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CHAPTER 28
RESTRUCTURING OF ELECTRIC UTILITY INDUSTRY

Sec.

Enactment. Chapter 28 was added December 3, 1996, P.L.802, No.138, effective January 1, 1997.

§ 2801. Short title of chapter.

This chapter shall be known and may be cited as the Electricity Generation Customer Choice and Competition Act.

§ 2802. Declaration of policy.

The General Assembly finds and declares as follows:

(1) Over the past 20 years, the Federal Government and State government have introduced competition in several industries that previously had been regulated as natural monopolies.

(2) Many state governments are implementing or studying policies that would create a competitive market for the generation of electricity.

(3) Because of advances in electric generation technology and Federal initiatives to encourage greater competition in the wholesale electric market, it is now in the public interest to permit retail customers to obtain direct access to a competitive generation market as long as safe and affordable transmission and distribution service is available at levels of reliability that are currently enjoyed by the citizens and businesses of this Commonwealth.

(4) Rates for electricity in this Commonwealth are on average higher than the national average, and significant differences exist among the rates of Pennsylvania electric utilities.

(5) Competitive market forces are more effective than economic regulation in controlling the cost of generating electricity.

(6) The cost of electricity is an important factor in decisions made by businesses concerning locating, expanding and retaining facilities in this Commonwealth.

(7) This Commonwealth must begin the transition from regulation to greater competition in the electricity generation market to benefit all classes of customers and to protect this Commonwealth's ability to compete in the national and international marketplace for industry and jobs.

(8) In moving toward greater competition in the electricity generation market, the Commonwealth must resolve certain transitional issues in a manner that is fair to customers, electric utilities, investors, the employees of electric utilities, local communities, nonutility generators of electricity and other affected parties.

(9) Electric service is essential to the health and well-being of residents, to public safety and to orderly economic development, and electric service should be available to all customers on reasonable terms and conditions.

(10) The Commonwealth must, at a minimum, continue the protections, policies and services that now assist customers who are low-income to afford electric service.

(11) In order to ensure the safety and reliability of the electric system, ensure the continued provision of high-quality customer service and avoid economic dislocation, utilities shall consider the experience and expertise of their work force in moving towards competition.

(12) The purpose of this chapter is to modify existing legislation and regulations and to establish standards and procedures in order to create direct access by retail

customers to the competitive market for the generation of electricity while maintaining the safety and reliability of the electric system for all parties. Reliable electric service is of the utmost importance to the health, safety and welfare of the citizens of the Commonwealth. Electric industry restructuring should ensure the reliability of the interconnected electric system by maintaining the efficiency of the transmission and distribution system.

(13) Under current law and regulation there exists some competition in the wholesale market for the generation of electricity, but the generation, transmission, distribution and retail sale of electricity is provided generally by public utilities under bundled rates regulated by the commission. The procedures established under this chapter provide for a fair and orderly transition from the current regulated structure to a structure under which retail customers will have direct access to a competitive market for the generation and sale or purchase of electricity.

(14) This chapter requires 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.

(15) In establishing the standards for the transition to and creation of a competitive electric market, heretofore, public utilities generally have had an obligation to serve customers within their defined service territories; consistent with that obligation, have undertaken long-term investments in generation, transmission and distribution facilities in order to meet the needs of their customers; and have entered into long-term power supply agreements as required by Federal law. In many instances, these investments and agreements have created costs which may not be recoverable in a competitive market. The commission is empowered under this chapter to determine the level of transition or stranded costs for each electric utility and to provide a mechanism, the competitive transition charge, for recovery of an appropriate amount of such costs in accordance with the standards established in this chapter.

(16) It is in the public interest for the transmission and distribution of electricity to continue to be regulated as a natural monopoly subject to the jurisdiction and active supervision of the commission. Electric distribution companies should continue to be the provider of last resort in order to ensure the availability of universal electric service in this Commonwealth unless another provider of last resort is approved by the commission.

(17) There are certain public purpose costs, including programs for low-income assistance, energy conservation and others, which have been implemented and supported by public utilities' bundled rates. The public purpose is to be promoted by continuing universal service and energy conservation

policies, protections and services, and full recovery of such costs is to be permitted through a nonbypassable rate mechanism.

(18) There are certain changes to a utility which will create transition costs to accomplish the move to a competitive market. These changes may entail the closure of facilities or reduction in employee levels. If such actions are to be undertaken, the utility must fully inform the commission of the impact of such decisions on local communities and on social services and of any tax implications of the actions. The utility is expected to discuss the transition to competition with its employees or their certified representatives and may provide severance, retraining, early retirement and outplacement services. Such transition costs may be recoverable under the competitive transition charge in section 2808 (relating to competitive transition charge).

(19) All participants in the restructured electric industry are encouraged to coordinate their plans and transactions through an independent system operator or its functional equivalent.

(20) Since continuing and ensuring the reliability of electric service depends on adequate generation and on conscientious inspection and maintenance of transmission and distribution systems, the independent system operator or its functional equivalent should set, and the commission shall set through regulations, inspection, maintenance, repair and replacement standards and enforce those standards.

(21) Under Federal and State clean air laws and regulations, electricity generators located in states to the west and south of this Commonwealth are not subject to requirements as stringent as those which apply to generators and other "persons" as defined in section 3 of the act of January 8, 1960 (1959 P.L.2119, No.787), known as the Air Pollution Control Act, operating in this Commonwealth and that different regions within this Commonwealth are subject to varying air emission requirements. Under some scenarios, competition among electricity generators located in different states and different regions within this Commonwealth could make it more difficult for areas in this Commonwealth to demonstrate attainment with Federal and State air quality standards. Since this result may be caused by the disparate requirements imposed by Federal and State law on generators and other "persons" as defined in section 3 of the Air Pollution Control Act in this Commonwealth and generators located in other states, the General Assembly supports changes to Federal clean air laws and regulations that will protect Pennsylvania's environment and ensure that electricity generators and other "persons" as defined in section 3 of the Air Pollution Control Act located in this Commonwealth are not placed at an undue competitive disadvantage. The commission will consult with the Department of Environmental Protection regarding this issue during the transition to retail competition.

Cross References. Section 2802 is referred to in section 2806 of this title.

§ 2803. Definitions.

The following words and phrases when used in this chapter shall have the meanings given to them in this section unless the context clearly indicates otherwise:

"Aggregator" or **"market aggregator."** An entity, licensed by the commission, that purchases electric energy and takes title to electric energy as an intermediary for sale to retail customers.

"Bilateral contract." An agreement, as approved by the commission, reached by two parties, each acting in its own independent self-interest, as a result of negotiations free of undue influence, duress or favoritism, in which the electric energy supplier agrees to sell and the electric distribution company agrees to buy a quantity of electric energy at a specified price for a specified period of time under terms agreed to by both parties, and which follows a standard industry template widely accepted in the industry or variations thereto accepted by the parties. Standard industry templates may include the EEI Master Agreement for physical energy purchases and sales and the ISDA Master Agreement for financial energy purchases and sales.

"Broker" or **"marketer."** An entity, licensed by the commission, that acts as an agent or intermediary in the sale and purchase of electric energy but that does not take title to electric energy.

"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 as determined by the commission under sections 2804 (relating to standards for restructuring of electric industry) and 2808 (relating to competitive transition charge).

"Consumer." A retail electric customer.

"Customer." A retail electric customer.

"Default service provider." An electric distribution company within its certified service territory or an alternative supplier approved by the commission that provides generation service to retail electric customers who:

(1) contract for electric power, including energy and capacity, and the chosen electric generation supplier does not supply the service; or

(2) do not choose an alternative electric generation supplier.

"Direct access." The right of electric generation suppliers and end-use customers to utilize and interconnect with the electric transmission and distribution system on a nondiscriminatory basis at rates, terms and conditions of service comparable to the transmission and distribution companies' own use of the system to transport electricity from any generator of electricity to any end-use customer.

"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 such building or facility and that supply electric power and other related electric power services to occupants of the building or facility.

"Electric generation supplier" or **"electricity supplier."** A person or corporation, including municipal corporations which choose to provide service outside their municipal limits except to the extent provided prior to the effective date of this chapter, brokers and marketers, aggregators or any other entities, that sells to end-use customers electricity or related services utilizing the jurisdictional transmission or distribution facilities of an electric distribution company 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 electric distribution company. The term 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. The term excludes electric cooperative corporations except as provided in 15 Pa.C.S. Ch. 74 (relating to generation choice for customers of electric cooperatives).

"End-use customer." A retail electric customer.

"Reliability." Includes adequacy and security. As used in this definition, "adequacy" means the provision of sufficient generation, transmission and distribution capacity so as to supply the aggregate electric power and energy requirements of consumers, taking into account scheduled and unscheduled outages of system facilities; and "security" means designing, maintaining and operating a system so that it can handle emergencies safely while continuing to operate.

"Renewable resource." Includes technologies such as solar photovoltaic energy, solar thermal energy, wind power, low-head hydropower, geothermal energy, landfill and mine-based methane gas, energy from waste and sustainable biomass energy.

"Retail customer." A retail electric customer.

"Retail electric customer." A direct purchaser of electric power. The term excludes an occupant of a building or facility where the owners/operators manage the internal distribution system serving such building or facility and supply electric power and other related power services to occupants of the building or facility; where such owners/operators are direct purchasers of electric power; and where the occupants are not direct purchasers.

"Transition or 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. This term includes:

(1) Regulatory assets and other deferred charges typically recoverable under current regulatory practice, the unfunded portion of the utility's projected nuclear generating plant decommissioning costs and cost obligations under contracts with nonutility generating projects which have received a commission order, the recoverability of which shall be determined under section 2808(c)(1) (relating to competitive transition charge).

(2) Prudently incurred costs related to cancellation, buyout, buydown or renegotiation of nonutility generating projects consistent with section 527 (relating to cogeneration rules and regulations), the recoverability of which shall be determined pursuant to section 2808(c)(2).

(3) The following costs, the recoverability of which shall be determined pursuant to section 2808(c)(3):

(i) Net plant investments and costs attributable to the utility's existing generation plants and facilities.

(ii) The utility's disposal of spent nuclear fuel.

(iii) The utility's long-term purchase power commitments other than the costs defined in paragraphs (1) and (2).

(iv) Retirement costs attributable to the utility's existing generating plants other than the costs defined in paragraph (1).

(v) Other transition costs of the utility, including costs of employee severance, retraining, early retirement, outplacement and related expenses, at reasonable levels, for employees who are affected by changes that occur as a result of the restructuring of the electric industry occasioned by this chapter.

The term includes any costs attributable to physical plants no longer used and useful because of the transition to retail competition. The term excludes any amounts previously disallowed by the commission as imprudently incurred. To the extent that the recoverability of amounts that are sought to be included as transition or stranded costs are subject to appellate review as of the time of the commission determination, any determination to include such costs shall be reversed to the extent required by the results of that appellate review.

"Transmission and distribution costs." All costs directly or indirectly incurred to provide transmission and distribution services to retail electric customers. This includes the return of and return on facilities and other capital investments necessary to provide transmission and distribution services and associated operating expenses, including applicable taxes.

"Universal service and energy conservation." Policies, protections and services that help low-income customers to maintain electric service. The term includes customer assistance programs, termination of service protection and policies and services that help low-income customers to reduce or manage energy consumption in a cost-effective manner, such as the low-income usage reduction programs, application of renewable resources and consumer education.

(Oct. 15, 2008, P.L.1592, No.129, eff. 30 days)

2008 Amendment. Act 129 added the defs. of "bilateral contract" and "default service provider." See the preamble to Act 129 of 2008 in the appendix to this title for special provisions relating to legislative findings and declarations.

References in Text. Chapter 74 of Title 15, referred to in the def. of "electric generation supplier" or "electricity supplier," is expired.

Cross References. Section 2803 is referred to in section 1403 of this title.

§ 2804. Standards for restructuring of electric industry.

The following interdependent standards shall govern the commission's assessment and approval of each public utility's restructuring plan, oversight of the transition process and regulation of the restructured electric utility industry:

(1) The commission shall ensure continuation of safe and reliable electric service to all consumers in the Commonwealth, including:

(i) The maintenance of adequate reserve margins by electric suppliers in conformity with the standards required by the North American Electric Reliability Council (NERC) and the regional reliability council appropriate to each supplier, or any successors to those reliability entities, and in conformity with established industry standards and practices.

(ii) The installation and maintenance of transmission and distribution facilities in conformity with established industry standards and practices, including the standards set forth in the National Electric Safety Code.

(2) Consistent with the time line set forth in section 2806 (relating to implementation, pilot programs and performance-based rates), the commission shall allow customers to choose among electric generation suppliers in a competitive generation market through direct access. Customers should be able to choose among alternatives such as firm and interruptible service, flexible pricing and alternate generation sources, including reasonable and fair opportunities to self-generate and interconnect. These alternatives may be provided by different electric generation suppliers.

(3) The commission shall require the unbundling of electric utility services, tariffs and customer bills to separate the charges for generation, transmission and distribution. The commission may require the unbundling of other services.

(4) The following caps on electric utility rates shall apply:

(i) For a period of 54 months from the effective date of this chapter or until an electric distribution utility is no longer recovering its transition or stranded costs through a competitive transition charge or intangible transition charge and all the customers of an electric distribution utility can choose an alternative provider of electric generation, whichever is shorter:

(A) the total charges of an electric distribution utility for service to any customer who purchases generation from that utility shall not exceed the total charges that have been approved by the commission for such service as of the effective date of this chapter; and

(B) for customers who purchase generation from a supplier other than the electric distribution utility, the charges of the utility for non-generation services that are regulated as of the effective date of this chapter, exclusive of the competitive transition charge and intangible transition charge, shall not exceed the non-generation charges that have been approved by the commission for such service as of the effective date of this chapter.

(ii) In addition to the rate cap set forth in subparagraph (i), for a period of nine years from the effective date of this chapter or until an electric distribution utility is no longer recovering its transition or stranded costs through a competitive transition charge or intangible transition charge and all customers of an electric distribution utility can choose an alternative provider of electric generation, whichever is shorter, the generation component of a utility's charges to customers who purchase generation from the utility, including the competitive transition charge and intangible transition charge, shall not exceed the generation component charged to the customers that has been approved by the commission for such service as of the effective date of this chapter.

(iii) An electric distribution utility may seek, and the commission may approve, an exception to the limitations set forth in subparagraphs (i) and (ii) only in any of the following circumstances:

(A) The electric distribution utility meets the requirements for extraordinary rate relief under section 1308(e) (relating to voluntary changes in rates).

(B) Either the electric distribution utility is required to begin payment under contracts with nonutility generation projects that have received commission orders, has been unable to mitigate such costs, such costs are not recoverable in a competitive generation market and such costs were not previously covered in the competitive transition charge or intangible transition charge, or the utility prudently incurs costs related to cancellation, buyout, buydown or renegotiation of nonutility generating project obligations of the utility consistent with section 527 (relating to cogeneration rules and regulations) and such costs were not previously covered in the competitive transition charge or intangible transition charge. Costs related to cancellation, buyout, buydown or renegotiation shall be recovered from ratepayers over a period not to exceed three years, unless the commission determines within its discretion to require a longer recovery period due to the magnitude of such costs, but shall be accounted for by the utility on a levelized basis over the total period in which the generation portion of the utility's rates are capped.

(C) The electric distribution utility is subject to significant increases in the rates of Federal or State taxes or other significant changes in law or regulations that would not allow the utility to earn a fair rate of return.

(D) The electric distribution utility is subject to significant increases in the unit rate of fuel for utility generation or the price of purchased power that are outside of the control of the utility and that would not allow the utility to earn a fair rate of return.

(E) The electric distribution utility is directed by the commission or an independent system operator or its functional equivalent to make expenditures to repair or upgrade its transmission or distribution system.

(F) The electric distribution utility seeks to increase its allowance for nuclear decommissioning costs to reflect new information not available at the time the utility's existing rates were determined, and such costs are not recoverable in the competitive generation market and are not covered in the competitive transition charge or intangible transition charge, and such costs would not allow the utility to earn a fair rate of return.

(G) As permitted by paragraph (16).

(iv) Consistent with the requirements of due process, the commission may expedite proceedings that invoke the provisions of subparagraph (iii).

(v) If an electric distribution utility rolls its energy cost rate into base rates at a combined level that does not exceed its combined level of such rates which have been approved by the commission as of the effective date of this chapter, the utility shall not be required to reduce its capped rates below the capped level upon the complaint of any party if the commission determines that any excess earnings achieved under the cap are being utilized to mitigate transition or stranded costs for the benefit of ratepayers or to offset other known and measurable cost increases that would be recoverable under traditional ratemaking but are not included within the capped rates.

(vi) This paragraph shall not apply to new services offered for the first time after the effective date of this chapter.

(5) The commission may permit, but shall not require, an electric utility to divest itself of facilities or to reorganize its corporate structure.

(6) Consistent with the provision of section 2806, the commission shall require that a public utility that owns or operates jurisdictional transmission and distribution facilities shall provide transmission and distribution service to all retail electric customers in their service territory and to electric cooperative corporations and electric generation suppliers, affiliated or nonaffiliated, on rates, terms of access and conditions that are comparable to the utility's own use of its system.

(7) The commission shall require that restructuring of the electric utility industry be implemented in a manner that does not unreasonably discriminate against one customer class to the benefit of another.

(8) The commission shall establish for each electric utility an appropriate cost-recovery mechanism which is designed to fully recover the electric utility's universal service and energy conservation costs over the life of these programs.

