapproved the modified final-form regulations. IRRC issued its second disapproval Order on July 12, 2016, in which it found that the Commission's deletion of 75.13(a)(3) and the revised definition of "utility" created an unclear and ambiguous regulation. In addition, IRRC stated that they were not convinced of the need for all provisions of this rulemaking, noting that while the limit was deleted from the rulemaking, other provisions that limit a customer-generator's ability to net meter remain. The IRRC order failed to identify which provisions it believes establishes such a limit. Finally, IRRC determined that the revised final-form regulations did not comply with IRRC's regulation at 1 Pa. Code § 311.4 (report for a disapproved regulation submitted with revisions). For these reasons, IRRC found that promulgation of this regulation was not in the public interest.

IRRC issued its second disapproval order on July 12, 2016, in which it found that the Commission's deletion of 75.13(a)(3) and the revised definition of "utility" created an unclear and ambiguous regulation and delivered its order to the Legislative standing committees on the same day. Neither Committee reported a concurrent resolution on the final-form regulations as of July 26, 2016: accordingly, the Committees were deemed to have approved the final-form regulations in accordance with 71 P.S. § 745.7(d).

On August 11, 2016, the Commission delivered the final-form regulations to the OAG for form and legality review pursuant to the Commonwealth Attorneys Act at 71 P.S. § 732-204(b). On October 5, 2016, upon its review, the OAG directed the Commission to change the definition of "utility" in Section 75.1 as prescribed by the OAG.

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, utility, 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

A. *IRRC Disapproval Orders*

In its initial disapproval order, the IRRC determined that approval of the rulemaking was not in the public interest. The IRRC found that the Commission did not have the statutory authority in regard to certain elements of the rulemaking, and was in violation of Section 5.2(a) of the Regulatory Review Act (RRA). 71 P.S. § 745b(a). Specifically, the IRRC stated that Section 75.13(a)(3) of the proposed rulemaking would have required alternative energy systems to be "sized to generate no more than 110% of the customer-generator's annual electric consumption" and that the Commission increased the percentage from 110% to 200% in the final-form rulemaking. IRRC determined, based on its review of the Commission's written responses to IRRC's comments and the statements presented at the meeting of May 19, 2016 by interested parties, that the Commission does not have the statutory authority to impose the limit in § 75.13(a)(3) of the final-form regulation. IRRC also stated that if the

Commission decides to proceed with this rulemaking by deleting the limit on net metering subsidies included in § 75.13(a)(3) of the final-form regulation, it should ensure that other provisions of the regulation do not limit a customer-generator's ability to net meter excess generation it produces. IRRC Order at 1-2.

IRRC also found that the rulemaking was not in the public interest relating to the RRA criterion of need. 71 P.S. § 745b(b)(3)(iii). IRRC noted that in its comments to the proposed rulemaking it stated that the Commission had not established the overall need for the changes being offered. In response to Question 10 of the Regulatory Analysis Form submitted with the final-form regulation, the purpose of the limit in § 75.13(a)(3) "is to avoid having default service customers pay substantial net metering subsidies to merchant scale alternative energy systems." After review of this information, IRRC found that the Commission has not definitively quantified what the substantial net metering costs will be to other customers. In addition, IRRC noted that during the public meeting, the Commission stated that over-sized systems are not currently a problem in the Commonwealth, but could be in the future. Based on these responses, the IRRC found that the Commission had not established the compelling need for this rulemaking. IRRC Order at 3.

The final reason the IRRC found the rulemaking was not in the public interest relates to the RRA criteria of whether the regulation represents a policy decision of such a substantial nature that it requires legislative review. 71 P.S. § 745b(b)(4). IRRC stated that its comments noted that the implementation of the proposed limits on net metering subsidies could potentially curtail the development of alternative energy in the Commonwealth in conflict with the AEPS Act. IRRC further commented that any deviation from the intent of the AEPS Act would represent a policy decision that requires legislative review and encouraged the Commission to work closely with the members of the General Assembly and the designated standing committees to ensure the final-form regulation was within the scope of the Commission's granted regulatory authority. IRRC goes on to state that if the Commission continues to believe that some customer-generators that produce excess energy are causing economic harm to default service customers, IRRC encouraged the Commission to consult with the legislature to achieve a statutory remedy to this problem. IRRC Order at 3.

Upon consideration of the IRRC's concerns as outlined in its June 2, 2016 Order and the public comments submitted to IRRC regarding this rulemaking, the Commission modified the final-form regulations by removing any reference to non-statutory limits to a customer-generator's ability to net meter excess generation it produces. Specifically, the Commission removed the proposed Section 75.13(a)(3) and the reference to that section in the definition of utility. In addition, the Commission renumbered the remaining subsection under Section 75.13(a) as directed by the IRRC.

In its second disapproval Order, IRRC again found that the rulemaking was not in the public interest for three reasons. First, IRRC found that the deletion of § 75.13(a)(3) and the revised definition of "utility" had created a regulation that was unclear and ambiguous, noting that this violates Section 5.2(b)(3)(ii) of the RRA, 71 P.S. § 745.5b(b)(3)(ii). Second, IRRC found that although the Commission had deleted the limit in § 75.13(a)(3), it believed that other provisions limit a customer-generator's ability to net meter, without identifying what those other provisions were. IRRC again found that a compelling need for all of the provisions of the rulemaking was not established by the Commission, in accordance with Section 5.2(b)(3)(iii) of the RRA, 71 P.S. § 745.5b(b)(3)(iii). Finally, IRRC found that the revised definition of "utility" found under § 75.1 and the revised portion relating to qualifications for net metering in § 75.13(a)(3) were not formatted in compliance with IRRC regulations at 1 Pa. Code § 311.4, violating Section 5.2(b)(6) of the RRA, 71 P.S. § 745.5b(b)(6), that requires compliance with the RRA or the IRRC regulations. IRRC determined that the regulation was not consistent with the statutory criteria of clarity and need and accordingly, found that promulgation of the regulation was not in the public interest.