(9) The commission shall ensure that universal service and energy conservation policies, activities and services are appropriately funded and available in each electric distribution territory. Policies, activities and services under this paragraph shall be funded in each electric distribution territory by nonbypassable, competitively neutral cost-recovery mechanisms that fully recover the costs of universal service and energy conservation services. The

commission shall encourage the use of community-based organizations that have the necessary technical and administrative experience to be the direct providers of services or programs which reduce energy consumption or otherwise assist low-income customers to afford electric service. Programs under this paragraph shall be subject to the administrative oversight of the commission which will ensure that the programs are operated in a cost-effective manner.

(10) The commission shall establish rates for jurisdictional transmission and distribution services and shall continue to regulate distribution services for new and existing customers in accordance with this chapter and Chapter 13 (relating to rates and rate making).

(11) The time line for the transition to and phase-in of direct access to competitive electric generation shall be in accordance with section 2806.

(12) The commission has the authority to order utility participation in retail access pilot programs as set forth in section 2806 and as further implemented or modified by the commission, with direct access to begin on April 1, 1997. The commission shall conduct milestone reviews of the transition to retail electric generation competition to assure a technically workable and equitable transition period.

(13) Consistent with section 2808 (relating to competitive transition charge), the commission has the power and duty to approve a competitive transition charge for the recovery of transition or stranded costs it determines to be just and reasonable to recover from ratepayers.

(14) The transition to a competitive generation market shall be orderly, protect electric system reliability, be fair to ratepayers and provide the investors in Pennsylvania electric utilities with a fair opportunity to fully recover the amount of transition or stranded costs that the commission determines to be just and reasonable.

(15) At the time each utility files its restructuring plan with the commission, the utility shall submit an initial plan that sets forth how it shall meet its universal service and energy conservation obligations.

(16) The following shall apply:

(i) The commission shall issue regulations that permit the electric distribution company to recover any change in its State tax liability under sections 2806(h), 2809(c) (relating to requirements for electric generation suppliers) and 2810 (relating to revenue-neutral reconciliation) or in its liability under 52 Pa. Code §§ 69.51 through 69.56 (relating to inclusion of State taxes and gross receipts taxes in base rates) to the extent that the resulting rate does not exceed the rate cap established in this section except as provided in this chapter.

(ii) With regard to any portion of the change in an electric distribution company's tax liability under section 2810 which would cause it to exceed the rate cap, the electric distribution company may file a single issue rate proceeding under section 1308(a) to recover that amount. The commission shall adjudicate, within 60 days, whether the resulting rates are just and reasonable.

(iii) With regard to any portion of the change in an electric distribution company's tax liability under sections 2806(h) and 2809(c) which would cause it to exceed the price cap, upon certification to the commission by affidavit that the electric distribution company has not collected the taxes due pursuant to the tariff indemnification provisions required by section 2810(m) and that the electric distribution company and the Department of Revenue have not collected the taxes due pursuant to the other means set forth in sections 2806(g)(3)(i) and (ii) and 2809(c) to recover the taxes due and any interest thereon, the electric distribution utility shall be permitted to recover that amount in the State Tax Adjustment Surcharge.

Cross References. Section 2804 is referred to in sections 2803, 2806, 2807, 2812 of this title.

§ 2805. Regionalism and reciprocity.

(a) Other states.--The commission shall take all necessary and appropriate steps to encourage interstate power pools to enhance competition and to complement industry restructuring on a regional basis. The Commonwealth, the commission and Pennsylvania electric utilities shall work with the Federal Government, other states in the region and interstate power pools to accomplish the goals of restructuring and to establish independent system operators or their functional equivalents to operate the transmission system and interstate power pools. The commission, Pennsylvania electric utilities and all electricity suppliers shall work with the Federal Government, other states in the region, the North American Electric Reliability Council and its regional coordinating councils or their successors, interstate power pools, and with the independent system operator or its functional equivalent to ensure the continued provision of adequate, safe and reliable electric service to the citizens and businesses of this Commonwealth.

(b) Electric cooperatives, municipalities and other electric generation suppliers.--

(1) In order to make the benefits of competition in the generation and sale of electricity as widely available as possible to retail customers and to provide open, fair and nondiscriminatory access to all electric generation suppliers:

(i) Consistent with 15 Pa.C.S. Ch. 74 (relating to generation choice for customers of electric cooperatives), no electric cooperative or municipality which distributes electricity to end-use customers may utilize the transmission or distribution system of an electric utility regulated by the commission for the purpose of supplying electricity to an end-use customer unless the electric cooperative or municipality provides open and nondiscriminatory access and allows other electric generation suppliers to utilize its facilities, including any facilities it is entitled to provide to third parties pursuant to contract, to make sales to the end-use customers it serves. A borough may prohibit electric generation suppliers from serving end-use customers within its borough limits; however, such a borough shall be prohibited from providing generation service to end-use customers outside of its borough limits which it did not serve prior to the effective date of this chapter.

(ii) The commission shall require any electric cooperative seeking a certificate under 15 Pa.C.S. Ch. 74 to provide open and nondiscriminatory access to its transmission and distribution facilities as a condition to the granting of the certificate.

(iii) The reliability of the transmission service provided to electric cooperative corporations must be comparable to the reliability which the transmission supplier provides at the wholesale level.

(2) No electric utility regulated by the commission and no affiliate of such electric utility may use the distribution system of another electric utility regulated by the commission or make sales to end-use customers in another electric utility's service territory unless the commission has approved a restructuring plan for the supplying electric utility which provides for direct access comparable to the direct access provided under the approved plan of the electric utility operating the distribution system in the location where the supplying electric utility seeks to sell electricity to an end-use customer. No electric utility regulated by the commission and no affiliate of such electric utility may use the distribution system of an electric cooperative corporation or make sales to end-use customers in the territory of an electric cooperative corporation unless the commission has approved a restructuring plan for the supplying electric utility.

References in Text. Chapter 74 of Title 15, referred to in subsec. (b), is expired.

§ 2806. Implementation, pilot programs and performance-based rates.

(a) General rule.--The generation of electricity shall no longer be regulated as a public utility service or function except as otherwise provided for in this chapter at the conclusion of a transition and phase-in period beginning on the effective date of this chapter and ending, consistent with the commission's discretion under this section, January 1, 2001. As of January 1, 2001, consistent with the commission's discretion under this section, all customers of electric distribution companies in this Commonwealth shall have the opportunity to purchase electricity from their choice of electric generation suppliers. The ultimate choice of the electric generation supplier is to rest with the consumer.

(b) Schedule.--Recognizing that approximately 5% of the peak load will have retail access through pilot programs, the following schedule for phased implementation of retail access shall be adhered to unless a determination is made by the commission under subsection (c):

(1) As of January 1, 1999, a maximum of 33% of the peak load of each customer class shall have the opportunity for direct access.

(2) As of January 1, 2000, a maximum of 66% of the peak load of each customer class shall have the opportunity for direct access.

(3) As of January 1, 2001, all customers of electric distribution companies in this Commonwealth shall have the opportunity for direct access.

(4) The commission shall establish regulations specifying that, within each customer class, the customers that are eligible for direct access prior to full direct access shall be determined on a first-come-first-served basis unless otherwise determined by the commission through regulation, in the context of restructuring plans, or in other appropriate administrative proceedings, to prevent competitive disadvantages among similarly situated customers within a customer class.

(c) Additional time.--

(1) The commission may determine that an additional six-month transition period is necessary prior to the January 1, 1999, implementation date. A determination under this subsection must be made at least 45 days in advance of the scheduled date for implementation and must be based on one or more of the following considerations:

(i) Implementation would materially affect the reliability of the electric system.

(ii) Federal approvals necessary for the implementation of the provisions of this chapter have not been granted.

(iii) Communications and information systems necessary for the implementation of retail access have not been installed for reasons beyond the utility's control, as measured by appropriate industry standards.

(iv) Pennsylvania generators would be disadvantaged due to lack of regional reciprocity with respect to direct access.

(v) The interests of Pennsylvania consumers and the competitive position of Pennsylvania business and industry would be materially affected.

(vi) Such other consideration as would materially affect the orderly implementation of the legislative purpose of this chapter under section 2802(12) through (21) (relating to declaration of policy).

(2) Consistent with the considerations listed in paragraph (1), the commission may determine that an additional six-month transition period is necessary. This determination must be made by the commission by May 15, 1999.

(d) Filing of restructuring plans.--All electric utilities in this Commonwealth shall submit to the commission, pursuant to a schedule to be determined by the commission in consultation with the electric utilities, beginning on April 1, 1997, but in no event later than September 30, 1997, a restructuring plan to implement direct access to a competitive market for the generation of electricity.

(e) Contents of restructuring plans.--A restructuring plan under subsection (d) must include, consistent with the determinations of the commission, unbundled prices or rates for generation, jurisdictional transmission, distribution and other services; a proposed competitive transition charge; a proposed universal service and energy conservation cost-recovery mechanism; procedures for ensuring direct access to all licensed electric generation suppliers; a discussion of the impacts of the proposed plan on the utility's employees; and revised tariffs and rate schedules implementing the above.

(f) Commission review.--The commission shall review the restructuring plan filed by each electric utility and shall, after open evidentiary hearings with proper notice and opportunity for all parties to cross-examine witnesses, issue an order accepting, modifying or rejecting such plan at the earliest date possible, but no later than nine months from the filing of such restructuring plan. If the commission rejects a restructuring plan, it shall state the specific reasons for rejection and direct the electric utility to file an alternative plan addressing these objections within 30 days of the entry date of the commission order rejecting the plan. The commission shall review the alternative plan, solicit comments from interested parties and issue a final order within 45 days of the filing of the revised plan.

(g) Retail access pilot programs.--As of the effective date of this chapter, the commission has authority to order electric utilities to submit proposals for retail access pilot programs to begin April 1, 1997. The commission shall provide guidelines for retail access pilot programs by order.

(1) In order to determine whether all customers classes can benefit from competitive markets, utilities shall tailor proposed retail access pilot programs to accommodate the specific geographic, demographic and socioeconomic characteristics of their customer base. Retail access pilot programs must include an equal opportunity for the broadest practical direct access by all customer classes to electric generation suppliers.

(2) The minimum period of time for a retail access pilot program shall be one year and shall include an evaluation process as directed by the commission.

(3) In order to ensure the safety and reliability of the generation of electricity in this Commonwealth, participation in the retail access pilot programs shall be limited to electricity suppliers subject to commission licensure or certification.

(i) Each participating electricity supplier shall do all of the following:

(A) Certify to the commission that it will pay and in subsequent years has paid the full amount of taxes imposed by Articles II and XI of the act of March 4, 1971 (P.L.6, No.2), known as the Tax Reform Code of 1971, and any tax imposed by this chapter.

(B) Provide the commission with the address of the participant's principal office in this Commonwealth or the address of the participant's registered agent in this Commonwealth, the latter being the address at which the participant may be served process.

(C) Agree that it shall be subject to all taxes imposed by the Tax Reform Code of 1971 and any tax imposed by this chapter.

(ii) Failure of an electricity supplier to pay a tax referred to in subparagraph (i) or to otherwise comply with the provisions of this paragraph shall be cause for the commission to revoke the license of the electricity supplier.

(iii) If an electricity supplier, other than an electric distribution company, does not pay the tax imposed upon gross receipts under section 1101 of the Tax Reform Code of 1971 or this chapter, the electric distribution company to whose retail customer the electricity supplier provided generation service shall remit the unpaid tax, as a tax on the use of electricity in this Commonwealth, to the Department of Revenue and may collect or seek reimbursement of the tax so paid from the electricity provider or any other appropriate party that used the electricity in this Commonwealth. The department shall collect and enforce the use tax herein provided under section 1102 of the Tax Reform Code of 1971. Failure of the electric distribution company to pay the amount within 30 days after notice provided by the department shall cause interest to be imposed on the electric distribution company in accordance with Article XI of the Tax Reform Code of 1971. Interest shall be calculated from the 31st day after the department gives the notice required in this subparagraph. An electric distribution company or other appropriate person may challenge the imposition of the tax and interest by filing a petition with the department not later than 30 days after the date on which the tax became due.

(4) The percentage of utility load committed to a retail access pilot program must be approximately 5% of utility's peak load for each customer class. Waivers of this condition may be considered by the commission for economic development purposes or special circumstances.

(h) Flexible pricing.--In addition to the implicit authority of the commission under section 501 (relating to general powers), the commission has the authority to approve flexible pricing and flexible rates, including negotiated, contract-based tariffs designed to meet the specific needs of a utility customer and to address competitive alternatives.

(i) Performance-based rates and alternative regulation.--The commission has authority to use performance-based rates as an alternative to existing rate base/rate of return ratemaking, subject to the restrictions pertaining to rate caps in section 2804(4) (relating to standards for restructuring of electric industry).

Cross References. Section 2806 is referred to in sections 2804, 2807, 2810, 2812 of this title.

§ 2806.1. Energy efficiency and conservation program.

(a) Program.--The commission shall, by January 15, 2009, adopt an energy efficiency and conservation program to require electric distribution companies to adopt and implement cost-effective energy efficiency and conservation plans to reduce energy demand and consumption within the service territory of each electric distribution company in this Commonwealth. The program shall include:

(1) Procedures for the approval of plans submitted under subsection (b).

(2) An evaluation process, including a process to monitor and verify data collection, quality assurance and results of each plan and the program.

(3) An analysis of the cost and benefit of each plan submitted under subsection (b) in accordance with a total resource cost test approved by the commission.

(4) An analysis of how the program and individual plans will enable each electric distribution company to achieve or exceed the requirements for reduction in consumption under subsections (c) and (d).

(5) Standards to ensure that each plan includes a variety of energy efficiency and conservation measures and will provide the measures equitably to all classes of customers.

(6) Procedures to make recommendations as to additional measures that will enable an electric distribution company to improve its plan and exceed the required reductions in consumption under subsections (c) and (d).

(7) Procedures to require that electric distribution companies competitively bid all contracts with conservation service providers.

(8) Procedures to review all proposed contracts prior to the execution of the contract with conservation service providers to implement the plan. The commission may order the modification of a proposed contract to ensure that the plan meets the requirements for reduction in demand and consumption under subsections (c) and (d).

(9) Procedures to ensure compliance with requirements for reduction in consumption under subsections (c) and (d).

(10) A requirement for the participation of conservation service providers in the implementation of all or part of a plan.

(11) Cost recovery to ensure that measures approved are financed by the same customer class that will receive the direct energy and conservation benefits.

(b) Duties of electric distribution companies.--

(1) (i) By July 1, 2009, each electric distribution company shall develop and file an energy efficiency and conservation plan with the commission for approval to meet the requirements of subsection (a) and the requirements for reduction in consumption under subsections (c) and (d). The plan shall be implemented upon approval by the commission. The following are the plan requirements:

(A) The plan shall include specific proposals to implement energy efficiency and conservation measures to achieve or exceed the required reductions in consumption under subsections (c) and (d).

(B) A minimum of 10% of the required reductions in consumption under subsections (c) and (d) shall be obtained from units of Federal, State and local government, including municipalities, school districts, institutions of higher education and nonprofit entities.

(C) The plan shall explain how quality assurance and performance will be measured, verified and evaluated.

(D) The plan shall state the manner in which the plan will achieve the requirements of the program under subsection (a) and will achieve or exceed the required reductions in consumption under subsections (c) and (d).

(E) The plan shall include a contract with one or more conservation service providers selected by competitive bid to implement the plan or a portion of the plan as approved by the commission.

(F) The plan shall include estimates of the cost of implementation of the energy efficiency and conservation measures in the plan.

(G) The plan shall include specific energy efficiency measures for households at or below 150% of the Federal poverty income guidelines. The number of measures shall be proportionate to those households' share of the total energy usage in the service territory. The electric distribution company shall coordinate measures under this clause with other programs administered by the commission or another Federal or State agency. The expenditures of an electric distribution company under this clause shall be in addition to expenditures made under 52 Pa. Code Ch. 58 (relating to residential low income usage reduction programs).

(H) The plan shall include a proposed cost-recovery tariff mechanism, in accordance with section 1307 (relating to sliding scale of rates; adjustments), to fund the energy efficiency and conservation measures and to ensure full and current recovery of the prudent and reasonable costs of the plan, including administrative costs, as approved by the commission.

(I) The electric distribution company shall demonstrate that the plan is cost effective using a total resource cost test approved by the commission and provides a diverse cross section of alternatives for customers of all rate classes.

(J) The plan shall require an annual independent evaluation of its cost-effectiveness and a full review of the results of each five-year plan required under subsection (c)(3) and, to the extent practical, how the plan will be adjusted on a going-forward basis as a result of the evaluation.

(K) The plan shall include an analysis of the electric distribution company's administrative costs.

(ii) A new plan shall be filed with the commission every five years or as otherwise required by the commission. The plan shall set forth the manner in which the company will meet the required reductions in consumption under subsections (c) and (d).

(iii) No more than 2% of funds available to implement a plan under this subsection shall be allocated for experimental equipment or devices.

(2) The commission shall direct an electric distribution company to modify or terminate any part of a plan approved under this section if, after an adequate period for implementation, the commission determines that an energy efficiency or conservation measure included in the plan will not achieve the required reductions in consumption in a cost-effective manner under subsections (c) and (d).

(3) If part of a plan is modified or terminated under paragraph (2), the electric distribution company shall submit

a revised plan describing actions to be taken to offer substitute measures or to increase the availability of existing measures in the plan to achieve the required reductions in consumption under subsections (c) and (d).