The Commission disagrees with IRRC that the deletion of § 75.13(a)(3), as requested by IRRC in its initial disapproval Order, or the revised definition of "utility" creates an unclear and ambiguous regulation. However, the Commission can appreciate its concern and, accordingly, as directed by the OAG, the Commission has clarified the definition of "utility" to address those concerns. As to the second set of concerns, the Commission disagrees with IRRC that any of the remaining provisions of the regulations in any way limit a customer-generator's ability to net meter, and IRRC has not identified any specific provision that impose any limits beyond those contained in the AEPS Act.

Finally, as to formatting, this concern is overstated. The Commission staff provided IRRC with the revised pages of the final-form regulations following the IRRC's formatting, which IRRC published on its webpage. Accordingly, IRRC, the designated standing committees and the public were fully informed of the changes being offered by the Commission.

IRRC indicated in its July 12, 2016 disapproval Order cover letter that its disapproval bared the final publication of the regulations for 14 days. IRRC further noted that if either the Senate Consumer Protection and Professional Licensure Committee or House Consumer Affairs Committee reports out a concurrent resolution, the bar would continue until the General Assembly completes its review pursuant to Section 7(d) of the RRA, 71 P.S. § 745.7(d). Section 7(d) of the RRA, 71 P.S. § 745.7(d), further states in part that "[i]f, by the expiration of the 14-calendar-day period, neither committee reports a concurrent resolution, the committees shall be deemed to have approved the final-form or final-omitted regulation, and the agency may promulgate that regulation." As neither the Senate Consumer Protection and Professional Licensure Committee nor House Consumer Affairs Committee reported out a concurrent resolution they are deemed to have approved these final-form regulations and the Commission may proceed with promulgation of the regulations. As previously stated, based on our experience to date in implementing the current regulation, this 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 procedures and policy. The final-form regulations, modified as requested by IRRC in its initial disapproval order and as directed by the OAG, will continue to meet this need.

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

B. *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 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. 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,

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

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

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 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.

[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.

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. *OAG Directed Change*

On August 11, 2016, the Commission submitted the final-form regulations to the OAG for review as to form and legality in accordance with the Commonwealth Attorneys Act at 71 P.S. § 732-204(b). The OAG has 30 days to determine if a "regulation is in improper form, not statutorily authorized or unconstitutional." Id. The Commission may revise the regulation to meet the objections of the OAG. Id. If an agency disagrees with the OAG objection, "it may promulgate the rule or regulation with or without the revisions and shall publish with it a copy of the Attorney General's objections." Id. However, the OAG can:

> appeal the decision of the agency by filing a petition for review with the Commonwealth Court in such manner as is provided for appeals from final orders of government agencies pursuant to 42 Pa.C.S. § 763 (relating to direct appeals from government agencies) and may include in the petition a request for a stay or supersedeas of the implementation of the rule or regulation which upon a proper showing shall be granted.

Id.

On September 1, 2016, the OAG sent a memo to Commission staff tolling the thirty-day statutory review period and seeking clarification on the regulations. Commission staff discussed the regulations with OAG staff and on September 1, 2016, provided responses to OAG staff questions. On October 5, 2016, the OAG sent a memo, attached to this Order in Annex B, directing the Commission to amend the definition of "utility" in Section 75.1 to read as follows:

> Utility—a business, person or entity whose primary purpose, character, or nature is the generation, transmission, distribution or sale of electricity at wholesale or retail. 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.

The OAG memo then states that "this regulation is hereby approved for form and legality, contingent upon the adoption of this revised definition by the Commission at a Commission Public Meeting as soon as is practical."

e. *Disposition Of Utility*

To begin with, the Commission finds that the definition of "utility" as modified by the OAG provides further clarity consistent with the original intent of the Commission. In the Notice of Proposed Rulemaking Order, issued on February 20, 2014, the Commission stated that "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." See Implementation of the Alternative Energy Portfolio Standards Act of 2004, Notice of Proposed Rulemaking Order at Docket No. L-2014-2404361, entered February 20, 2014 at 8 (emphasis added).[4] The language OAG directed to include, "a business, person or entity whose primary purpose, character, or nature is. . ." encapsulates the intent of the Commission for the term utility to apply to persons or entities whose primary business is electric generation, transmission, or distribution services, at wholesale or retail. We also find that the phrase "to other persons or entities" is superfluous, as wholesale and retail services by their nature involves other persons or entities. Accordingly, as directed by the OAG, the Commission amends its June 9, 2016, Amended Final Rulemaking Order, at this Docket, by adopting and incorporating these changes to the definition of "utility" in Section 75.13 of the final-form regulations found in Annex A of this order.

As discussed above, the Commission must interpret and apply the definition of customer-generator in a manner

[4] We also note that the same language appears on page 13 of the February 11, 2016, Final Rulemaking Order, and page 17 of the June 9, 2016, Amended Final Rulemaking Order, as well as in Section B.5.a. of this Order.