(c) Reductions in consumption.--The plans adopted under subsection (b) shall reduce electric consumption as follows:

(1) By May 31, 2011, total annual weather-normalized consumption of the retail customers of each electric distribution company shall be reduced by a minimum of 1%. The 1% load reduction in consumption shall be measured against the electric distribution company's expected load as forecasted by the commission for June 1, 2009, through May 31, 2010, with provisions made for weather adjustments and extraordinary loads that the electric distribution company must serve.

(2) By May 31, 2013, the total annual weather-normalized consumption of the retail customers of each electric distribution company shall be reduced by a minimum of 3%. The 3% load reduction in consumption shall be measured against the electric distribution company's expected load as forecasted by the commission for June 1, 2009, through May 31, 2010, with provisions made for weather adjustments and extraordinary loads that the electric distribution company must serve.

(3) By November 30, 2013, and every five years thereafter, the commission shall evaluate the costs and benefits of the program established under subsection (a) and of approved energy efficiency and conservation plans submitted to the program. The evaluation shall be consistent with a total resource cost test or a cost-benefit analysis determined by the commission. If the commission determines that the benefits of the program exceed the costs, the commission shall adopt additional required incremental reductions in consumption.

(d) Peak demand.--The plans adopted under subsection (b) shall reduce electric demand as follows:

(1) By May 31, 2013, the weather-normalized demand of the retail customers of each electric distribution company shall be reduced by a minimum of 4.5% of annual system peak demand in the 100 hours of highest demand. The reduction shall be measured against the electric distribution company's peak demand for June 1, 2007, through May 31, 2008.

(2) By November 30, 2013, the commission shall compare the total costs of energy efficiency and conservation plans implemented under this section to the total savings in energy and capacity costs to retail customers in this Commonwealth or other costs determined by the commission. If the commission determines that the benefits of the plans exceed the costs, the commission shall set additional incremental requirements for reduction in peak demand for the 100 hours of greatest demand or an alternative reduction approved by the commission. Reductions in demand shall be measured from the electric distribution company's peak demand for the period from June 1, 2011, through May 31, 2012. The reductions in consumption required by the commission shall be accomplished no later than May 31, 2017.

(e) Commission approval.--

(1) The commission shall conduct a public hearing on each plan and allow for the submission of recommendations by the Office of Consumer Advocate and the Office of Small Business Advocate and by members of the public as to how the electric

distribution company could improve its plan or exceed the required reductions in consumption under subsections (c) and (d).

(2) The commission shall approve or disapprove a plan filed under subsection (b) within 120 days of submission. The following shall apply to an order disapproving a plan:

(i) The commission shall describe in detail the reasons for the disapproval.

(ii) The electric distribution company shall have 60 days to file a revised plan to address the deficiencies identified by the commission. The revised plan shall be approved or disapproved by the commission within 60 days.

(f) Penalties.--

(1) The following shall apply for failure to submit a plan:

(i) An electric distribution company that fails to file a plan under subsection (b) shall be subject to a civil penalty of $100,000 per day until the plan is filed.

(ii) An electric distribution company that fails to file a revised plan under subsection (e)(2)(ii) shall be subject to a civil penalty of $100,000 per day until the plan is filed.

(iii) Penalties collected under this paragraph shall be deposited in the low-income electric customer assistance program of the energy distribution company for the respective service territory.

(2) The following shall apply to an electric distribution company that fails to achieve the reductions in consumption required under subsection (c) or (d):

(i) The electric distribution company shall be subject to a civil penalty not less than $1,000,000 and not to exceed $20,000,000 for failure to achieve the required reductions in consumption under subsection (c) or (d). Any penalty paid by an electric distribution company under this subparagraph shall not be recoverable from ratepayers.

(ii) If an electric distribution company fails to achieve the required reductions in consumption under subsection (c) or (d), responsibility to achieve the reductions in consumption shall be transferred to the commission. The commission shall do all of the following:

(A) Implement a plan to achieve the required reductions in consumption under subsection (c) or (d).

(B) Contract with conservation service providers as necessary to implement any portion of the plan.

(g) Limitation on costs.--The total cost of any plan required under this section shall not exceed 2% of the electric distribution company's total annual revenue as of December 31, 2006. The provisions of this paragraph shall not apply to the cost of low-income usage reduction programs established under 52 Pa. Code Ch. 58 (relating to residential low income usage reduction programs).

(h) Costs.--The commission shall recover from electric distribution companies the costs of implementing the program established under this section.

(i) Report.--The following shall apply:

(1) Technologies, management practices or other measures employed by retail customers that reduce electricity consumption or demand if all of the following apply:

(i) The technology, practice or other measure is installed on or after the effective date of this section at the location of a retail customer.

(ii) The technology, practice or other measure reduces consumption of energy or peak load by the retail customer.

(iii) The cost of the acquisition or installation of the measure is directly incurred in whole or in part by the electric distribution company.

(2) Energy efficiency and conservation measures shall include solar or solar photovoltaic panels, energy efficient windows and doors, energy efficient lighting, including exit sign retrofit, high bay fluorescent retrofit and pedestrian and traffic signal conversion, geothermal heating, insulation, air sealing, reflective roof coatings, energy efficient heating and cooling equipment or systems and energy efficient appliances and other technologies, practices or measures approved by the commission.

"Peak demand." The highest electrical requirement occurring during a specified period. For an electric distribution company, the term shall mean the sum of the metered consumption for all retail customers over that period.

"Quality assurance." All of the following:

(1) The auditing of buildings, equipment and processes to determine the cost-effectiveness of energy efficiency and conservation measures using nationally recognized tools and certification programs.

(2) Independent inspection of completed energy efficiency and conservation measures completed by third-party entities to evaluate the quality of the completed measure.

"Real-time price." A rate that directly reflects the different cost of energy during each hour.

"Time-of-use rate." A rate that reflects the costs of serving customers during different time periods, including off-peak and on-peak periods, but not as frequently as each hour.

"Total resource cost test." A standard test that is met if, over the effective life of each plan not to exceed 15 years, the net present value of the avoided monetary cost of supplying electricity is greater than the net present value of the monetary cost of energy efficiency conservation measures.

(Oct. 15, 2008, P.L.1592, No.129, eff. 30 days)

2008 Amendment. Act 129 added section 2806.1. See the preamble to Act 129 of 2008 in the appendix to this title for special provisions relating to legislative findings and declarations.

§ 2806.2. Energy efficiency and conservation.

(a) Registry.--The commission shall, by March 1, 2009, establish a registry of approved persons qualified to provide conservation services to all classes of customers. In order to be included in the registry, a conservation service provider must meet experience and other qualifications determined by the commission.

(b) Application.--The commission shall develop an application for registration under subsection (a) and may charge a reasonable registration fee.
(Oct. 15, 2008, P.L.1592, No.129, eff. 30 days)

2008 Amendment. Act 129 added section 2806.2. See the preamble to Act 129 of 2008 in the appendix to this title for special provisions relating to legislative findings and declarations.

§ 2807. Duties of electric distribution companies.

(a) General rule.--Each electric distribution company shall maintain the integrity of the distribution system at least in conformity with the National Electric Safety Code and such other standards practiced by the industry in a manner sufficient to provide safe and reliable service to all customers connected to the system consistent with this title and the commission's regulations. In performing such duties, the electric distribution company shall implement procedures to require all electric generation suppliers to deliver energy to the electric distribution company at locations and in amounts which are adequate to meet the energy supplier's obligations to its customers. Subject to commission approval, the electric distribution company may require that the customer install, at the customer's expense, enhanced metering capability sufficient to match the energy delivered by the electric generation suppliers with consumption by the customer.

(b) Procedures for review by the commission.--There shall be a rebuttable presumption that the electric distribution company has the ability to receive energy at all points on its system sufficient to meet the needs of all electric generation suppliers' customers on its system. The electric distribution company shall not have an obligation to install nonstandard facilities, either as to type or location, for the purpose of receiving energy from the energy supplier unless the energy supplier or its customer pays the full cost of these facilities. Nothing in this chapter shall prevent the electric distribution company from upgrading its system to meet changing customer requirements consistent with the requirements of section 1501 (relating to character of service and facilities), and the commission may establish incentive programs to encourage such system upgrades. Disputes concerning facilities shall be subject to the jurisdiction of the commission and may be initiated by the filing of a complaint under section 701 (relating to complaints) by the electric generation supplier or the customer.

(c) Customer billing.--Subject to the right of an end-use customer to choose to receive separate bills from its electric generation supplier, the electric distribution company may be responsible for billing customers for all electric services, consistent with the regulations of the commission, regardless of the identity of the provider of those services.

(1) Customer bills shall contain unbundled charges sufficient to enable the customer to determine the basis for those charges.

(2) If services are provided by an entity other than the electric distribution company, the entity that provides those services shall furnish to the electric distribution company billing data sufficient to enable the electric distribution company to bill customers.

(3) The electric distribution company shall not be required to forward payment to entities providing services to customers, and on whose behalf the electric distribution company is billing those customers, before the electric distribution company has received payment for those services from customers.

(d) Consumer protections and customer service.--The electric distribution company shall continue to provide customer service functions consistent with the regulations of the commission, including meter reading, complaint resolution and collections. Customer services shall, at a minimum, be maintained at the same level of quality under retail competition.

(1) The commission shall establish regulations to ensure that an electric distribution company does not change a customer's electricity supplier without direct oral confirmation from the customer of record or written evidence of the customer's consent to a change of supplier.

(2) The commission shall establish regulations to require each electric distribution company, electricity supplier, marketer, aggregator and broker to provide adequate and accurate customer information to enable customers to make informed choices regarding the purchase of all electricity services offered by that provider. Information shall be provided to consumers in an understandable format that enables consumers to compare prices and services on a uniform basis.

(3) Prior to the implementation of any restructuring plan under section 2806 (relating to implementation, pilot programs and performance-based rates), each electric distribution company, in conjunction with the commission, shall implement a consumer education program informing customers of the changes in the electric utility industry. The program shall provide consumers with information necessary to help them make appropriate choices as to their electric service. The education program shall be subject to approval by the commission.

(e) Obligation to serve.--A default service provider's obligation to provide electric generation supply service following the expiration of a generation rate cap specified under section 2804(4) (relating to standards for restructuring of electric industry) or a restructuring plan under section 2806(f) is revised as follows:

(1) While an electric distribution company collects either a competitive transition charge or an intangible transition charge or until 100% of its customers have choice, whichever is longer, the electric distribution company shall continue to have the full obligation to serve, including the connection of customers, the delivery of electric energy and the production or acquisition of electric energy for customers.

(2) (Deleted by amendment).

(3) (Deleted by amendment).

(3.1) Following the expiration of an electric distribution company's obligation to provide electric generation supply service to retail customers at capped rates, if a customer contracts for electric generation supply service and the chosen electric generation supplier does not provide the service or if a customer does not choose an alternative electric generation supplier, the default service provider shall provide electric generation supply service to that customer pursuant to a commission-approved competitive procurement plan. The electric power acquired shall be procured through competitive procurement processes and shall include one or more of the following:

(i) Auctions.

(ii) Requests for proposal.

(iii) Bilateral agreements entered into at the sole discretion of the default service provider which shall be at prices which are:

(A) no greater than the cost of obtaining generation under comparable terms in the wholesale market, as determined by the commission at the time of execution of the contract; or

(B) consistent with a commission-approved competition procurement process. Any agreement between affiliated parties shall be subject to review and approval of the commission under Chapter 21 (relating to relations with affiliated interests). In no case shall the cost of obtaining generation from any affiliated interest be greater than the cost of obtaining generation under comparable terms in the wholesale market at the time of execution of the contract.

(3.2) The electric power procured pursuant to paragraph (3.1) shall include a prudent mix of the following:

(i) Spot market purchases.

(ii) Short-term contracts.

(iii) Long-term purchase contracts, entered into as a result of an auction, request for proposal or bilateral contract that is free of undue influence, duress or favoritism, of more than four and not more than 20 years. The default service provider shall have sole discretion to determine the source and fuel type. Long-term purchase contracts under this subparagraph may not constitute more than 25% of the default service provider's projected default service load unless the commission, after a hearing, determines for good cause that a greater portion of load is necessary to achieve least cost procurement. This subparagraph shall not apply to contracts executed under paragraph (5).

(3.3) The commission may determine that a contract is required to be extended for a longer term of up to 20 years, if the extension is necessary to ensure adequate and reliable service at least cost to customers over time.

(3.4) The prudent mix of contracts entered into pursuant to paragraphs (3.2) and (3.3) shall be designed to ensure:

(i) Adequate and reliable service.

(ii) The least cost to customers over time.

(iii) Compliance with the requirements of paragraph (3.1).

(3.5) Except as set forth in paragraph (5)(ii), the provisions of this section shall apply to any type of energy purchased by a default service provider to provide electric generation supply service, including energy or alternative energy portfolio standards credits required to be purchased under the act of November 30, 2004 (P.L.1672, No.213), known as the Alternative Energy Portfolio Standards Act. The commission shall apply paragraph (3.4) to comparable types of energy sources.

(3.6) The default service provider shall file a plan for competitive procurement with the commission and obtain commission approval of the plan considering the standards in paragraphs (3.1), (3.2), (3.3) and (3.4) before the competitive process is implemented. The commission shall hold hearings as necessary on the proposed plan. If the commission fails to issue a final order on the plan within nine months of the date that the plan is filed, the plan shall be deemed to be approved and the default service provider may implement the plan as filed. Costs incurred through an approved competitive procurement plan shall be deemed to be the least cost over time as required under paragraph (3.4)(ii).

(3.7) At the time the commission evaluates the plan and prior to approval, in determining if the default electric service provider's plan obtains generation supply at the least cost, the commission shall consider the default service provider's obligation to provide adequate and reliable service to customers and that the default service provider has obtained a prudent mix of contracts to obtain least cost on a long-term, short-term and spot market basis and shall make specific findings which shall include the following:

(i) The default service provider's plan includes prudent steps necessary to negotiate favorable generation supply contracts.

(ii) The default service provider's plan includes prudent steps necessary to obtain least cost generation supply contracts on a long-term, short-term and spot market basis.

(iii) Neither the default service provider nor its affiliated interest has withheld from the market any generation supply in a manner that violates Federal law.

(3.8) Notwithstanding sections 508 (relating to power of the commission to vary, reform and revise contracts) and 2102 (relating to approval of contracts with affiliated interests), the commission may modify contracts or disallow costs only when the party seeking recovery of the costs of a procurement plan is, after hearing, found to be at fault for the following:

(i) not complying with the commission-approved procurement plan; or

(ii) the commission of fraud, collusion or market manipulation with regard to these contracts.

(3.9) The default service provider shall have the right to recover on a full and current basis, pursuant to a reconcilable automatic adjustment clause under section 1307 (relating to sliding scale of rates; adjustments), all reasonable costs incurred under this section and a commission-approved competitive procurement plan.

(4) If a customer that chooses an alternative supplier and subsequently desires to return to the local distribution company for generation service, the local distribution company shall treat that customer exactly as it would any new applicant for energy service.

(5) (i) Notwithstanding paragraph (3.1), the electric distribution company or commission-approved alternative supplier may, in its sole discretion, offer large

customers with a peak demand of 15 megawatts or greater at one meter at a location in its service territory any negotiated rate for service at all of the customers' locations within the service territory for any duration agreed upon by the electric distribution company or commission-approved alternative supplier and the large customer. The commission shall permit, but shall not require, an electric distribution company or commission-approved alternative supplier to provide service to large customers under this paragraph. Contract rates entered into under this paragraph shall be subject to review by the commission in order to ensure that all costs related to the rates are borne by the parties to the contract and that no costs related to the rates are borne by other customers or customer classes. If no costs related to the rates are borne by other customers or customer classes, the commission shall approve the contract within 90 days of its filing, or it shall be deemed approved by operation of law upon expiration of the 90 days. Information submitted under this paragraph shall be subject to the commission's procedures for the filing of confidential and proprietary information.

(ii) For purposes of providing service under this paragraph to customers with a peak demand of 20 megawatts or greater at one meter at a location within that distribution company's service territory, an electric distribution company that has completed its restructuring transition period as of the effective date of this paragraph may, in its sole discretion, acquire an interest in a generation facility or construct a generation facility specifically to meet the energy requirements of the customers, including the electric requirements of the customers' other billing locations within its service territory. The electric distribution company must commence construction of the generation facility or contract to acquire the generation interest within three years after the effective date of this paragraph, except that the electric distribution company may add to the generation facilities it commenced construction or contracted to acquire after this three-year period to serve additional load of customers for whom it commenced construction or contracted to acquire generation within three years. Nothing in this paragraph requires or authorizes the commission to require an electric distribution company to commence construction or acquire an interest in a generation facility. The electric distribution company's interest in the generation facility it built or contracted to acquire shall be no larger than necessary to meet peak demand of customers served under this subparagraph. During times when the customer's demand is less than the electric distribution company's generation interest, the electric distribution company may sell excess power on the wholesale market. At no time shall the costs associated with the generating facility interests be included in rate base or otherwise reflected in rates. The generation facility interests shall not be commission-regulated assets.

(6) A default service plan approved by the commission prior to the effective date of this section shall remain in

effect through its approved term. At its sole discretion, the default service provider may propose amendments to its approved plan that are consistent with this section, and the commission shall issue a decision whether to approve or disapprove the proposed amendments within nine months of the date that the amendments are filed. If the commission fails to issue a final order within nine months, the amendments shall be deemed to be approved and the default service provider may implement the amendments as filed.

(7) The default service provider shall offer residential and small business customers a generation supply service rate that shall change no more frequently than on a quarterly basis. All default service rates shall be reviewed by the commission to ensure that the costs of providing service to each customer class are not subsidized by any other class.

(f) Smart meter technology and time of use rates.--

(1) Within nine months after the effective date of this paragraph, electric distribution companies shall file a smart meter technology procurement and installation plan with the commission for approval. The plan shall describe the smart meter technologies the electric distribution company proposes to install in accordance with paragraph (2).

(2) Electric distribution companies shall furnish smart meter technology as follows:

(i) Upon request from a customer that agrees to pay the cost of the smart meter at the time of the request.

(ii) In new building construction.

(iii) In accordance with a depreciation schedule not to exceed 15 years.

(3) Electric distribution companies shall, with customer consent, make available direct meter access and electronic access to customer meter data to third parties, including electric generation suppliers and providers of conservation and load management services.

(4) In no event shall lost or decreased revenues by an electric distribution company due to reduced electricity consumption or shifting energy demand be considered any of the following:

(i) A cost of smart meter technology recoverable under a reconcilable automatic adjustment clause under section 1307(b), except that decreased revenues and reduced energy consumption may be reflected in the revenue and sales data used to calculate rates in a distribution rate base rate proceeding filed under section 1308 (relating to voluntary changes in rates).

(ii) A recoverable cost.

(5) By January 1, 2010, or at the end of the applicable generation rate cap period, whichever is later, a default service provider shall submit to the commission one or more proposed time-of-use rates and real-time price plans. The commission shall approve or modify the time-of-use rates and real-time price plan within six months of submittal. The default service provider shall offer the time-of-use rates and real-time price plan to all customers that have been provided with smart meter technology under paragraph (2)(iii). Residential or commercial customers may elect to participate in time-of-use rates or real-time pricing. The default service provider shall submit an annual report to the price programs

and the efficacy of the programs in affecting energy demand and consumption and the effect on wholesale market prices.

(6) The provisions of this subsection shall not apply to an electric distribution company with 100,000 or fewer customers.

(7) An electric distribution company may recover reasonable and prudent costs of providing smart meter technology under paragraph (2)(ii) and (iii), as determined by the commission. This paragraph includes annual depreciation and capital costs over the life of the smart meter technology and the cost of any system upgrades that the electric distribution company may require to enable the use of the smart meter technology which are incurred after the effective date of this paragraph, less operating and capital cost savings realized by the electric distribution company from the installation and use of the smart meter technology. Smart meter technology shall be deemed to be a new service offered for the first time under section 2804(4)(vi). An electric distribution company may recover smart meter technology costs:

(i) through base rates, including a deferral for future base rate recovery of current basis with carrying charge as determined by the commission; or

(ii) on a full and current basis through a reconcilable automatic adjustment clause under section 1307.

(g) Definition.--As used in this section, the term "smart meter technology" means technology, including metering technology and network communications technology capable of bidirectional communication, that records electricity usage on at least an hourly basis, including related electric distribution system upgrades to enable the technology. The technology shall provide customers with direct access to and use of price and consumption information. The technology shall also:

(1) Directly provide customers with information on their hourly consumption.

(2) Enable time-of-use rates and real-time price programs.

(3) Effectively support the automatic control of the customer's electricity consumption by one or more of the following as selected by the customer:

(i) the customer;

(ii) the customer's utility; or

(iii) a third party engaged by the customer or the customer's utility.

(July 17, 2007, P.L.120, No.36, eff. imd.; Oct. 15, 2008, P.L.1592, No.129, eff. 30 days)

2008 Amendment. Act 129 amended subsec. (e) and added subsecs. (f) and (g).

§ 2808. Competitive transition charge.

(a) General rule.--To provide each electric utility with an opportunity to recover its transition or stranded costs following the commission's determination under subsection (c), every customer accessing the transmission or distribution network shall pay a competitive transition charge to the electric distribution company in whose certificated territory that customer is located. The costs to be recovered shall be allocated to customer classes in a manner that does not shift interclass or intraclass costs and maintains consistency with the allocation methodology for utility production plant accepted by the commission in the electric utility's most recent base rate proceeding. If a customer installs on-site generation which operates in parallel with other generation on the public utility's system and which significantly reduces the customer's purchases of electricity through the transmission and distribution network, the customer's fully allocated share of transition or stranded costs shall be recovered from the customer through a competitive transition charge. The recovery of transition or stranded costs associated with existing generating facilities is contingent on continued operation at reasonable availability levels of the generation facilities for which recovery has been approved, except when the generation facility is uneconomic on a production cost basis because of the transition to a competitive market.

(b) Period for collecting competitive transition charge.--The competitive transition charge shall be included on bills to customers for a period not to exceed nine years from the effective date of this chapter unless an alternative payment methodology is mutually agreed upon by the customer and the utility or unless the commission in its discretion and for good cause shown orders an alternative payment period. In establishing the length of the period for collection of the competitive transition charge, the commission shall consider the effect on the ability of the Commonwealth to compete in attracting industry and jobs, on the financial health of electric utilities and other relevant factors.

(c) Determination of competitive transition charge.--In determining the level of transition or stranded costs that an electric utility may recover through the competitive transition charge, the commission shall apply the following principles:

(1) The commission shall allow recovery of regulatory assets and other deferred charges typically recoverable under current regulatory practice, the unfunded portion of the utility's projected nuclear generating plant decommissioning costs and cost obligations under contracts with nonutility generating projects that have received a commission order. Nothing in this chapter shall be construed as requiring an electric utility or a nonutility generating project to enter into an arrangement to buy down, buy out and terminate or otherwise restructure a contract or as authorizing the commission to require a utility to pursue such an arrangement with a nonutility generating project.

(2) The commission shall allow recovery of an electric utility's prudently incurred costs related to cancellation, buyout, buydown or renegotiation of nonutility generating projects consistent with section 527 (relating to cogeneration rules and regulations).

(3) The commission shall determine the level of other generation-related transition or stranded costs that may be recovered through the competitive transition charge.

(4) The commission shall consider the extent to which the electric utility has undertaken efforts to mitigate generation-related transition or stranded costs by appropriate means in a manner that is reasonable under all of the circumstances, including consideration of whether mitigation has been commensurate with the magnitude of the electric utility's generation-related transition or stranded costs. During the transition period, electric utilities shall have

the duty to mitigate generation-related transition or stranded costs to the extent practicable. Efforts may include the following:

(i) Acceleration of depreciation and amortization of existing rate base generation assets.

(ii) Minimization of new capital spending for existing rate base generation assets.

(iii) Reallocation of depreciation reserves to existing rate base generation assets.

(iv) Reduction of book assets by application of new proceeds of any sale of idle or underutilized existing rate base generation assets.

(v) Maximization of market revenues from existing rate base generation assets.

(vi) Issuance of securitized debt pursuant to the provisions of section 2812 (relating to approval of transition bonds).

(5) Of equal importance to the mitigation efforts under paragraph (4), the commission shall consider efforts undertaken over time, prior to the enactment of this chapter, to reduce or moderate customer rate levels while maintaining safe and efficient operations.

(d) Commission review.--As a component of its restructuring plan, each electric utility shall file with the commission a recovery plan, including a proposed competitive transition charge and supporting documentation. In evaluating a recovery plan and any proposed competitive transition charge, the commission shall schedule open evidentiary hearings with proper notice and opportunity for all parties to cross-examine witnesses as necessary.

(e) Use of transition bonds.--After the effective date of this chapter, a utility may apply to the commission for a qualified rate order under section 2812 for some or all of its transition or stranded costs.

(1) In evaluating a utility application under this subsection, the commission shall schedule hearings, as necessary.

(2) If the commission issues a qualified rate order under section 2812 and if the transition bonds approved by that order are successfully issued, then:

(i) the utility shall impose and collect through its customer bills the intangible transition charges approved by that qualified rate order; and

(ii) simultaneously, either the utility's rates for electric service or the utility's competitive transition charges shall be reduced by an amount equal to the revenue requirement of the transition or stranded costs for which transition bonds have been successfully issued.

(f) Annual revenue.--Consistent with section 1307(e) (relating to sliding scale of rates; adjustments), the commission shall establish procedures for the annual review of the competitive transition charge. The review shall reconcile the annual revenues received from the charge with the annual amortization of transition or stranded costs approved by the commission under this section. The commission shall adjust the competitive transition charge based upon underrecovery or overrecovery of the annual amortization amount.

Cross References. Section 2808 is referred to in sections 2802, 2803, 2804, 2812 of this title.

§ 2809. Requirements for electric generation suppliers.

(a) License requirement.--No person or corporation, including municipal corporations which choose to provide service outside their municipal limits except to the extent provided prior to the effective date of this chapter, brokers and marketers, aggregators and other entities, shall engage in the business of an electric generation supplier in this Commonwealth unless the person or corporation holds a license issued by the commission. Consistent with 15 Pa.C.S. Ch. 74 (relating to generation choice for customers of electric cooperatives), electric cooperative corporations must possess a certificate for service to supply generation services beyond their territorial limits.

(b) License application and issuance.--An application for an electric generation supplier license must be made to the commission in writing, be verified by oath or affirmation and be in such form and contain such information as the commission may by its regulations require. A license shall be issued to any qualified applicant, authorizing the whole or any part of the service covered by the application, if it is found that the applicant is fit, willing and able to perform properly the service proposed and to conform to the provisions of this title and the lawful orders and regulations of the commission under this title, including the commission's regulations regarding standards and billing practices, and that the proposed service, to the extent authorized by the license, will be consistent with the public interest and the policy declared in this chapter; otherwise, such application shall be denied.

(c) Financial responsibility.--

(1) In order to ensure the safety and reliability of the generation of electricity in this Commonwealth, no energy supplier license shall be issued or remain in force unless the holder complies with all of the following:

(i) Furnishes a bond or other security approved by the commission in form and amount to ensure the financial responsibility of the electric generation supplier and the supply of electricity at retail in accordance with contracts, agreements or arrangements.

(ii) Certifies to the commission that it will pay and in subsequent years has paid the full amount of taxes imposed by Articles II and XI of the act of March 4, 1971 (P.L.6, No.2), known as the Tax Reform Code of 1971, and any tax imposed by this chapter.

(iii) Provides the commission with the address of the participant's principal office in this Commonwealth or the address of the participant's registered agent in this Commonwealth, the latter being the address at which the participant may be served process.

(iv) Agrees that it shall be subject to all taxes imposed by the Tax Reform Code of 1971 and any tax imposed by this chapter.

Failure of an electricity supplier to pay a tax referred to in this paragraph or to otherwise comply with the provisions of this paragraph shall be cause for the commission to revoke the license of the electricity supplier.

(2) If an electricity supplier other than an electric distribution company does not pay the tax imposed upon gross

receipts under section 1101 of the Tax Reform Code of 1971 or this chapter, the electric distribution company to whose retail customer the electricity supplier provided generation service shall remit the unpaid tax, as a tax on the use of electricity in this Commonwealth, to the Department of Revenue and may collect or seek reimbursement of the tax so paid from the electricity provider or any other appropriate party that used the electricity in this Commonwealth. The department shall collect and enforce the use tax herein provided under section 1102 of the Tax Reform Code of 1971. Failure of the electric distribution company to pay the amount within 30 days after notice provided by the department shall cause interest to be imposed on the electric distribution company in accordance with Article XI of the Tax Reform Code of 1971. Interest shall be calculated from the 31st day after the department gives the notice required in this paragraph. An electric distribution company or other appropriate person may challenge the imposition of the tax and interest by filing a petition with the department not later than 30 days after the date on which the tax became due.

(d) Transferability of licenses.--No license issued under this chapter may be transferred without prior commission approval.

(e) Form of regulation of electric generation suppliers.--The commission may forbear from applying requirements of this part which it determines are unnecessary due to competition among electric generation suppliers. In regulating the service of electric generation suppliers, the commission shall impose requirements necessary to ensure that the present quality of service provided by electric utilities does not deteriorate, including assuring that adequate reserve margins of electric supply are maintained and assuring that 52 Pa. Code Ch. 56 (relating to standards and billing practices for residential utility service) are maintained.

(f) Availability of the services of brokers and marketers or aggregators.--Prior to approving the licensure of any broker and marketer or aggregator, the commission shall set forth standards to ensure that all retail customer classes may choose to purchase electricity through a broker and marketer or aggregator. The commission shall also ensure that brokers, marketers and aggregators comply with 52 Pa. Code Ch. 56.

(g) Annual fees.--The commission may establish, by order or rule, on a reasonable cost basis, fees to be charged for annual activities related to the oversight of electric generation suppliers.

(Oct. 22, 2014, P.L.2545, No.155, eff. 60 days)

2014 Amendment. Act 155 added subsec. (g). See section 1 of Act 155 in the appendix to this title for special provisions relating to legislative findings and declarations.

References in Text. Chapter 74 of Title 15, referred to in subsec. (a), is expired.

Cross References. Section 2809 is referred to in sections 102, 2804, 2810 of this title.

§ 2810. Revenue-neutral reconciliation.

(a) General intent of revenue-neutral reconciliation.--It is the intention of the General Assembly that the restructuring of the electric industry be accomplished in a manner that allows Pennsylvania to enjoy the benefits of competition, promotes the competitiveness of Pennsylvania's electric utilities and maintains revenue neutrality to the Commonwealth. This section is not intended to cause a shift in proportional tax obligations among customer classes or individual electric distribution companies. It is the intention of the General Assembly to establish this revenue replacement at a level necessary to recoup losses that may result from the restructuring of the electric industry and the transition thereto.

(b) Imposition.--

(1) For tax periods beginning on or after January 1, 1999, a tax at the rate provided in subsection (c) is imposed upon the gross receipts of electric distribution companies and electric generation suppliers.

(2) A tax at the rate provided in subsection (c) is imposed upon the gross receipts of any municipality owned or operated public utility or of any public utility service furnished by any municipality. Gross receipts shall be exempt from the tax to the extent that gross receipts are derived from sales of electric energy inside the limits of the municipality owning or operating the public utility or furnishing the public utility service.

(3) A tax at the rate provided in subsection (c) is imposed upon the gross receipts derived from any electric cooperative owned or operated public utility or from any public utility service furnished by any electric cooperative. Gross receipts shall be exempt from the tax to the extent that gross receipts are derived from sales for resale or sales of electric energy within the limits of its service territory as set forth in 15 Pa.C.S. § 7406 (relating to competition by electric cooperatives).

(c) Rate.--

(1) By December 1, 1998, and each October 1 thereafter until and including October 1, 2002, the Secretary of Revenue shall publish the rate of tax as provided in paragraph (2) in the form of a notice in the Pennsylvania Bulletin and the rate shall apply to the tax imposed by subsection (b) for the period beginning the next January 1. The tax rate published on October 1, 2002, shall continue in force without further adjustment. If the commission determines under section 2806(c) (relating to implementation, pilot programs and performance-based rates) to extend the transition period by more than six months, the requirement for an annual adjustment of the tax rate shall be extended by one additional year. The secretary shall also certify the rate calculated to the majority and minority chairs of the Appropriations Committee of the Senate and the Appropriations Committee of the House of Representatives and detail the calculations of the rate.

(2) The secretary shall calculate the rate for the periods beginning on and after January 1, 1999, in the manner set forth in this paragraph:

(i) Multiply the 1995-1996 fiscal tax revenue base by a fraction, the numerator of which is the total kilowatt hours of electricity distributed for ultimate consumption in Pennsylvania in the preceding calendar year as certified by the commission and the denominator of which is the total kilowatt hours of electricity distributed for ultimate consumption in Pennsylvania in the calendar year 1995 as certified by the commission.

(ii) From the product derived under subparagraph (i), subtract the total cash payments made to the department during the Commonwealth's preceding fiscal year on account of affected taxes actually paid by each electric distribution company and electric generation supplier and by any other entity, including a successor, whose affected taxes are contained in the 1995-1996 fiscal tax revenue base.

(iii) Divide the difference derived under subparagraph (ii) by the total gross receipts in the preceding calendar year as certified by the commission to determine the tax rate. The tax rate under this subparagraph shall be a decimal rounded to three places.

(3) On August 1, 2000, August 1, 2001, and August 1, 2002, the department shall deliver a report to the General Assembly and the Governor that shall describe the dynamic economic effect upon the affected taxes due to electric utility restructuring. It is the purpose of this report to provide the General Assembly and the Governor with information to determine whether it is appropriate to consider modifying the calculation described in paragraph (2) to reflect additional tax revenues, if any, resulting from the dynamic economic effects upon the affected taxes.

(4) If the effective rate for any affected tax is different from the effective rate for such affected tax in the 1995-1996 fiscal tax revenue base, an adjustment shall be made to the computation of the rate of tax under paragraph (2) by multiplying that portion of the 1995-1996 fiscal tax revenue base attributable to the affected tax by a fraction, the numerator of which is the effective rate of the affected tax for the preceding fiscal year and the denominator of which is the effective rate of tax of the affected tax in the base fiscal year.

(5) For negative rates:

(i) If the rate of tax calculated for a tax year prior to the tax year beginning January 1, 2004, or January 1, 2005, in the event of an extension by more than six months by the commission as provided in section 2806(c) is negative, a credit equal to the negative tax rate for such tax year multiplied by the taxable gross receipts for that tax year shall be allowed against the taxpayer's liability for any tax for that tax year imposed under Article XI of the act of March 4, 1971 (P.L.6, No.2), known as the Tax Reform Code of 1971.