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 Assembly 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).[5]

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.

We, however, do not find that the definition was intended to be so broad that it would preclude, from

[5] 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.

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. In the February 11, 2016 Final Rulemaking Order, we had revised the definition of utility to exclude owners or operators of an alternative energy system that was 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). However, as the IRRC disapproved of this limitation in its June 2, 2016 Order, we will delete this reference in this amended final rulemaking. We, however, will retain the 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.[6] 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.

[6] 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.

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.

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.

C. *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 relettering 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. The first sentence in the definition of net metering states that it is "[t]he 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. . .is used to offset part or all of the customer-generator's requirements for electricity." The "electricity supplied by an electric utility" is for the "independent load." The second part of this sentence refers to offsetting "part or all of the customer-generator's requirements for electricity," depends upon the existence of independent load, for if there is no independent load, there is no requirement for electricity that would be offset or netted against. 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).

We further note that the existing regulations at 52 Pa. Code § 75.13(c) explicitly require load at the point of interconnection for the generator. Section 75.13(c) states in part the following:

> 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.

52 Pa. Code § 75.13(c). There would be no ability to apply a credit at the meter through which the generating facility supplies electricity to the distribution system if there was no electric load requirement at that meter. This demonstrates that the Commission continues to be consistent and has added this explicit language simply to add precision to the regulations, not to create a new requirement as some have asserted.

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,[7] 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.[8] 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.[9]

i. *Comments*

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

[7] See Net Metering—Use of Third Party Operators, Final Order at 9.

[8] Id. at 10.

[9] 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."

native 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*

Based on IRRC's June 2, 2016 Order and the necessity of having the remaining provisions of this final rulemaking promulgated, we will remove this limitation and the associated subsections and renumber the remaining subsections.

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*

Based on IRRC's June 2, 2016 Order and the necessity of having the remaining provisions of this final rulemaking promulgated, we will remove this limitation and the associated subsections and renumber the remaining subsections.

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*

Based on IRRC's June 2, 2016 Order and the necessity of having the remaining provisions of this final rulemaking promulgated, we will remove this limitation and the associated subsections and renumber the remaining subsections.

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*

Based on IRRC's June 2, 2016 Order and the necessity of having the remaining provisions of this final rulemaking promulgated, we will remove this limitation and the associated subsections and renumber the remaining subsections.

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*

Based on IRRC's June 2, 2016 Order and the necessity of having the remaining provisions of this final rulemaking promulgated, we will remove this limitation and the associated subsections and renumber the remaining subsections.

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. We will, however, renumber this subsection to § 75.13(a)(3) as we are removing the proposed subsection 75.13(a)(3) in response to IRRC's June 2, 2016 Order. Accordingly, we adopt the language in the new Section § 75.13(a)(3) 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. We, however, have renumbered this subsection to § 75.13(a)(4) as we are removing the proposed subsection 75.13(a)(3) in response to IRRC's June 2, 2016 Order.

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. We, however, have renumbered this subsection to § 75.13(a)(5) as we are removing the proposed subsection 75.13(a)(3) in response to IRRC's June 2, 2016 Order.

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 "the 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.

D. *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, noncontiguous parcels of land that were separately metered to measure the load served at each location. The Commission chose to permit the virtual metering of these parcels to achieve the policy objectives of the AEPS Act:

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

[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 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 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

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

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 C.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 recom-

[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.

mends 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 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.

E. *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 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

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

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.

F. *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. As such, 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.

G. *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.

H. *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.

I. *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.

J. *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.

K. *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.

L. *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).

M. *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.

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).

N. *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.

O. *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-2009-2093383 (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

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

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.

Regulatory Review

Under section 5(a) of the Regulatory Review Act (71 P.S. § 745.5(a)), on June 23, 2014, the Commission submitted a copy of the notice of proposed rulemaking, published at 44 Pa.B. 4179, to IRRC and the Chairpersons of the Senate Consumer Protection and Professional Licensure Committee and the House Consumer Affairs Committee for review and comment.

Under section 5(c) of the Regulatory Review Act, the Commission shall submit to IRRC and the House and Senate Committees copies of comments received during the public comment period, as well as other documents when requested. In preparing the final-form rulemaking, the Commission has considered all comments from IRRC, the General Assembly and the public.

Under section 5.1(e) of the Regulatory Review Act (71 P.S. § 745.5a(e)), IRRC met on June 30, 2016, and disapproved the final-form rulemaking. Under section 6(a) of the Regulatory Review Act (71 P.S. § 745.6(a)), IRRC issued its second disapproval order to the Commission and the House and Senate Committees on July 12, 2016.

Neither Committee reported a concurrent resolution on or before July 26, 2016, as provided under section 7(d) of the Regulatory Review Act. Therefore, the House and Senate Committees are deemed to have approved the final-form rulemaking on that date.

The Commission submitted the final-form rulemaking to the Office of Attorney General for review under section 204(b) of the Commonwealth Attorneys Act (71 P.S. § 732-204(b)). Contingent upon adoption of a change directed by the Office of Attorney General, which the Commission has done in its Second Amended Final Rulemaking, this final-form rulemaking was approved for form and legality by the Office of Attorney General on October 5, 2016.