(ii) If the rate of tax calculated as the final adjustment is negative for the tax period beginning January 1, 2003, or January 1, 2004, in the event of an extension by more than six months by the commission as provided in section 2806(c), the rate of tax imposed by section 1101(b) of the Tax Reform Code of 1971 for the tax years beginning January 1, 2004, and thereafter, or January 1, 2005, and thereafter, in the event of an extension by more than six months, shall be adjusted and set as follows: the tax rate expressed as a decimal rounded to three positions shall be subtracted from .044 or the current rate imposed under section 1101(b) of the Tax Reform Code of 1971 to determine the adjusted tax rate. The adjusted tax rate shall be published in the Pennsylvania Bulletin.

(6) Information to be provided to the department or the commission shall be as follows:

(i) To ensure the identification of cash payments for purposes of subsection (d), the commission shall require any licensee, electric distribution company, electric generation supplier or other person affected to disclose on its license application, renewal or transfer its State tax account or similar number relative to any of the taxes specified.

(ii) The commission shall report and certify to the secretary of the department by August 1, 1998, and each August 1 thereafter the total amount of electricity distributed for ultimate consumption in this Commonwealth during the previous two calendar years and the total gross receipts for the past year.

(iii) As a condition of licensure, the commission shall require each electric distribution company and electric generation supplier to report their annual gross receipts in this Commonwealth.

(iv) For purposes of enforcing sections 2806 and 2809 (relating to requirements for electric generation suppliers) as they relate to the payment of State taxes, an applicant for the grant, renewal or transfer of a license issued under this title shall, by filing an application with the commission, waive confidentiality with respect to State tax information regarding the applicant in the possession of the department, regardless of the source of the information, and shall consent to the department providing that information to the commission.

(7) (Repealed).

(d) Payment of tax and reports.--The tax imposed under subsection (b) shall be paid within the time prescribed by law. For the purpose of ascertaining the amount of the tax, the treasurer or other appropriate officer of the taxpayer shall transmit to the department by March 15 an annual report, and under oath or affirmation, of the amount of gross receipts received by the taxpayer during the prior calendar year. The treasurer or other appropriate officer of the taxpayer liable to report or pay taxes imposed under subsection (b), except municipalities and cooperatives, shall transmit to the department by March 15 a tentative report for the prior calendar year. The tentative report shall set forth all of the following:

(i) The amount of gross receipts received in the period of 12 months next preceding and reported in the annual report.

(ii) The gross receipts received in the first three months of the current calendar year.

(iii) Other information as the department may require.

(e) Tax computation.--Upon the date its tentative report is required to be made, the taxpayer making a tentative report shall transmit the report to the department on account of the tax due for the current calendar year and compute and make payment of the tentative tax with the report under section 3003 of the Tax Reform Code of 1971.

(f) Time to file reports.--The time for filing annual reports may be extended, estimated settlements may be made by the department if reports are not filed, and the penalties for failing to file reports and pay the taxes imposed under subsection (b) shall be as prescribed by the laws defining the powers and duties of the department. If the works of a taxpayer are operated by another taxpayer, the taxes imposed under subsection (b) shall be apportioned between the taxpayers in accordance with the terms of their respective leases or agreements. For the payment of the apportioned taxes, the Commonwealth shall first look to the taxpayer operating the works. Upon payment by that taxpayer, no other taxpayer shall be held liable for any tax imposed under subsection (b).

(g) Timely mailing treated as timely filing and payment.--Notwithstanding the provisions of any State tax law to the contrary, whenever payment of all or any portion of a State tax is required by law to be received by the department or other agency of the Commonwealth by a day certain, the taxpayer shall be deemed to have complied with that law if the letter transmitting payment of the tax which has been received by the department is postmarked by the United States Postal Service on or prior to the final day on which the payment is to be received.

(h) Procedure, enforcement and penalties.--Parts III, IV, VI and VII of Article IV and Article XXX of the Tax Reform Code of 1971 shall apply to this section insofar as they are consistent with this section and applicable to the tax imposed under subsection (b). Notwithstanding the provisions of section 403(d) of the Tax Reform Code of 1971, if the officers of any corporation subject to tax under this chapter neglect or refuse to make a report as required in this chapter or knowingly make a false report, the department shall add to the tax determined to be due a penalty of 5% of the amount of tax due for each month or fraction of a month until the penalty has reached 25% and thereafter a penalty of 1% of the amount of tax due for each month or fraction of a month. Penalties added to the tax shall not bear interest.

(i) Electric light, waterpower and hydroelectric utilities.--The terms "electric light company," "waterpower company" and "hydro-electric company," as used in section 1101(b) of the Tax Reform Code of 1971, shall be deemed to include electric distribution companies and electric generation suppliers.

(j) Sales of electric energy.--Retail sales of electric generation, transmission, distribution or supply of electric energy, dispatching services, customer services, competitive transition charges, intangible transition charges and universal service and energy conservation charges and such other retail sales in this Commonwealth the receipts of which, if bundled, would have been deemed to be sales of electric energy prior to the effective date of this chapter shall be deemed sales of electric energy for purposes of section 1101 of the Tax Reform Code of 1971. The phrases "doing business in this Commonwealth" and "engaged in electric light and power business, waterpower business and hydro-electric business in this Commonwealth," as such terms are used in section 1101(b) of the Tax Reform Code of 1971 and in this chapter, shall be construed to include the direct or indirect engaging in, transacting or conducting of activity in this Commonwealth for the purpose of establishing or maintaining a market for the sales of electric energy and include obtaining a license or certification from the commission to supply electric energy. Retail sales of generation shall be deemed to occur at the meter of the retail consumer.

(k) Electric cooperatives.--Section 1101(b) of the Tax Reform Code of 1971 shall apply to electric cooperatives and impose a tax upon the gross receipts derived from any electric cooperative owned or operated public utility or from any public utility service furnished by any electric cooperative. Gross receipts shall be exempt from the tax to the extent that the gross receipts are derived from sales for resale or sales of electric energy within the limits of its service territory as set forth in 15 Pa.C.S. § 7406.

(l) Provisions to be construed with utilities gross receipts tax.--Subsections (i), (j) and (k) shall be construed in conjunction with Article XI of the Tax Reform Code of 1971 and shall be effective for tax years beginning January 1, 1997, and thereafter.

(m) Indemnification.--The electric distribution utility company's tariff shall provide that, if an electric distribution company becomes liable under sections 2806(g) and 2809(c) for State taxes not paid by an electric generation supplier, that electric generation supplier shall indemnify the electric distribution company for the amount of the liability so imposed upon the electric distribution utility.

(n) Definitions.--As used in this section, the following words and phrases shall have the meanings given to them in this subsection:

"Affected taxes." The taxes imposed under Articles II, IV, VI and XI and section 2301(f) of the act of March 4, 1971 (P.L.6, No.2), known as the Tax Reform Code of 1971.

"Base fiscal year." The year beginning on July 1, 1995, and ending on June 30, 1996.

"Department." The Department of Revenue of the Commonwealth.

"Effective rate." The tax rate applicable during the fiscal year or, if more than one rate is applicable, the average of the rates that were in effect for each month of the fiscal year.

"Fiscal year." A year beginning on July 1 and ending on the subsequent June 30.

"Gross receipts." The gross receipts from the retail sales of electric energy as defined in section 1101(b) of the Tax Reform Code of 1971.

"1995-1996 fiscal tax revenue base." The receipts from affected taxes from the fiscal year 1995-1996, such amount being $984,141,837.

"Portion of the 1995-1996 fiscal tax revenue base attributable to the affected tax." The following amounts for the tax indicated:

Tax	Amount
Corporate net income tax	$181,628,433
Capital stock-franchise tax	$117,495,605
Sales and use tax	$187,401,632
Public utility realty tax	$ 43,883,573
Utilities gross receipts tax	$453,732,594

"Total utilities gross receipts." The total gross receipts for a calendar year for all electric distribution companies and electric generation suppliers which are derived from the sales of electric energy and required to be reported to the commission under subsection (c)(6)(iii).

(Dec. 23, 2003, P.L.250, No.46, eff. imd.)

2003 Repeal. Act 46 repealed subsec. (c)(7).

References in Text. Section 7406 of Title 15, referred to in subsec. (b)(3), expired.

Cross References. Section 2810 is referred to in sections 102, 2804 of this title.

§ 2811. Market power remediation.

(a) Monitoring competitive conditions.--The commission shall monitor the market for the supply and distribution of electricity to retail customers and take steps as set forth in this section to prevent anticompetitive or discriminatory conduct and the unlawful exercise of market power.

(b) Initiation of investigations.--Upon complaint or upon its own motion for good cause shown, the commission shall conduct an investigation of the impact on the proper functioning of a fully competitive retail electricity market, including the effect of mergers, consolidations, acquisition or disposition of assets or securities of electricity suppliers, transmission congestion and anticompetitive or discriminatory conduct affecting the retail distribution of electricity.

(c) Conduct of investigations.--

(1) The commission may require an electricity supplier to provide information, including documents and testimony, in accordance with the commission's regulations regarding the discovery of information from any electricity supplier.

(2) Confidential, proprietary or trade secret information provided under this subsection shall not be disclosed to any person not directly employed or retained by the commission to conduct the investigation without the consent of the party providing the information.

(3) Notwithstanding the prohibition on disclosure of information in paragraph (2), the commission shall disclose information obtained under this subsection to the Office of Consumer Advocate and the Office of Small Business Advocate under an appropriate confidentiality agreement. The commission may disclose the information to appropriate Federal or State law enforcement officials if it determines that the disclosure of the information is necessary to prevent or restrain a violation of Federal or State law and it provides the party that provided the information with reasonable notice and opportunity to prevent or limit disclosure.

(d) Referrals and intervention.--If, as a result of an investigation conducted under this section, the commission has reason to believe that anticompetitive or discriminatory conduct, including the unlawful exercise of market power, is preventing the retail electricity customers in this Commonwealth from obtaining the benefits of a properly functioning and workable competitive retail electricity market, the commission, pursuant to its regulations, shall:

(1) Refer its findings to the Attorney General, the United States Department of Justice, the Securities and Exchange Commission or the Federal Energy Regulatory Commission.

(2) Subject to subsection (c)(3), disclose any information it has obtained in the course of its investigation to the agency or agencies to which it has made a referral under paragraph (1).

(3) Intervene, as provided and permitted by law or regulation, in any proceedings initiated as a result of a referral made under paragraph (1).

(e) Approval of proposed mergers, consolidations, acquisitions or dispositions.--

(1) In the exercise of authority the commission otherwise may have to approve the mergers or consolidations by electric utilities or electricity suppliers, or the acquisition or disposition of assets or securities of other public utilities or electricity suppliers, the commission shall consider whether the proposed merger, consolidation, acquisition or disposition is likely to result in anticompetitive or discriminatory conduct, including the unlawful exercise of market power, which will prevent retail electricity customers in this Commonwealth from obtaining the benefits of a properly functioning and workable competitive retail electricity market.

(2) Upon request for approval, the commission shall provide notice and an opportunity for open, public evidentiary hearings. If the commission finds, after hearing, that a proposed merger, consolidation, acquisition or disposition is likely to result in anticompetitive or discriminatory conduct, including the unlawful exercise of market power, which will prevent retail electricity customers in this Commonwealth from obtaining the benefits of a properly functioning and workable competitive retail electricity market, the commission shall not approve such proposed merger, consolidation, acquisition or disposition, except upon such terms and conditions as it finds necessary to preserve the benefits of a properly functioning and workable competitive retail electricity market.

(e.1) Market misconduct.--

(1) If an electric distribution company or any of its affiliated companies or any company that an electric distribution company has purchased generation from is found guilty of market manipulation, exercising market power or collusion by the Federal Energy Regulatory Commission or any Federal or State court or, if an electric distribution company or any one of its affiliated companies or any company that an electric distribution company has purchased generation from settles a claim of market manipulation, exercising market power or collusion that is brought by a regional transmission operator's market monitoring unit, the Federal Energy Regulatory Commission or another entity, the commission:

(i) Shall direct the electric distribution company to take any and all reasonable action to quantify the effect of the market misconduct upon Pennsylvania ratepayers.

(ii) Following public hearing on the matter and a finding of public interest, may direct the electric distribution company to take any and all reasonable legal action, including the filing of a lawsuit as may be necessary, to recover the quantified damages which shall be used to recompense Pennsylvania ratepayers affected by the market misconduct.

(2) If the electric distribution company fails to pursue reasonable action to quantify or seek recovery of damages for Pennsylvania ratepayers affected by market manipulation, the exercise of market power or collusion, the commission is

authorized, following notice and an opportunity of the electric distribution company to comply or contest, to assess a civil penalty, which shall not be recovered in rates, of not more than $10,000 per day for failure or neglect to obey an order of the commission, the continuance of the failure or neglect being a separate offense.

(3) Any monetary damages recovered by the electric distribution company shall be paid to affected Pennsylvania ratepayers in the form of a credit to their electric bills or as refunds.

(4) The provisions of this subsection shall be held to be in addition to and not in substitution for or limitation of any other provision of this title.

(f) Preservation of rights.--Nothing in this section shall restrict the right of any party to pursue any other remedy available to it under this part.
(Oct. 15, 2008, P.L.1592, No.129, eff. 30 days)

2008 Amendment. Act 129 added subsec. (e.1).

§ 2812. Approval of transition bonds.

(a) Qualified rate orders.--Notwithstanding any other provision of law, the commission is authorized to issue qualified rate orders in accordance with the provisions of this subsection to facilitate the recovery or financing of qualified transition expenses of an electric utility or assignee.

(1) A qualified rate order may be adopted by the commission only upon the application of an electric utility and shall become effective in accordance with its terms. After the issuance of a qualified rate order, the electric utility retains sole discretion regarding whether to assign, sell or otherwise transfer intangible transition property or to cause the transition bonds to be issued, including the right to defer or postpone such assignment, sale, transfer or issuance.

(2) After the effective date of this chapter, an electric utility may file an application for a qualified rate order pursuant to the following procedures:

(i) Each application for a qualified rate order shall contain a complete accounting of the utility's transition or stranded costs, detailed information regarding the utility's proposal for the sale of intangible transition property or the issuance of transition bonds and information regarding the electric utility's planned use of the proceeds of the sale or issuance. After the utility has filed its restructuring plan under section 2806 (relating to implementation, pilot programs and performance-based rates), the utility may incorporate by reference the information in the restructuring plan in providing the information.

(ii) An electric utility may file an application for a qualified rate order concurrently with, prior to, during or following the filing of its restructuring plan under section 2806. If an electric utility requests expedited review under subsection (b)(1)(i) or (ii), it shall designate in its application the portion of its total claimed transition or stranded costs for which it requests such expedited review.

(iii) After notice and an opportunity to be heard, the commission may issue a final qualified rate order for all or a portion of the amount of transition or stranded costs that it finds would be just and reasonable for the utility to recover from ratepayers under sections 2804 (relating to standards for restructuring of electric industry) and 2808 (relating to competitive transition charge). The commission shall issue a final qualified rate order only for the amounts for which it finds such issuance to be in the public interest. The commission shall complete its review of the application and issue its final determination by the later of nine months from the filing, unless the electric utility requests expedited treatment under subsection (b), or 15 days following the filing of the electric utility's restructuring plan under section 2806.

(b) Expedited review procedures.--

(1) The commission shall provide for expedited review of applications for qualified rate orders upon request of the electric utility pursuant to the following procedures:

(i) If the utility elects to file an application prior to the filing of its restructuring plan and requests expedited review, the commission, after notice and an opportunity to be heard, may issue a final qualified rate order approving the issuance of transition bonds for a portion of the utility's transition or stranded costs that the commission finds would be just and reasonable to recover from ratepayers under sections 2804 and 2808. The commission shall consider only the portion of the transition or stranded costs for which the utility requests approval to issue transition bonds. Consideration of all remaining amounts and amounts not resolved by the commission shall be deferred for consideration in the electric utility's restructuring plan proceeding under section 2806. The commission shall complete its review of the application and issue its final determination within 120 days after the request for expedited review but in no event earlier than 15 days after the utility has filed its restructuring plan under section 2806.

(ii) If the electric utility files an application for a qualified rate order concurrently with its restructuring plan or during the course of the restructuring plan proceeding, the electric utility may request, and the commission may allow, an accelerated determination of the application. After notice and an opportunity to be heard, the commission may issue a final qualified rate order approving the issuance of transition bonds for a portion of the utility's stranded or transition costs that the commission finds would be just and reasonable to recover from ratepayers under sections 2804 and 2808. The commission shall consider only the portion of the utility's transition or stranded costs for which the utility seeks expedited review. Consideration of all remaining amounts and amounts not resolved by the commission shall be deferred for consideration in a final order regarding the utility's restructuring plan under section 2806. The commission shall complete its review of the application and issue its final determination within 120 days after the request for expedited review.

(iii) If the electric utility files an application for a qualified rate order after the commission enters a final order regarding the utility's restructuring plan, and requests expedited treatment, the commission shall complete its review and issue its final determination within 120 days of the request for expedited review.

(2) The qualified rate order shall require that the proceeds from the assignment, sale or transfer or other financing of intangible transition property shall be used principally to reduce the electric utility's transition or stranded costs and to reduce the related capitalization, pursuant to a plan submitted by the electric utility in its application for a qualified rate order and approved by the commission.