Conclusion

Accordingly, under 66 Pa.C.S. §§ 501, 1501 and 2807(e), sections 1648.7(a) and 1648.3(e)(2) of the Alternative Energy Portfolio Standards Act of 2004 (73 P.S. §§ 1648.7(a) and 1648.3(e)(2)); the act of July 31, 1968 (P.L. 769, No. 240) (45 P.S. §§ 1102—1208), known as the Commonwealth Documents Law, 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 That:

1. The regulations of the Commission, 52 Pa. Code Chapter 75, are amended by adding §§ 75.16, 75.17, 75.71 and 75.72 and amending §§ 75.1, 75.12—75.14, 75.22, 75.31, 75.39, 75.40, 75.51 and 75.61—75.65 to read as set forth in Annex A, with ellipses referring to the existing text of the regulations.

(*Editor's Note*: The proposed amendments to § 75.34 included in the proposed rulemaking have been withdrawn by the Commission.)

2. A copy of this order and Annex be served on the 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.

3. The Law Bureau shall deposit this order, Annex A and Annex B with the Legislative Reference Bureau for publication in the *Pennsylvania Bulletin*.

4. These regulations shall become effective upon publication in the *Pennsylvania Bulletin*.

5. The contact person for technical issues related to this rulemaking is Scott Gebhardt, Bureau of Technical Utility Services, (717) 787-2139. 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.

ROSEMARY CHIAVETTA,
Secretary

(*Editor's Note*: See 46 Pa.B. 4029 (July 23, 2016) for IRRC's disapproval order.)

Fiscal Note: Fiscal Note 57-304 remains valid for the final adoption of the subject regulations.

Statement of Chairperson Gladys M. Brown

Today, the Commission revisits the revisions to our net metering and interconnection regulations pursuant to the Alternative Energy Portfolio Standards Act (AEPS). The revision to the definition of "utility" included in this iteration of the regulations is an effort to accommodate the concerns voiced by the Independent Regulatory Review Commission, the office of Attorney General, and stakeholders in the rulemaking process. I believe that the revised definition of utility is consistent with the AEPS and is in the public interest.

I also wish to state that the revisions made to these net metering regulations are not an attempt to address any court challenges currently being made regarding net metering tariffs or rules for the very reason that they are "ongoing" and not yet resolved.

GLADYS M. BROWN,
Chairperson

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 (relating to additional alternative energy sources).

Aggregator—A person or entity that maintains a contract with multiple individual alternative energy system 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:

(i) Solar photovoltaic or other solar electric energy.

(ii) Solar thermal energy.

(iii) Wind power.

(iv) Large-scale hydropower, which means the production of electric power by harnessing the hydroelectric potential of moving water impoundments, including pumped storage that does not meet the requirements of low-impact hydropower.

(v) Low-impact hydropower consisting of any technology that produces electric power and that harnesses the hydroelectric potential of moving water impoundments 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:

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

(II) Meets the certification standards established by the Low Impact Hydropower Institute and American Rivers, Inc., or their successors.

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

(IV) Protects against erosion.

(V) Protects cultural and historic resources.

(VI) Was completed after the effective date of the 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.

(ix) Fuel cells, which means any electrochemical device that converts chemical energy in a hydrogen-rich fuel directly into electricity, heat and water without combustion.

(x) Waste coal, which includes the combustion of waste coal in facilities in which the waste coal was disposed or abandoned prior to July 31, 1982, or disposed of thereafter in a permitted coal refuse disposal site regardless of when disposed of, and used to generate electricity, or other waste coal combustion meeting alternate eligibility requirements established by regulation. Facilities combusting waste coal shall use at a minimum a combined fluidized bed boiler and be outfitted with a limestone injection system and a fabric filter particulate removal system. Alternative energy credits shall be calculated based upon the proportion of waste coal utilized to produce electricity at the facility.

(xi) Coal mine methane, which means methane gas emitting from abandoned or working coal mines.

(xii) Demand-side management consisting of the management of customer consumption of electricity or the demand for electricity through the implementation of:

(A) Energy efficient technologies, management practices or other strategies in residential, commercial, industrial, institutional and government customers that shift electric load from periods of higher demand to periods of lower demand.

(B) Load management or demand response technologies, management practices or other strategies in residential, commercial, industrial, institutional and government customers that shift electric load from periods of higher demand to periods of lower demand.

(C) Industrial by-product technologies consisting of the use of a by-product from an industrial process, including reuse of energy from exhaust gases or other manufacturing by-products that are used in the direct production of electricity at the facility of a customer.

(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.

Alternative energy system—A facility or energy system that uses a form of alternative energy source to generate electricity and delivers the electricity it generates to the distribution system of an EDC or to the transmission system operated by a regional transmission organization.

Competitive transition charge—A nonbypassable charge applied to the bill of every customer accessing the transmission or distribution network which charge is designed to recover an electric utility's transition or stranded costs.

Cost recovery period—The longer of:

(i) The period during which competitive transition charges under 66 Pa.C.S. § 2808 (relating to competitive transition charge) or intangible transition charges under 66 Pa.C.S. § 2812 (relating to approval of transition bonds) are recovered.

(ii) The period during which an EDC operates under a Commission-approved generation rate plan that has been approved prior to or within 1 year of February 28, 2005, but the cost-recovery period under the act may not extend beyond December 31, 2010.

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.

EDC—Electric distribution company—The public utility providing facilities for the jurisdictional transmission and distribution of electricity to retail customers, except building or facility owners/operators that manage the internal distribution system serving the building or facility and that supply electric power and other related electric power services to occupants of the building or facility.

EGS—Electric generation supplier—

(i) A person or corporation, including municipal corporations which choose to provide service outside their municipal limits except to the extent provided prior to December 16, 2006, brokers and marketers, aggregators or any other entities, that sells to end-use customers electricity or related services utilizing the jurisdictional transmission and distribution facilities of an EDC or that purchases, brokers, arranges or markets electricity or related services for sale to end-use customers utilizing the jurisdictional transmission and distribution facilities of an EDC.

(ii) The term excludes building or facility owner/operators that manage the internal distribution system serving the building or facility and that supply electric power and other related power services to occupants of the building or facility.

(iii) The term excludes electric cooperative corporations except as provided in 15 Pa.C.S. Chapter 74 (relating to generation choice for customers of electric cooperatives).

Force majeure—

(i) Upon its own initiative or upon a request of an EDC or an EGS, the Commission, within 60 days, will determine if alternative energy resources are reasonably available in the marketplace in sufficient quantities for the EDCs and the EGSs to meet their obligations for that reporting period under the act. In making this determination, the Commission will consider whether EDCs or EGSs have made a good faith effort to acquire sufficient alternative energy to comply with their obligations. Evidence of good faith efforts include:

(A) Banking alternative energy credits during transition periods.

(B) Seeking alternative energy credits through competitive solicitations.

(C) Seeking to procure alternative energy credits or alternative energy through long-term contracts.

(D) Other competent evidence the commission credits as demonstrating a good faith effort.

(ii) In further making its determination, the Commission will assess the availability of alternative energy credits in the Generation Attributes Tracking System or its successor, and the availability of alternative energy credits generally in this Commonwealth and other jurisdictions in the PJM Interconnection, LLC regional transmission organization or its successor. The Commission may also require solicitations for alternative energy credits as part of default service before requests of force majeure may be made.

(iii) If the Commission determines that alternative energy resources are not reasonably available in sufficient quantities in the marketplace for the EDCs and EGSs to meet their obligations under the act, the Commission will modify the underlying obligation of the EDC or EGS or recommend to the General Assembly that the underlying obligation be eliminated. Commission modification of the EDC or EGS obligations under the act will be for that compliance period only. Commission modification may not automatically reduce the obligation for subsequent compliance years.

(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 energycredits 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—An emergency condition as defined in the PJM Interconnection, LLC Open Access Transmission Tariff or successor document.

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 distribution system have DR and critical infrastructure load in a combination so as to give the EDC 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.

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 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.

Reporting period—The 12-month period from June 1 through May 31. A reporting year shall be numbered according to the calendar year in which it begins and ends.

Retail electric customer—

(i) A direct purchaser of electric power.

(ii) The term excludes an occupant of a building or facility where the following apply:

(A) The owners/operators manage the internal distribution system serving the building or facility and supply electric power and other related power services to occupants of the building or facility.

(B) The owners/operators are direct purchasers of electric power.

(C) The occupants are not direct purchasers.

Stranded costs—An electric utility's known and measurable net electric generation-related costs, determined on a net present value basis over the life of the asset or liability as part of its restructuring plan, which traditionally would be recoverable under a regulated environment but which may not be recoverable in a competitive electric generation market and which the Commission determines will remain following mitigation by the electric utility.

Tier I alternative energy source—Energy derived from:

(i) Solar photovoltaic and solar thermal energy.

(ii) Wind power.

(iii) Low-impact hydropower.

(iv) Geothermal energy.

(v) Biologically derived methane gas.

(vi) Fuel cells.

(vii) Biomass energy.

(viii) Coal mine methane.

Tier II alternative energy source—Energy derived from:

(i) Waste coal.

(ii) Distributed generation systems.

(iii) Demand-side management.

(iv) Large-scale hydropower.

(v) Municipal solid waste.

(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—

(i) A business, person or entity whose primary purpose, character or nature is the generation, transmission, distribution or sale of electricity at wholesale or retail.

(ii) The term excludes building or facility owners or operators that manage the internal distribution system serving the 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:

Base year—For customer-generators who initiated self generation on or after January 1, 1999, the base year will be the immediate prior calendar year; for all other customer generators, the base year will be 1996.

Billing month—The term has the same meaning as set forth in § 56.2 (relating to definitions).

Customer-generator facility—The equipment used by a customer-generator to generate, manage, monitor and deliver electricity to the EDC.

Electric distribution system—That portion of an electric system which delivers electricity from transformation points on the transmission system to points of connection at a customer's premises.

Meter aggregation—The combination of readings from and billing for all meters regardless of rate class on properties owned or leased and operated by a customer-generator for properties located within the service territory of a single EDC. Meter aggregation may be completed through physical or virtual meter aggregation.

Net metering—The means of measuring the difference between the electricity supplied by an electric utility or EGS 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.

Physical meter aggregation—The physical rewiring of all meters regardless of rate class on properties owned or leased and operated by a customer-generator to provide a single point of contact for a single meter to measure electric service for that customer-generator.

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 the same customer-generator and located within 2 miles of the boundaries of the customer-generator's property and within a single 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*—The period of time from June 1 through May 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 have a nameplate capacity of not greater than 50 kW if installed at a residential service location.

(4) The alternative energy system must have a nameplate capacity not larger than 3 MW at other customer service locations, except when the alternative energy system has a nameplate capacity not larger than 5 MW and meets the conditions in § 75.16 (relating to large customer-generators).

(5) An alternative energy system with a nameplate capacity of 500 kW or more must have Commission approval to net 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.

(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 enables 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 under § 54.5 (relating to disclosure statement for residential and small business customers).