(3) Notwithstanding any other provision of law, the commission has the power to specify that all or a portion of a qualified rate order shall be irrevocable. To the extent so specified, neither the order nor the intangible transition charges authorized to be imposed and collected under the order shall be subject to reduction, postponement, impairment or termination by any subsequent action of the commission. Nothing in this paragraph is intended to supersede the right of any party to judicial review of the qualified rate order.

(4) The commission shall provide in any qualified rate order for a procedure for the expeditious approval by the commission of periodic adjustments to the intangible transition charges that are the subject of the pertinent qualified rate order. Such adjustments shall ensure the recovery of revenues sufficient to provide for the payment of principal, interest, acquisition or redemption premium and for other fees, costs and charges in respect of transition bonds approved by the commission as part of or in conjunction with a qualified rate order. The commission shall determine whether the adjustments are required on each anniversary of the issuance of the qualified rate order and at the additional intervals as may be provided for in the qualified rate order. The adjustments, if required, shall be approved within 90 days of each anniversary of the issuance of the qualified rate order or of each additional interval provided for in the qualified rate order.

(5) Notwithstanding any other provision of law, on such conditions as the commission may approve, all or portions of the interest of an electric utility in intangible transition property may be assigned, sold or transferred to an assignee and may be pledged or assigned as security by an electric utility or assignee to or for the benefit of a financing party. To the extent that an interest is assigned, sold or transferred or is pledged or assigned as security, the commission shall authorize the electric utility to contract with the assignee or financing party that the electric utility will continue to operate its system to provide service to its customers, will impose and collect the applicable intangible transition charges for the benefit and account of the assignee or financing party and will account for and remit the applicable intangible transition charge to or for the account of the assignee or financing party. If the qualified rate order so provides, the obligations of the electric utility:

(i) shall be binding upon the electric utility, its successors and assigns; and

(ii) shall be required by the commission to be undertaken and performed by the electric utility and any other entity which provides electric service to a person that was a customer of an electric utility located within the certificated territory of the electric utility on the effective date of this chapter or that became a customer of electric services within such territory after the effective date of this chapter and is still located within such territory, as a condition to the provision of service to such customer by such electric utility or other entity, unless the customer has paid a termination charge in the manner and on the basis specified in the qualified rate order.

(6) The irrevocable status of any portion of a qualified rate order under paragraph (3) shall lapse and terminate to the extent that an assignment, sale or transfer of the intangible transition property resulting from the rate order or the issuance of the related transition bonds is not effected within the period specified in the qualified rate order.

(7) The effect of any subsequent refinancing of transition bonds upon the rates authorized in a qualified rate order shall be as provided in such order.

(8) In its qualified rate order, the commission shall afford flexibility in establishing the terms and conditions of the transition bonds, including repayment schedules, interest rates and other financing costs. The electric utility shall file the final terms of issuance with the commission.

(c) Intangible transition property.--

(1) Any right that an electric utility has in the intangible transition property prior to its sale or transfer or any other right created under this section or created in the qualified rate order and assignable under this section or assignable pursuant to a qualified rate order shall be only a contract right.

(2) The Commonwealth pledges to and agrees with the holders of any transition bonds issued under this section and with any assignee or financing party who may enter into contracts with an electric utility under this section that the Commonwealth will not limit or alter or in any way impair or reduce the value of intangible transition property or intangible transition charges approved by a qualified rate order until the transition bonds and interest on the transition bonds are fully paid and discharged or the contracts are fully performed on the part of the electric utility. Subject to other requirements of law, nothing in this paragraph shall preclude limitation or alteration if adequate compensation is made by law for the full protection of the intangible transition charges collected pursuant to a qualified rate order and of the holder of this transition bond and any assignee or financing party entering into contract with the electric utility.

(d) Security interests in intangible transition property.--

(1) Neither intangible transition property nor any right, title or interest of a utility or assignee described in paragraph (1) of the definition of "intangible transition

property" in subsection (g), whether before or after the issuance of the qualified rate order, shall constitute "an account" or "general intangibles" under 13 Pa.C.S. § 9102 (relating to definitions and index of definitions) nor shall any such right, title or interest pertaining to a qualified rate order, including the associated intangible transition property and any revenues, collections, claims, payments, money or proceeds of or arising from intangible transition charges pursuant to such order, be deemed proceeds of any right or interest other than in the order and the intangible transition property arising from the order.

(2) The granting, perfection and enforcement of security interests in intangible transition property to secure transition bonds is governed by this section rather than by Title 13 (relating to commercial code).

(3) A valid and enforceable security interest in intangible transition property shall attach and be perfected only by means of a separate filing with the commission, under regulations the commission prescribes. For this purpose:

(i) If the transition bonds are issued to finance any qualified transition expenses, as specified in the applicable qualified rate order, the lien of the bonds shall attach automatically to the intangible transition property relating to the expenses from the time of issuance of the bonds.

(ii) The lien under subparagraph (i) shall be deemed a valid and enforceable security interest in the intangible transition property securing the qualified transition bonds and shall be continuously perfected if, before the date of issuance specified in subparagraph (i) or within no more than ten days after the date, a filing has been made by or on behalf of the financing party to protect that security interest in accordance with the procedures prescribed by the commission under this subsection. Any filing in respect to such transition bonds shall take precedence over any other filing.

(iii) The lien under subparagraph (i) is enforceable against the assignee and all third parties, including judicial lien creditors, subject only to the rights of any third parties holding security interests in the intangible transition property previously perfected in the manner described in this subsection if value has been given by the purchasers of transition bonds. A perfected lien in intangible transition property is a continuously perfected security interest in all revenues and proceeds arising with respect to the associated intangible transition property, whether or not revenues have accrued. Intangible transition property constitutes property for the purposes of contracts securing transition bonds, whether or not the related revenues have accrued. The lien created under this paragraph is perfected and ranks prior to any other lien, including any judicial lien, which subsequently attaches to the intangible transition property, to the intangible transition charges and to the qualified rate order and any rights created by the order or any proceeds of the order. The relative priority of a lien created under this paragraph is not defeated or adversely affected by changes to the qualified rate order or to the intangible transition charges payable by any customer.

(iv) The relative priority of a lien created under this paragraph is not defeated or adversely affected by the commingling of revenues arising with respect to intangible transition property with funds of the electric utility or other funds of the assignee.

(v) If an event of default occurs under approved transition bonds, the holders of transition bonds or their authorized representatives, as secured parties, may foreclose or otherwise enforce the lien in the intangible transition property securing the transition bonds, subject to the rights of any third parties holding prior security interests in the intangible transition property perfected in the manner provided in this subsection. Upon application by the holders or their representatives, without limiting their other remedies, the commission shall order the sequestration and payment to the holders or their representatives of revenues arising with respect to the intangible transition property pledged to the holders. An order under this subparagraph shall remain in full force and effect notwithstanding any bankruptcy, reorganization or other insolvency proceedings with respect to the electric utility or assignee.

(4) The commission shall establish and maintain a separate system of records to reflect the date and time of receipt of all filings made under this subsection and may provide that transfers of intangible transition property to an assignee be filed in accordance with the same system.

(e) True sale.--A transfer of intangible transition property by an electric utility to an assignee which the parties have in the governing documentation expressly stated to be a sale or other absolute transfer, in a transaction approved in a qualified rate order, shall be treated as an absolute transfer of all of the transferor's right, title and interest, as in a true sale, and not as a pledge or other financing, of the intangible transition property, other than for Federal and State income and franchise tax purposes. Granting to holders of transition bonds a preferred right to the intangible transition property or the provision by the electric utility of any credit enhancement with respect to transition bonds shall not impair or negate the characterization of any transfer as a true sale, other than for Federal and State income and franchise tax purposes. A transfer of intangible transition property shall be deemed perfected as against third persons, including any judicial lien creditors, when all of the following have taken place:

(1) The commission has issued the qualified rate order creating intangible transition property.

(2) A sale or transfer of the intangible transition property in writing has been executed and delivered to the assignee.

(f) Actions with respect to intangible transition charges.--

(1) Nothing in this chapter shall entitle any person to bring an action against a retail electric customer for nonpayment of intangible transition charges, other than the electric utility, its successor or any other entity which provides electric service to a person that was a customer of an electric utility located within the certificated territory

of the electric utility on the effective date of this chapter or that became a customer of electric services within such territory after the effective date of this chapter and is still located within such territory.

(2) The commission has exclusive jurisdiction over any dispute arising out of the obligations to impose and collect intangible transition charges of an electric utility, its successor or any other entity which provides electric service to a person that was a customer of an electric utility located within the certificated territory of the electric utility on the effective date of this chapter or that became a customer of electric services within such territory after the effective date of this chapter and is still located within such territory.

(g) Definitions.--As used in this section, the following words and phrases shall have the meanings given to them in this subsection:

"Assignee." An entity, including a corporation, public authority, trust or financing vehicle, to which an electric utility assigns, sells or transfers other than as security all or a portion of its interest in or right to intangible transition property. The term includes an entity, including a corporation, public authority, trust or financing vehicle to which a direct assignee of an electric utility may assign, sell or transfer other than as security its interest in or right to intangible transition property.

"Financing party." A holder of transition bonds, including trustees, collateral agents and other entities acting for the benefit of such a holder.

"Intangible transition charges." The amounts authorized to be imposed on all customer bills and collected, through a nonbypassable mechanism by the electric utility or its successor or by any other entity which provides electric service to a person that was a customer of an electric utility located within the certificated territory of the electric utility on the effective date of this chapter or that, after this effective date of this chapter, became a customer of electric services within such territory and is still located within such territory, to recover qualified transition expenses pursuant to a qualified rate order. The amounts shall be allocated to customer classes in a manner that does not shift interclass or intraclass costs and maintains consistency with the allocation methodology for utility production plant accepted by the commission in the electric utility's most recent base rate proceeding.

"Intangible transition property."

(1) The property right created under this section representing the irrevocable right of the electric utility or an assignee to receive through intangible transition charges amounts sufficient to recover all of its qualified transition expenses. The term includes all right, title and interest of the electric utility or assignee in the qualified rate order and in all revenues, collections, claims, payments, money or proceeds of or arising from intangible transition charges pursuant to the order to the extent that, in accordance with this chapter, the order and the rates and other charges authorized under the order are declared to be irrevocable.

(2) Intangible transition property shall arise and exist only when, as and to the extent that an electric utility or

assignee has qualified transition expenses for which intangible transition charges are authorized in a qualified rate order that has become effective in accordance with subsection (a) and shall thereafter continuously exist to the extent provided in the order.

"Qualified rate order." An order of the commission adopted in accordance with this section, authorizing the imposition and collection of intangible transition charges.

"Qualified transition expenses." The transition or stranded costs of an electric utility approved by the commission for recovery under sections 2804 (relating to standards for restructuring of electric industry) and 2808 (relating to competitive transition charge) through the issuance of transition bonds; the costs of retiring existing debt or equity capital of the electric utility or its holding company parent, including accrued interest and acquisition or redemption premium, costs of defeasance, and other related fees, costs and charges relating to, through the issuance of transition bonds or the assignment, sale or other transfer of intangible transition property; and the costs incurred to issue, service or refinance the transition bonds, including accrued interest and acquisition or redemption premium, and other related fees, costs and charges, or to assign, sell or otherwise transfer intangible transition property.

"Transition bonds." Bonds, debentures, notes, certificates of participation or of beneficial interest or other evidences of indebtedness or ownership which:

(1) are issued by or on behalf of the electric utility or assignee pursuant to a qualified rate order;

(2) are secured by or payable from intangible transition property; and

(3) reach final maturity in no longer than ten years.

(June 8, 2001, P.L.123, No.18, eff. July 1, 2001)

2001 Amendment. Act 18 amended subsec. (d)(1).

Cross References. Section 2812 is referred to in section 2808 of this title; section 9109 of Title 13 (Commercial Code).

§ 2813. Procurement of power.

Except as provided under the act of November 30, 2004 (P.L.1672, No.213), known as the Alternative Energy Portfolio Standards Act, the commission may not order a default service provider to procure power from a specific generation supplier, from a specific generation fuel type or from new generation only.

(Oct. 15, 2008, P.L.1592, No.129, eff. 30 days)

2008 Amendment. Act 129 added section 2813. See the preamble to Act 129 of 2008 in the appendix to this title for special provisions relating to legislative findings and declarations.

§ 2814. Additional alternative energy sources.

(a) Alternative energy sources.--The term "alternative energy sources" as defined under section 2 of the act of November 30, 2004 (P.L.1672, No.213), known as the Alternative Energy Portfolio Standards Act, shall also include 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:

(1) (i) the hydropower source has a Federal Energy Regulatory Commission licensed capacity of 21 megawatts or less; and

(ii) the license for the hydropower source was issued by the Federal Energy Regulatory Commission on or prior to January 1, 1984, and 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.

(2) 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; and

(v) protects cultural and historic resources.

(b) Biomass.--The term "biomass energy" as defined under section 2 of the Alternative Energy Portfolio Standards Act shall also include the generation of electricity utilizing by-products of the pulping process and wood manufacturing process, including bark, wood chips, sawdust and lignins in spent pulping liquors. Electricity from biomass energy under this subsection generated inside this Commonwealth shall be eligible as a Tier I alternative energy source. Electricity from biomass energy under this subsection generated outside this Commonwealth shall be eligible as a Tier II alternative energy source.

(c) Increase in Tier I.--The commission shall at least quarterly increase the percentage share of Tier I alternative energy sources required to be sold by an electric distribution company or electric generation supplier under section 3(b)(1) of the Alternative Energy Portfolio Standards Act to reflect any new biomass energy or low-impact hydropower resources that qualify as a Tier I alternative energy source under this section. No new resource qualifying as biomass energy or low-impact hydropower under this section shall be eligible to generate Tier I alternative energy credits until the commission has increased the percentage share of Tier I to reflect these additional resources.
(Oct. 15, 2008, P.L.1592, No.129, eff. 30 days)

2008 Amendment. Act 129 added section 2814. See the preamble to Act 129 of 2008 in the appendix to this title for special provisions relating to legislative findings and declarations.

§ 2815. Carbon dioxide sequestration network.

(a) Assessment.--

(1) By April 1, 2009, the department shall complete a study to identify suitable geological formations, including sites within or in proximity to the Medina, Tuscarora or Oriskany Sandstone formation for the location of a State network.

(2) By June 1, 2009, the department, in consultation with the commission, shall hire one or more independent experts pursuant to 62 Pa.C.S. Pt. I (relating to Commonwealth Procurement Code), as necessary, to conduct an assessment of the following:

(i) Estimates of capital requirements and expenditures necessary for the establishment, operation and maintenance of a State network.

(ii) The collection of data to allow a safety assessment.

(iii) An assessment of all potential risk to individuals, property and the environment associated with the geological sequestration of carbon dioxide in a State network. The assessment, which shall be completed by October 1, 2009, shall include an analysis of the following:

(A) Existing Federal and State regulatory standards for the storage of carbon dioxide.

(B) Factors contained in the United States Environmental Protection Agency's Vulnerability Evaluation Framework for Geologic Sequestration of Carbon Dioxide (EPA 430-R-08-009, dated July 10, 2008).

(C) The different types of insurance, bonds, other instruments and recommended levels of insurance which should be carried by the operator of the State network during the construction and operation of the State network.

(D) The availability of commercial insurance.

(E) Models for the establishment of a Commonwealth fund to provide protection against risk to be funded by the operator.

(b) Transmission of study and assessment.--

(1) The department shall submit the study conducted under subsection (a)(1) to the Governor, the chairman and minority chairman of the Environmental Resources and Energy Committee of the Senate, the chairman and minority chairman of the Environmental Resources and Energy Committee of the House of Representatives and the department no later than May 1, 2009.

(2) The independent expert shall submit the final assessment under subsection (a)(2) to the Governor, the chairman and minority chairman of the Environmental Resources and Energy Committee of the Senate, the chairman and minority chairman of the Environmental Resources and Energy Committee of the House of Representatives and the department no later than November 1, 2009.

(c) Department.--The following shall apply:

(1) The department shall review the assessment submitted under subsection (a)(2) and all geologic sequestration requirements associated with a State network, including geological site characterization, modeling and verification of fluid movement, corrective action, well construction, operation, mechanical integrity testing, monitoring and site closure.

(2) Following the review under paragraph (1), the department may conduct a pilot project to determine the viability of establishing a State network in this Commonwealth.

(d) Definitions.--As used in this section, the following words and phrases shall have the meanings given to them in this subsection:

"Carbon dioxide sequestration." The storage of carbon dioxide in a supercritical phase within a geological subsurface formation such as a deep saline aquifer with suitable cap rock, sealing faults and anticlines that includes compression, dehydration and leak detection monitoring equipment and pipelines to transport carbon dioxide captured by an advanced coal combustion with limited carbon emissions plant to an underground storage site. The term shall not include use of the carbon dioxide for enhanced oil recovery.

"Department." The Department of Conservation and Natural Resources of the Commonwealth.

"State network." A carbon dioxide sequestration network established on lands owned by the Commonwealth, or lands on which the Commonwealth has acquired the right to store carbon dioxide, that have been designated by the Department of Conservation and Natural Resources for the storage of carbon dioxide.
(Oct. 15, 2008, P.L.1592, No.129, eff. 30 days)

2008 Amendment. Act 129 added section 2815. See the preamble to Act 129 of 2008 in the appendix to this title for special provisions relating to legislative findings and declarations.