(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 supplies more electricity to the electric distribution system than the EDC 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.

(e) At the end of each year, the DSP shall compensate the customer-generator for any remaining excess kilowatt hours generated by the customer-generator that were not previously credited against the customer-generator's usage in prior billing periods at the DSP's price to compare rate.

(f) The credit or compensation terms for excess electricity produced by customer-generators who are customers of EGSs must 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.

(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.

(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.

(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).

(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.

(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.

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

§ 75.14. Meters and metering.

(a) A customer-generator facility used for net metering must be equipped with a single bidirectional meter that can measure and record the flow of electricity in both directions at the same rate. If the customer-generator agrees, a dual meter arrangement may be substituted for a single bidirectional meter.

(b) If the customer-generator's existing electric metering equipment does not meet the requirements in subsection (a), the EDC shall install new metering equipment for the customer-generator at the EDC's expense. Any subsequent metering equipment change necessitated by the customer-generator shall be paid for by the customer-generator.

(c) When the customer-generator intends to take title or transfer title to any alternative energy credits which may be produced by the customer-generator's facility, the customer-generator shall bear the cost of additional net metering equipment required to qualify the alternative energy credits in accordance with the act.

(d) When the customer-generator expressly rejects ownership of alternative energy credits produced by the customer-generator's facility, the EDC may supply additional metering equipment required to qualify the alternative energy credit at the EDC's expense. In those circumstances, the EDC shall take title to any alternative energy credit produced. An EDC shall, prior to taking title to any alternative energy credits produced by a customer-generator, fully inform the customer-generator of the potential value of the alternative energy credits and other options available to the customer-generator for the disposition of those credits. A customer-generator is not prohibited from having a qualified meter service provider install metering equipment for the measurement of generation, or from selling alternative energy credits to a third party other than an EDC.

(e) Virtual meter aggregation on properties owned or leased and operated by 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 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 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) The alternative energy system is able to provide the emergency support consistent with the RTO tariff or agreement.

(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 10 days of an EDC's submission recommending approval. If disapproved, the Bureau of Technical Utility Services will 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.

(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 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 5 MW.

(2) The small generator facility is not subject to the interconnection requirements of an RTO.

(3) The small generator facility is designed to operate in parallel with the electric distribution system.

§ 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 interconnectionrequests 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 5 MW or less.

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

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

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§ 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 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 5 MW or less.

* * * * *

DISPUTE RESOLUTION

§ 75.51. Disputes.

(a) A party shall attempt to resolve all disputes regarding interconnection as provided in this chapter promptly, equitably and in a good faith manner.

(b) When a dispute arises, a party may seek immediate resolution through complaint procedures available through the Commission, or an alternative dispute resolution process approved by the Commission, by providing written notice to the Commission and the other party stating the issues in dispute. Dispute resolution will be conducted in an informal, expeditious manner to reach resolution with minimal costs and delay. When available, dispute resolution may be conducted by phone.

(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.

(a) EDCs and EGSs shall comply with the act through the acquisition of certified alternative energy credits, each of which shall represent one MWh of qualified alternative electric generation or conservation, whether self-generated, purchased along with the electric commodity or separately through a tradable instrument.

(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):

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§ 75.62. Alternative energy system qualification.

(a) An application for alternative energy system status shall be submitted on a form developed and made available by the Commission. A copy of the application form will be made available on the Commission's public Internet domain. An application shall be verified by oath or affirmation as required under § 1.36 (relating to verification).

(b) A completed application and supporting attachments shall be filed with the alternative energy credit program administrator, the Department of Environmental Protection and any other parties that may be designated by the Commission.

(c) A facility, to be qualified for alternative energy system status, shall demonstrate that it is physically located in either:

(1) This Commonwealth.

(2) The control area of an RTO that manages a portion of the electric transmission system in this Commonwealth.

(d) Alternative energy credits derived from alternative energy sources located outside the geographical boundaries of this Commonwealth but within the control area of an RTO that manages the transmission system in any part of this Commonwealth shall only be eligible to meet the compliance requirements of EDCs or EGSs located within the service territory of the same RTO. For purposes of compliance with the act, alternative energy sources located in the control area of the PJM Interconnection, LLC RTO or its successor shall be eligible to fulfill compliance obligations of all Pennsylvania EDCs and EGSs.

(e) A facility, to be qualified for alternative energy system status, shall demonstrate that it generates electricity from or conserves electricity through a Tier I or Tier II alternative energy source.

(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.

(a) An alternative energy credit may be certified by the Commission for each MWh of electricity generated by qualified alternative energy systems on or after February 28, 2005.

(b) An alternative energy credit may be certified by the Commission for each MWh of electricity conserved by qualified alternative energy systems or demand side management on or after November 30, 2004.

(c) An alternative energy credit may not be certified 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.

(d) An alternative energy credit already purchased by individuals, businesses or government bodies that do not have a compliance obligation under the act may not be certified for a MWh of electricity generation or electricity conservation unless the individual, business or government body sells those credits to the EDC or EGS.

(e) When an alternative energy system relies on more than one fuel source or technology, alternative energy credits shall be certified for that portion of the electric generation that is derived from an alternative energy fuel source or technology.

(f) For all alternative energy systems except solar photovoltaic systems with a nameplate capacity of 15 kilowatts or less, alternative energy credit certification shall be verified by metered data obtained from or by one of the following:

(1) An RTO.