PENNSYLVANIA
PUBLIC UTILITY COMMISSION
Harrisburg, PA. 17105-3265

Public Meeting held June 18, 2009

Commissioners Present:

James H. Cawley, Chairman
Tyrone J. Christy, Vice Chairman
Kim Pizzingrilli
Wayne E. Gardner
Robert F. Powelson, Statement

Smart Meter Procurement and Installation — Docket No. M-2009-2092655

IMPLEMENTATION ORDER

BY THE COMMISSION:

The Pennsylvania General Assembly ("General Assembly") has directed that electric distribution companies with more than 100,000 customers file smart meter technology procurement and installation plans with the Commission for approval. 66 Pa.C.S. § 2807(f). This Implementation Order will establish the standards each plan must meet and provide guidance on the procedures to be followed for submittal, review and approval of all aspects of each smart meter plan. This Implementation Order will also establish minimum smart meter capability and guidance on the Commission's expectations for deployment of smart meters.

BACKGROUND AND HISTORY OF THIS PROCEEDING

Governor Edward Rendell signed Act 129 of 2008 ("the Act" or "Act 129") into law on October 15, 2008. The Act took effect 30 days thereafter on November 14, 2008. Among other things, the Act specifically directed that within nine months of its effective date, electric distribution companies ("EDCs") are to file, with the Commission for approval, a smart meter technology procurement and installation plan. 66 Pa.C.S. § 2807(f)(1). Each EDC smart meter plan must describe the smart meter technologies the EDC proposes to install, upon request from a customer at the customer's expense, in new construction and in accordance with a depreciation schedule not to exceed 15 years. 66 Pa.C.S. §§ 2807(f)(1) and (2). The Act also establishes a requirement for EDCs to make available to third parties direct meter access and electronic access to meter data by third parties, upon customer consent. 66 Pa.C.S. § 2807(f)(3). The Act further defines minimum smart meter technology capabilities. 66 Pa.C.S. § 2807(g). Finally, the Act establishes acceptable cost recovery methods. 66 Pa.C.S. § 2807(7).

On March 30, 2009, the Commission issued a Secretarial Letter seeking comments on a draft staff proposal and additional questions regarding EDC smart meter procurement and installation. Comments were due by April 15, 2009, with reply comments due April 27, 2009. On April 9, 2009, the Commission, at the request of several interested parties, issued a Secretarial Letter extending the comment period to April 20, 2009 and the reply comment period to April 29, 2009.

The following parties filed comments: West Penn Power Company d/b/a Allegheny Power ("Allegheny"); Citizen Power ("Citizen"); Constellation NewEnergy, Inc. ("Constellation"); Duquesne Light Company ("Duquesne"); Elster Integrated Solutions ("Elster"); The Energy Association of Pennsylvania ("EA"), Exelon Energy ("Exelon"); Metropolitan Edison Company, Pennsylvania Electric Company, Pennsylvania Power Company (collectively "FirstEnergy"); the Industrial Energy Consumers of Pennsylvania ("IECPA"); Office of Consumer Advocate ("OCA"); PECO Energy Company ("PECO"); PPL Electric Utilities Corporation ("PPL"); Sensus Metering Systems ("Sensus"); Tendril Networks, Inc. ("Trendril"); and Trilliant, Inc. ("Trilliant"). The following parties filed reply comments: Duquesne; EA; FirstEnergy; IECPA; PECO; and PPL.[1]

DISCUSSION

In this section the Commission will outline the standards each plan must meet and provide guidance on the procedures to be followed for submittal, review and approval of all aspects of each smart meter plan. This section will also establish guidance on the Commission's expectations for the deployment of smart meters, as well as minimum smart meter capabilities. This section will also describe requirements regarding access to smart meters and data. Finally, in this section the Commission will provide guidance on EDC smart meter technology cost recovery.

A. Plan Approval Process

Within nine months after the effective date of Act 129, each EDC with more than 100,000 customers is to file a smart meter technology procurement and installation plan with the Commission for approval. 66 Pa.C.S. §§ 2807(f)(1) and (6). As Act 129 became effective on November 14, 2008, the smart meter plans must be submitted on or before August 14, 2009. Each smart meter plan shall include: a summary of the EDC's current deployment of smart meter technology, if any; a plan for future deployment,

[1] Wal-Mart Stores East, LP and Sam's East Inc. filed a Petition for Extension of Time to file reply comments, which this Commission denied in a letter dated May 6, 2009. While we rejected Wal-Mart's and Sam's petition, we did receive and consider their reply comments submitted on May 1, 2009.

complete with dates for key milestones and measurable goals; and such other information as is required by this Order. The plans shall be served on the Office of Consumer Advocate, the Office of Small Business Advocate, the Office of Trial Staff, and Electric Generation Suppliers licensed to provide service in the Commonwealth.

Comments to the smart meter plans will be permitted to be filed by September 25, 2009. Following the receipt of comments, the plans will be referred to the Office of Administrative Law Judge for such proceedings as may be deemed necessary. There will be at least one technical conference scheduled for each plan during October, 2009, at which the filing EDC will present personnel with in-depth knowledge of the plan who can respond to questions regarding all aspects of the plan. The technical conference(s) shall be transcribed and the transcript(s) will become part of the record in the proceeding.[2] Any evidentiary hearings that may be necessary shall be held during November 2009.

At the conclusion of the technical conference and any evidentiary hearings that may be necessary, an initial decision will be issued resolving all issues raised in the proceeding. It is anticipated that an Initial Decision will be issued on or before January 29, 2010. Parties will be permitted to file Exceptions and Reply Exceptions as set forth in Section 5.533 of the Commission's Regulations, 52 Pa. Code § 5.533. Parties are strongly encouraged to pursue settlement opportunities during the proceeding. It is expected that the comments and technical conference(s) will promote settlement efforts.

Several parties provided comments on the staff proposal's plan approval process. The EA asserted that the plan approval process should be a collaborative process rather

[2] Any technical conference should be conducted as informally as possible, consistent with the good order of the proceedings. Lay persons will be permitted to directly ask questions of the EDC representatives, although such lay persons must be affiliated with an admitted Party of Record.

than an adversary proceeding. We note that, after smart meter plans are referred to the OALJ, the proceedings will be conducted in accordance with the Commission's Rules of Administrative Practice and Procedure. This does not mean that the plan approval process must be a contentious adversary proceeding. We encourage parties to seek collaborative solutions to issues that arise during the plan approval process. Nevertheless, due process considerations require that we preserve the right of the parties to litigate if cooperative solutions cannot be reached and obtain an adjudication from the Commission.

Several commenters, including the OCA, expressed concern that the plan approval process described in the staff proposal did not provide adequate time for review of smart meter plans. They noted that Act 129 does not prescribe the period for reviewing and approving smart meter plans. Consequently, they argued that the plan approval process can and should be extended so that the review of smart meter plans is not unduly constrained.

In addition, the OCA and other commenters asserted that the proposed plan approval process should be modified to improve coordination with other proceedings required by Act 129. They point out that, under the plan approval process as described in the staff proposal, comments would be due and technical conferences would be held during August and September, 2009. During that same period, the EDCs, the statutory advocates, the ALJs and many other interested stakeholders will be engaged in Act 129 proceedings regarding Energy Efficiency and Conservation Plan approvals. These commenters conclude that the plan approval process should be modified so that it is better integrated with Energy Efficiency and Conservation Plan approvals.

Allegheny, on the other hand, asserted that Initial Decisions should be issued quickly due to the time necessary to implement plans following their approval. In addition, Duquesne expressed its support for the plan approval process described in the staff proposal.

While the Commission agrees with the need to complete the plan approval process expeditiously, we are persuaded that the process, and its results, will be improved considerably if we extend the time period for reviewing and approving plans. We will not, however, adopt OCA's proposal as that proposal does not provide the ALJs with adequate time to prepare an initial decision following the receipt of briefs and reply briefs in December 2009.

Accordingly, as outlined above, we will require smart meter plans to be filed with the Commission on or before August 14, 2009. Comments may be filed with the Commission on or before September 25, 2009. Technical conferences will be held during October 2009, with evidentiary hearings, if necessary, to be held during November 2009, and Initial Decisions to be issued on or before January 29, 2010. Any party may file Exceptions and/or Reply Exceptions to the Initial Decisions, in accordance with Commission Regulations, before the Commission issues its final decision.

B. Smart Meter Deployment

Act 129 requires EDCs to furnish smart meter technology (1) upon request from a customer that agrees to pay the cost of the smart meter at the time of the request, (2) in new building construction, and (3) in accordance with a depreciation schedule not to exceed 15 years. 66 Pa.C.S. § 2807(f)(2). The Commission recognizes that a fully functional smart meter involves more than just the meter hardware attached to the customer's premises. A fully functional smart meter that supports the capabilities required by Act 129 and as outlined below, involves an entire network, to include the meter, two-way communication, computer hardware and software, and trained support personnel. The Commission also recognizes that it may take time for EDCs to select and install the required smart meter network components, and to train support personnel.

1. Network Development and Installation Milestones

As EDCs will need time to develop and install the entire smart meter network, the Commission is granting a network development and installation grace period of up to 30 months following plan approval. During this grace period the Commission will not require EDCs to install a smart meter at a customer's premises. However, during this grace period, the Commission will require EDCs to provide interval data capable meters, if the existing meter is not capable of providing interval data, and direct access to the customer's interval data to third-parties, such as EGSs or CSPs, upon customer request.[3] The access to this interval data should be available in real-time, if requested, and in a manner consistent with RTO requirements. In addition, EDCs will be permitted to continue to offer their already established and approved time-of-use rate programs.

The Commission also directs all covered EDCs to include in their smart meter procurement and installation plan filing a proposal for meeting specific milestones within this 30 month grace period. Each covered EDC must include a justification and its plan for meeting the following milestones:

- Assessment of needs and technological solutions.
- Selection of technologies and vendors.
- Establishment of network designs.
- Establishment of plans for training personnel.

[3] These interval capable meters are not smart meters as they will not have the capabilities outlined below in Section C of this Order. However, they are capable of providing real-time pulse data that enables the recording of usage at set intervals.

- Establishment of plans for installation, testing and rollout of support equipment and software.
- Installation, testing and rollout of support equipment and software.
- Establishment of plans to design, test and certify EDI transaction capability consistent with this order.
- Establishment of plans for installation of meters consistent with the rollout requirements described below.

Each plan must include a schedule to meet each of these milestones, as well as specific reporting deadlines when the EDC will provide this Commission with reports on the status of its plan.

Several commenters provided input regarding the proposed 18 month network development and installation grace period. Overall, the topic of an 18 month grace period was the issue that generated the most consensus. The general take on the issue was that 18 months was not nearly enough time for the EDCs to have their smart meter networks up and running. Among those holding this position was: the EA, Allegheny, PPL, FirstEnergy, PECO, and Duquesne. Specifically, PPL noted that just the selection and procurement process for the meters would take 18 months, while a separate 18 month period would be required for planning and development associated with meter data management and an additional couple of years for the installation and integration of such systems.

FirstEnergy urged the Commission to remain flexible with its timelines, due to the inherent differences of the EDCs' service territories and starting points. The EA, FirstEnergy and PECO asserted that the 18 month grace period should not commence until a vendor contract is approved. PECO anticipated delays in the marketplace due to the high number of EDCs purchasing smart meters and network equipment at the same time and suggested delaying the start of the grace period until a final vendor contract is signed and approved. The EA supports the use of key goals and milestones for each EDC and encourages flexibility of such goals, as all EDCs are unique.

It seems clear that the suggested 18 month grace period is not a sufficient amount of time for the EDCs to design and install their smart meter networks. The Commission agrees that some flexibility must be provided in the design and installation of a smart meter network, as some EDCs face greater logistical challenges than others do. Therefore, the Commission has established a period of up to 30 months for each EDC to assess its needs, select technology, secure vendors, train personnel, install and test support equipment and establish a detailed meter deployment schedule consistent with the statutory requirements. This grace period will commence upon Commission approval of an EDC's smart meter plan. This will afford each EDC more time and flexibility in the design and development process to ensure that it can meet the demands and challenges unique to each service territory.

2. Customer Request

As pointed out above, the Commission will not require EDCs to deploy smart meters until after the EDC's Commission approved network development and installation grace period ends. Once this grace period expires, each covered EDC must supply a smart meter upon request by a customer, per Act 129.

The Commission recognizes that deployment of smart meters on a piecemeal or individual basis could involve greater costs than a systematic system-wide deployment. The General Assembly recognized this as well when it included the proviso that the customer requesting the smart meter must agree to pay for the cost of the smart meter. However, the Commission does not believe it was the intent of the General Assembly for this customer to pay the entire cost of the smart meter and its supporting infrastructure.

Such a requirement would be so cost-prohibitive that no customer would request a smart meter. Furthermore, the customer would be paying for the smart meter directly and also through the EDC's cost recovery mechanism. Such a result would be an absurd, impossible and unreasonable outcome, which is contrary to the rules of statutory construction. See 1 Pa.C.S. § 1922(1). To avoid this absurd result, the Commission believes that only the incremental costs over and above the cost for system-wide deployment are to be paid by customers requesting early deployment of a smart meter.

The Commission directs each covered EDC to include in its smart meter plan a proposal to install individual smart meters in advance of the EDC's system-wide deployment and after the network installation grace period. This proposal should include an itemization of the incremental costs. If an EDC cannot provide the incremental costs at the time of its initial filing, it will have to seek Commission approval of these incremental charges prior to the expiration of the approved network grace period. If an EDC does not obtain approval of these incremental costs prior to the end of the grace period it must install individual smart meters at its own expense. Such costs are not recoverable from ratepayers.

Several commenters expressed concerns regarding the costs associated with installing smart meters at customer request pursuant to 66 Pa.C.S. § 2807(f)(2)(i). OCA agreed that a customer should pay for the incremental costs of installing a meter prior to the scheduled rollout. However, OCA does not feel that the customer should have to provide payment upfront to cover the costs, but rather the costs should be recovered through an increased customer charge on the customer's monthly bill. OCA also warns that care must be taken to ensure that the customer is not being subjected to any sort of double recovery. PECO and FirstEnergy maintain that the customer must pay these costs as a lump sum at the time of the request, as stated in Act 129.

FirstEnergy submits that 52 Pa. Code § 57.20(h) provides that "a service watt-hour meter which is removed from service shall be tested for 'as found' registration accuracy." FirstEnergy requests that the Commission provide EDCs with a blanket waiver of this requirement, as the meters are not being replaced due to any perceived malfunction and will not be put back into service. FirstEnergy posits that such a waiver will eliminate unnecessary costs associated with system-wide smart meter installation.

Duquesne states that the incremental costs to an individual customer would be astronomical because reading the new meters without having deployed the entire infrastructure would require the purchasing of trucks and the hiring of meter readers and administrative office workers to manually enter the meter reads.

The Commission interprets the Act to mean that a customer must pay the costs of installing a meter at the time of the request, and hence disagrees with OCA's assertion that the costs should be embedded in a customer charge. The EDC needs to be reimbursed for the task of installing a meter on a piecemeal basis, and the easiest way to accomplish that recovery is not through a customer charge increase, but rather by receiving an upfront payment from the customer.

As for Duquesne's worry about the incremental costs being astronomical, the Commission believes there is confusion when Duquesne says it is worried about reading meters before the new infrastructure is in place. The Commission is not requiring an EDC to do anything extraordinary during this smart meter procurement and installation grace period. The requirement to install interval capable meters during the grace period or smart meters at the request of a customer is intended to support rate structures, energy efficiency or demand response programs offered by the EDC or a third party at the request of a customer. These types of programs have been in place and offered to customers for decades. All the Commission is requiring is that EDCs facilitate these programs in a cost effective manner that provides access to the data needed to support these programs without unnecessary or unreasonable barriers. Therefore, the Commission expects the EDCs to provide a plan for supporting these programs in such a manner that does not require unreasonable or imprudent costs. Furthermore, all incremental costs that EDCs plan on recovering from a customer must first be reviewed and approved by the Commission. Staff believes these costs will be reasonable and by no means astronomical.

The Commission agrees with FirstEnergy that the costs of complying with 52 Pa. Code § 57.20(h) are unnecessary and will grant a waiver of this provision for watthour meters that are being replaced with smart meters in accordance with an approved plan. The Commission believes it would add unreasonable and unnecessary costs to require the EDCs to test every meter removed for the purposes of upgrading to a smart meter.

3. New Construction

As with all equipment, meters have a useful life. EDCs determine how much to invest in meter equipment based on its useful life and have an opportunity to depreciate that investment over the useful life of the meter. In addition, EDCs have an opportunity to recover the cost of the meter from ratepayers. Therefore, if a meter is replaced prior to the end of its useful life, the EDC will not be able to take advantage of the full depreciation of that meter or the ratepayers will pay an increased rate to cover the cost of both meters. The Commission believes that the intent of the Act's provision for installing smart meters in new construction was to avoid this waste and added expense.

Again, the Commission will not require deployment of smart meters in new construction during an EDC's approved network grace period. However, the Commission will direct all covered EDCs to develop a plan to install smart meters in new construction that is begun after the network grace period. Therefore, the Commission directs each covered EDC to include in its smart meter plan a proposal for deployment of smart meters in new construction. Such a proposal should include a plan to identify new developments and construction early enough to incorporate it into the system-wide deployment proposal.

Several parties commented on the proposed rollout of smart meters in new construction. OCA posits that smart meters should be installed on new construction from the beginning, even during the network installation grace period. OCA asserts that while the smart meters will not be fully functional, the smart meters should still be able to provide the necessary billing data. FirstEnergy, PECO and PPL disagree, noting that while the meter may be able to provide billing data, the method for providing that data may not be compatible with its existing systems. FirstEnergy does not object to providing smart meters on new construction after the grace period, provided that the Commission allows for flexibility in making the smart meters fully functional and that the customer pays the incremental costs. Duquesne asserted that installation of smart meters should be addressed in the same manner as installation at customer request. Duquesne notes that customer preference should determine which meter to install between the end of the grace period and system-wide deployment.