(2) The credits registry designated under § 75.70 (relating to alternative energy credit registry).

(3) The administrator designated under § 75.64 (relating to alternative energy credit program administrator).

(g) For solar photovoltaic alternative energy systems with a nameplate capacity of 15 kW or less that are installed or that increase nameplate capacity on or after May 18, 2017, 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 May 18, 2017, 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.

(a) The Commission may select an independent entity to act as a program administrator and perform administrative functions necessary to the implementation of this chapter. If an independent entity is not selected to act as a program administrator, the Commission will perform the functions identified in this section.

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

(1) Distribute, receive and review applications for alternative energy system qualification.

(2) Reject applications that are incomplete or do not adhere to the application instructions.

(3) Determine whether an application satisfies the geographic eligibility standard in § 75.62(c) (relating to alternative energy system qualification) and reject applications that fail this standard.

(4) Qualify applicants for alternative energy system status who have filed a complete application, adhered to application instructions, satisfied the geographic eligibility standard, complied with environmental regulations and utilized an alternative energy fuel source or technology.

(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 reported load, and provide written notice to each EDC and EGS of its compliance 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. The administrator will provide written notice to each EDC and EGS of a final assessment of its compliance status within 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's Bureau of Technical Utility Services within 45 days of the end of 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 reconsideration from actions of the staff).

(f) The Commission may delegate other responsibilities to the program administrator as may be necessary for the implementation of the act.

§ 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'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.

(b) Each EDC and EGS shall be assessed an alternative compliance payment according to the following formula:

(1) For noncompliance with the solar photovoltaic requirements identified in § 75.61, an EDC and EGS shall make an alternative compliance payment equal to the following:

(i) The average market value for solar photovoltaic alternative energy credits sold during the reporting period in the RTO control area where the noncompliance occurred.

(ii) Add to value in subparagraph (i), the levelized up-front rebates received by sellers of solar renewable energy credits (calculated as follows: total amount of rebates paid within the previous 20 years, divided by the total kilowatt capacity for which rebates were given in the previous 20 years, divided by 20 (the useful life of a solar photovoltaic system), multiplied by the percentage of alternative energy used during the reporting period originating from jurisdictions where rebates were given).

(iii) Multiply the value in subparagraph (ii) by 200%.

(2) For noncompliance with all other requirements identified in § 75.61, an EDC and EGS shall make an alternative compliance payment equal to $45 times the number of additional alternative energy credits necessary for compliance in that reporting period.

(3) The costs of alternative compliance payments made under this section may not be recoverable from ratepayers.

(c) EDCs and EGSs shall advise the 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 Bureau of Technical Utility Services will refer the petition to the Commission's Bureau of Investigation and Enforcement for further actions as may be warranted. Failure of an EDC or EGS to respond to the Bureau of Technical Utility Services within 15 days of the issuance of this notice will be deemed an acceptance of the alternative compliance payment determination.

(d) EDCs and EGSs shall send their alternative compliance payments to a special fund designated by the Commission within 30 days of acceptance of their payment determination, or the conclusion of proceedings before the Commission regarding the modification of the level of payment.

(e) Alternative compliance payments shall be made available to the sustainable energy funds established through the Commission's orders entered under 66 Pa.C.S. § 2806(f) (relating to implementation, pilot programs and performance-based rates), under procedures and standards proposed by the Pennsylvania Sustainable Energy Board and approved by the Commission at Docket M-00031715. See 33 Pa.B. 4263 (August 23, 2003).

(f) Alternative compliance payments made available to the sustainable energy funds shall be utilized solely for projects that increase the amount of electric energy generated from alternative energy resources for purposes of compliance with § 75.61.

(g) The Commission may utilize up to 5% of alternative compliance payments made by EDCs and EGSs for administrative expenses directly associated with the implementation of this chapter, including the costs of the program administrator.

§ 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 66 Pa.C.S. § 2814(c) (relating to additional alternative energy sources).

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

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

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

(3) An EDC's or EGS's quarterly MWh retail sales multiplied by the new quarterly nonsolar photovoltaic Tier I requirement (EDC and EGS quarterly MWh × 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 66 Pa.C.S. 2814(a) and (b) 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 November 4.

(2) Second quarter (September, October and November) due by February 4.

(3) Third quarter (December, January and February) due by 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 November 4.

(2) Second quarter (September, October and November) due by the second business day after February 4.

(3) Third quarter (December, January and February) due by the second business day after 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 66 Pa.C.S. § 2814(a) and (b) (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).

Annex B

COMMONWEALTH OF PENNSYLVANIA
OFFICE OF ATTORNEY GENERAL

October 5, 2016

RE: Public Utility Commission Regulation # 57-304

TO: Bohdan R. Pankiw
Chief Counsel
Public Utility Commission

FROM: Amy M. Elliott
Chief Deputy Attorney General
Legal Review Section

This office is in receipt of the Commission's September 29, 2016, response to our September 1, 2016, tolling memorandum. Having reviewed the Commission's correspondence, we hereby direct the Commission to amend the definition of "utility" in Section 75.1 to read as follows:

> Utility—a business, person or entity whose primary purpose, character, or nature is the generation, transmission, distribution or sale of electricity at wholesale or retail. 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.

In consideration of the foregoing, this regulation is hereby approved for form and legality, contingent upon the adoption of this revised definition by the Commission at a Commission Public Meeting as soon as is practical.

Public Utility Commission
52 Pa. Code Ch. 75
Implementation of the Alternative Energy
Portfolio Standards Act of 2004
FINAL FORM

AME:mlm
SR-75554-C1ZW

cc: Leslie A. Lewis Johnson, Esq.

[Pa.B. Doc. No. 16-1989. Filed for public inspection November 18, 2016, 9:00 a.m.]

Title 58—RECREATION

PENNSYLVANIA GAMING CONTROL BOARD

[58 PA. CODE CH. 681a]

21 Baccarat; Table Game Rules of Play

The Pennsylvania Gaming Control Board (Board), under the general authority in 4 Pa.C.S. § 1202(b)(30) (relating to general and specific powers) and the specific authority in 4 Pa.C.S. § 13A02(1) and (2) (relating to regulatory authority), adds Chapter 681a (relating to 21 Baccarat).

Purpose of this Final-Form Rulemaking

This final-form rulemaking adds a new table game to the compliment of games available for play in this Commonwealth.

Explanation

Section 681a.1 (relating to definitions) contains the definitions used throughout Chapter 681a. Section 681a.2 (relating to 21 Baccarat table; physical characteristics) contains the table physical characteristics. Section 681a.3 (relating to cards; number of decks; value of cards) details the number of cards and decks used to play the game. Section 681a.4 (relating to opening of the table for gaming) addresses the opening of the table for gaming. Section 681a.5 (relating to shuffle and cut of the cards) details how the cards are to be shuffled and cut. Section 681a.6 (relating to wagers) outlines the permissible wagers. Section 681a.7 (relating to procedure for dealing the cards; completion of each round of play) addresses how the cards are to be dealt and the round of play is to be completed. Section 681a.8 (relating to payout odds) outlines the permissible payout odds for winning wagers. Section 681a.9 (relating to irregularities) addresses irregularities in play.

In 21 Baccarat, depending on the number of decks used for play of the game, the hold percentage for the optional Tie Wager is either 5.4% or 5.9% and between 5.8% and 8.0% for the optional Bonus Wager.

Comment and Response Summary

Notice of proposed rulemaking was published at 46 Pa.B. 1433 (March 19, 2016). The Board did not receive comments from the regulated community or the Independent Regulatory Review Commission (IRRC) regarding the proposed rulemaking.

Affected Parties

Slot machine licensees may be impacted by this final-form rulemaking as they will have the option to offer another game to patrons at their licensed facilities.

Fiscal Impact

Commonwealth. The Board does not expect that this final-form rulemaking will have a fiscal impact on the Board or other Commonwealth agencies. Updates to Rules Submission forms and internal control procedures will be reviewed by existing Board staff.

Political subdivisions. This final-form rulemaking will not have fiscal impact on political subdivisions of this Commonwealth.

Private sector. This final-form rulemaking will provide certificate holders with additional table game options. If a certificate holder decides to offer 21 Baccarat within the licensed facility, the certificate holder will be required to train their dealers on the rules of play and may need to purchase new equipment. Costs incurred to train employees or purchase/lease equipment should be offset by the proceeds of gaming.

General public. This final-form rulemaking will not have fiscal impact on the general public.

Paperwork Requirements

If a certificate holder selects different options for the play of table games, the certificate holder will be required to submit an updated Rules Submission form reflecting the changes. These forms are available and submitted to Board staff electronically.

Effective Date

This final-form rulemaking will become effective upon publication in the *Pennsylvania Bulletin*.

Regulatory Review

Under section 5(a) of the Regulatory Review Act (71 P.S. § 745.5(a)), on March 9, 2016, the Board submitted a copy of the notice of proposed rulemaking, published at 46 Pa.B. 1433, to IRRC and the Chairpersons of the House Gaming Oversight Committee and the Senate Community, Economic and Recreational Development Committee for review and comment.

Under section 5(c) of the Regulatory Review Act, the Board shall submit to IRRC and the House and Senate Committees copies of comments received during the public comment period, as well as other documents when requested.

Under section 5.1(j.2) of the Regulatory Review Act (71 P.S. § 745.5a(j.2)), on October 19, 2016, this final-form rulemaking was deemed approved by the House and Senate Committees. Under section 5(g) of the Regulatory Review Act, this final-form rulemaking was deemed approved by IRRC effective October 19, 2016.

Findings

The Board finds that:

(1) Public notice of intention to adopt these amendments was given under sections 201 and 202 of the act of July 31, 1968 (P.L. 769, No. 240) (45 P.S. §§ 1201 and 1202) and the regulations thereunder, 1 Pa. Code §§ 7.1 and 7.2.

(2) This final-form rulemaking is necessary and appropriate for the administration and enforcement of 4 Pa.C.S. Part II (relating to gaming).

Order

The Board, acting under 4 Pa.C.S. Part II, orders that:

(1) The regulations of the Board, 58 Pa. Code, are amended by adding §§ 681a.1—681a.9 to read as set forth at 46 Pa.B. 1433.

(2) The Chairperson of the Board shall certify this order and 46 Pa.B. 1433 and deposit them with the Legislative Reference Bureau as required by law.

(3) This order shall take effect upon publication in the *Pennsylvania Bulletin*.

DAVID M. BARASCH,
Chairperson

(*Editor's Note*: See 46 Pa.B. 7051 (November 5, 2016) for IRRC's approval order.)

Fiscal Note: Fiscal Note 125-198 remains valid for the final adoption of the subject regulations.

[Pa.B. Doc. No. 16-1990. Filed for public inspection November 18, 2016, 9:00 a.m.]