The Commission agrees with FirstEnergy, PECO and PPL that installation of smart meters on new construction during the grace period would not be practical or cost-effective as the EDCs will not have selected the technology they will employ. Furthermore, the smart meter may not be compatible with its existing meter reading technology. As such, the Commission directs EDCs to handle any new construction customer that requests a smart meter during the grace period pursuant to the procedures addressed above for customer requested meters.

4. System-Wide Deployment

The Commission believes that it was the intent of the General Assembly to require all covered EDCs to deploy smart meters system-wide when it included a requirement for smart meter deployment "in accordance with a depreciation schedule not to exceed 15 years." It is this system-wide deployment that will provide the foundation for the EDCs' smart meter installation plans. Therefore, it is crucial for the EDCs to develop a plan that will best meet the needs of their service territory, while at the same time operating in a manner that is both cost and time effective.

The EDCs shall detail their system-wide deployment plans to the Commission, including any type of tiered rollout the company proposes, as well as the associated costs and benefits incurred from such a rollout. This system-wide plan should also incorporate a coordination element with the new construction deployment component. Furthermore, the Commission will require all EDCs to file a "Smart Meter Progress" report on an annual basis that will update the status of their installation plans, including the number of customers who received meters in the prior year, the estimated number of customers scheduled to receive meters in the coming year, and all costs associated with the meter plan incurred during the previous year.

It should also be noted that Act 129 uses the language "not to exceed 15 years." An EDC is encouraged to expedite the deployment process if it will provide increased customer benefits in a cost-effective manner. Again, the primary goal of the EDC deployment plan should be to implement a deployment and installation schedule that best balances the overall efficiency and timeliness of the smart meter installations with the costs incurred.

OCA commented that the Commission needs to clarify whether the 15 year depreciation schedule outlined in Act 129 commences upon plan approval or following the grace period. The Commission believes that the 15 year depreciation period should commence upon plan approval, and that the grace period is simply a period of time within that 15 year timeframe.

C. Smart Meter Capabilities

Act 129 defines smart meter technology as including metering technology capable of bidirectional communication that records electricity usage on at least an hourly basis, including related electric distribution system upgrades to enable the technology. 66 Pa.C.S. § 2807(g). The Act further states that the smart meter technology must provide customers with direct access to and use of price and consumption information, to include, (1) direct information on their hourly consumption, (2) enable time-of-use rates and real-time price programs, and (3) effectively support the automatic control of electricity consumption by, the customer, the EDC or a third-party, at the customer's request. 66 Pa.C.S. § 2807(g).

The Act further requires that default service providers submit time-of-use rates and real-time pricing plans by January 1, 2010, or at the end of the applicable generation rate cap period, whichever is later. Default service providers must offer the time-of-use rates and real-time pricing plans to all customers that have been provided with smart meter technology. 66 Pa.C.S. § 2807(f)(5). Real-time pricing is defined as "a rate that directly reflects the different cost of energy during each hour." 66 Pa.C.S. § 2806.1(m). A time-of-use rate is defined as "a rate that reflects the costs of serving customers during different time periods, including off-peak and on-peak periods, but not as frequently as each hour." *Id.*

The Commission believes that the smart meter capability requirements set out in Act 129 are minimal requirements. The Commission also recognizes that smart meter technology can support more than demand response and pricing programs. Smart meters have the ability to support maintenance and repair functions, theft detection, system security, consumer assistance programs, customer-generator net metering, and other programs that increase an EDC's efficiencies and reduce operating costs. Therefore, the Commission directs that a covered EDC's smart meter technology must support the following capabilities:

1. Bidirectional data communications capability.
2. Remote disconnection and reconnection.
3. Ability to provide 15-minute or shorter interval data to customers, EGSs, third-parties and the regional transmission organization ("RTO") on a daily basis, consistent with the data availability, transfer and security standards adopted by the RTO.
4. A minimum of hourly reads delivered at least once per day.
5. On-board meter storage of meter data that complies with nationally recognized non-proprietary standards such as ANSI C12.19 and C12.22 tables.
6. Open standards and protocols that comply with nationally recognized non-proprietary standards, such as IEEE 802.15.4.
7. Ability to upgrade these minimum capabilities as technology advances and becomes economically feasible.
8. Ability to monitor voltage at each meter and report data in a manner that allows EDC to react to the information.
9. Remote programming capability.
10. Communicate outages and restorations.
11. Ability to support net metering of customer-generators.

12. Support automatic load control by EDC, customer and third-parties, with customer consent.
13. Support time-of-use and real-time pricing programs.
14. Provide customer direct access to consumption and pricing information.

While the Commission believes that all of the above-listed capabilities will further facilitate the consumer's ability to intelligently control their electric use and costs, we are cognizant that the costs of some of these added capabilities may exceed any benefit they may provide. Therefore, the Commission reserves the authority to waive the requirement for any of the Commission imposed requirements as described in Section E.1 below. This waiver authority does not extend to the minimum requirements delineated in 66 Pa.C.S. § 2807(g).

Several commenters provided input regarding the smart meter capabilities listed in the staff proposal. We will address each of the major issues raised by commenters relating to smart meter capabilities.

1. Remote disconnect, reconnect, service limiting and pre-pay capabilities

In their comments, Allegheny and PECO favor requiring smart meters to support remote disconnect and reconnect, as well as service limiting and prepaid service programs. Duquesne supported remote disconnect and reconnect for single phase, self-contained and class 200 or less meters, but suggested that revisions to Chapter 56 need to be considered before committing to these capabilities. PPL noted that there are institutional impediments to deployment of remote disconnect and reconnect capability. In addition, PPL and OCA noted that remote disconnect and reconnect, as well as, service-limiting and pre-pay functionality involves significant public policy considerations that raises process and safeguard issues. OCA is further concerned that by requiring smart meters to support remote disconnect, service limiters and prepaid service sends a strong signal to EDCs to implement these capabilities. OCA specifically stated that "the use of smart meter technology to terminate customers, limit service, or require prepayment of service raise significant concerns for the health and safety of the residents of the Commonwealth."[4]

The Commission agrees in part with Allegheny, OCA, PECO and PPL. Specifically, the Commission agrees that the significant policy implications of service limiting and prepaid service should be addressed in another proceeding prior to requiring such capability in smart meters. Therefore, we have removed support for service-limiting, and prepaid service as a minimum capability requirement. This does not preclude EDCs from including these capabilities, however, an EDC cannot employ these capabilities unless it is approved by the Commission and consistent with regulations governing such programs, such as 52 Pa. Code § 56.17.

The Commission does not believe that the same policy uncertainties exist with regard to remote disconnect and reconnect. The policy issues and procedures regarding termination and reconnection of service are addressed in the Public Utility Code ("Code"), at 66 Pa.C.S. §§ 1401-1418 and this Commission's regulations. Requiring the ability to remotely disconnect and reconnect service in no way abrogates an EDC's obligation to adhere to the Code or this Commission's regulations. Therefore, the Commission will require that smart meters have a capability to remotely disconnect and reconnect service as it provides the ability to increase safety, efficiency and cost benefits.

[4] OCA Comments at page 10.

Ability to provide 15-minute reads

Duquesne, FirstEnergy, PECO, PPL and OCA do not support the inclusion of 15-minute or shorter interval data capability. Instead the parties support hourly data intervals. Duquesne supports hourly and real time pulse data. OCA and PECO assert that the 15-minute or shorter requirement goes beyond Act 129. PECO notes that this requirement is not practical or useful for residential or small commercial customers and that mandating collection of this data may result in increased costs with no benefits. PPL adds that there is less need today than in the past for 15-minute interval data as settlements are conducted on an hourly basis.

However, PPL also recognized that some demand side management programs require less than hourly data intervals. To accommodate this limited group of customers, PPL recommended that the Commission direct that EDC Smart Meter Plans demonstrate how this need will be met. An example offered by PPL involves access protocols for parties to obtain pulse data when hourly data is not sufficient.

Constellation, Elster and Trilliant support the inclusion of the 15-minute or shorter interval data capability. Constellation contends that each meter should be programmable so that a 1-, 5-, 15-, 30- or 60-minute interval could be set. This interval should be based on customer requirements rather than administratively set by the Commission. Elster notes that typical residential systems are capable of providing 15-minute interval data. The interval selected may be more or less frequent depending on specific utility application. Trilliant adds that systems should be configurable to intervals between 5- and 60-minutes. Elster, however, notes that the shorter data intervals will increase costs.

The Commission agrees with Constellation, Elster and Trilliant and concludes that the ability to provide 15-minute or shorter interval data is appropriate. We stress however, that the ability to provide 15-minute or shorter interval data does not mean that EDCs must collect this data on all customers at all times. The ability to provide 15-minute or shorter interval data will allow for EDCs and third parties with customer consent to offer and support rate plans that utilize this level of granularity. The Commission will therefore require that EDC smart meter plans demonstrate how the need for 15-minute or shorter data intervals will be met.

2. Meter storage

Duquesne supports on board meter storage of meter data that complies with nationally recognized non-proprietary standards without specifying one particular standard. FirstEnergy supports ANSI C12.22 and C12.19 or their equivalents. PPL indicates that standards should be followed as appropriate, but questions why it is necessary to follow standard protocol for storage in the meter that is unlikely to be communicated anywhere but the EDC repository.

The Commission agrees with FirstEnergy and has added the ANSI C12.22 standard. The ANSI C12.19 and C12.22 are standards for storage and transport of register data over a network. The Commission is aware that a number of factors including memory size, number of data channels being recorded and interval length can impact the number of storage days. The intent of a minimum number of storage days is to ensure that adequate monthly billing data is retrieved before the data is overwritten. Therefore, rather than reference a specific number of days, the Commission requires that EDC smart meter plans incorporate provisions ensuring that all billing data is retrieved before data is overwritten and recoverable following communications outages.

3. Open standards and protocols

Tendril suggests that the Commission should accept any nationally recognized, non-proprietary standard. Trilliant adds that protocols should be focused at a high level, such as IEEE 802.15.4 (open standard for radio technology). Allegheny notes, for example, that ZigBee is built upon this standard. Elster, however, emphasizes that there is more than one protocol. Duquesne cites the existence of 14 HAN solutions, open or otherwise. The Commission agrees that protocols should be focused at a high level, such as IEEE 802.15.4, and therefore, directs compliance with this standard. The Commission also encourages EDCs to adopt other open protocols and standards that enhance interoperability that are developed subsequent to this order, to the extent available at the time the vendor contract is solicited.

4. Upgradability

Duquesne suggests that technology should be evaluated to accommodate future upgrades, noting that some capabilities can be upgraded as technology advances and becomes economically feasible, while other capabilities are costly to implement without complete meter and system replacement. Duquesne emphasizes that it is difficult to implement a system now to accommodate unknown technical advances. Similarly, PPL notes that it is more important to build flexibility into smart meter systems than it is to anticipate every future need.

The Commission agrees with Duquesne that some capabilities can be upgraded as technology advances and becomes economically feasible, while other capabilities are costly to implement without complete meter and system replacement. The Commission, therefore, directs that EDC smart meter plans identify capabilities that have the potential to be upgraded without complete system replacement as technology advances and becomes economically feasible.

5. Ability to monitor voltage

PPL asserts that it is premature to assume that voltage monitoring has value and that an operations management system and remotely controlled equipment exists to make use of the data. PPL adds that this capability may be appropriate in certain evolutions of the smart grid. The Commission disagrees with PPL in that this feature will serve to enhance reliability aspects associated with the grid. The Commission, therefore, will require that smart meters have a capability to support the ability to monitor voltage.

6. Direct access to consumption and pricing information

Allegheny noted that most smart metering vendors support two standards for a home-area-network ("HAN") protocols, proprietary and ZigBee. Duquesne recommended that usage information should be validated and made available within 48 hours through a HAN or internet. Duquesne also recommended that the pricing information should reflect the tariff rate and be made available through the internet or HAN. FirstEnergy commented that pricing information should be provided through the internet, noting that HAN type devices will be a competitive offering that should not be dictated by regulation. FirstEnergy and PECO also recommended that validated usage data should be made available in a minimum of 48 hours. PECO posits that data from the meter to a HAN device be limited to raw consumption data. Tendril comments that the Commission should not establish a single standard protocol for delivery of usage information, noting that this information should be available through any and all means that match customer preferences. Regarding pricing data, Tendril encourages a reliance on open standards such as the Smart Energy Profile data standard established by the ZigBee Alliance.

Regarding the comments related to validated consumption data, the Commission agrees in part with FirstEnergy and PECO. We accept that this data should be made available to customers or their designated third-parties within 48 hours, but we adopt this as a minimum standard, at least initially. Ideally, as noted by various parties, the information should be available the next day. Allegheny has already proposed to do this in 24 hours and FirstEnergy noted a 48 hour delay could be shortened as experience is gained.

Regarding comments on the use of open standards and protocols for meter connectivity with other devices, the Commission will not require compliance with one set of standards. Nor will we establish a new standards working group but will instead allow the industry to continue to develop uniform standards for communications firmware and software that would impact consumer products and services in the marketplace. However, the Commission will require EDC smart meters to have a capability to provide raw near real-time consumption data through a HAN or similarly capable method with open protocols. This delivery method should also be capable of providing pricing signals to support real-time and time-of-use pricing programs, as well as energy efficiency and demand response programs. Smart meters should support EDC and EGS time-of-use and real-time-pricing programs. Similarly, smart meters should support EDC, EGS and CSP energy efficiency and demand response programs. An EDC should not use these systems to gain competitive advantage for only its pricing and demand response programs.

D. Access to Smart Meters and Data

Act 129 requires EDCs to make available to third parties, including electric generation suppliers and providers of conservation and load management services, with customer consent, direct access to the meter and electronic meter data. 66 Pa.C.S. § 2807(f)(3). The Commission believes that the true usefulness of smart meters is to provide information to empower customers to control their electric use, for knowledge itself is power.[5]

In order for customers to be empowered they, or their designated representatives, must have direct access to their consumption data and price data. Therefore, the Commission directs that all covered EDCs must provide at least the following access to their smart meters and data:

1. Non-discriminatory access for retail electric suppliers and third-parties, such as EGSs, and conservation and load management service providers;
2. Open, non-proprietary two-way access for electric suppliers and third-parties, such as EGSs, and conservation and load management service providers; and
3. Full electronic access to customers and their representatives to meter data upon customer consent.

The Commission further directs that each EDC plan must address standards and formats for electronic data communications with customers and third parties. There are many approaches for requesting and providing meter-level data today, e.g. electronic bulletin board, pass-key protected websites, compact disk, etc. In addition, EDI (ASC X12 standards) capability has been built by the electricity industry in the Commonwealth to facilitate a reliable, secure economic approach for communicating verified customer

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[5] Francis Bacon.

data for electric choice. Regardless of the standard or format identified, compliance with Commission orders relating to electronic data communications and the approved Internet protocol at Docket No. M-00960890F0015, is required for third-party access to verified EDC meter data. The third-party must be EDI tested and certified with the EDC and is free to transcribe that data into any format to meet the customer's specific needs.

In order to achieve the capabilities of smart meter technology, however, EDCs are required to implement an EDI transaction relating to enrollment of customers who elect service on a real-time-price or time-of-use rate program, and a new historical interval usage transaction in order to provide customers and their designated agents with 12 months of interval usage data pursuant to Commission orders at Docket No. M-00960890F0015. Also, the historical usage data transaction must facilitate third-party exchange of historical interval usage data recorded at the meter level. An EDI transaction will also need to be developed and implemented for the exchange of monthly, billing quality, interval usage data recorded at the meter level versus the current practice of providing usage data at the account level. These and other developments necessary for the implementation of smart meter technology plans require EDC and third-party participation in the Commission's Electronic Data Exchange Working Group ("EDEWG"). Therefore, EDCs are directed to propose EDI capabilities for this purpose through the EDEWG for Commission review no later than January 1, 2010. In developing these proposals, EDCs are encouraged to look at any applicable national standards, such as those developed by the North American Energy Standards Board. EDCs shall identify in their plans target dates for the testing and certification of these EDI transactions with their business partners in order to meet the smart metering implementation deadline as specified in this Order.

In general, most commenters who addressed the direct meter access issue agree that allowing direct access to the meter itself raises security and safety concerns. PPL commented that communications are separate from metering company responsibilities and is concerned that the term "direct access" can be interpreted as direct access to raw unvalidated data. Citizen stated that smart meter information should be accessible to customers from a website and directly from the meter, if not cost prohibitive. Duquesne supports direct access to and use of price and consumption information, but does not support direct access to its meters for security reasons. FirstEnergy posits that access to the meter should be strictly prohibited, but that access to the meter data should be permitted under conditions that protect privacy and security. FirstEnergy also encourages the adoption of nationally recognized standards and protocols. PECO expressed a concern about network security and management risks and does not want a mandate that provides customers and third-parties unrestricted access to the EDC's metering network.

Constellation noted that curtailment service providers and EGSs require direct access to the meter to poll interval data and that should not be burdened by installing their own equipment to collect this data. Exelon suggests that there should be consistency across service territories regarding technological capabilities, protocols and processes. Tendril commented that direct, near real-time access to information is critical and that it is extremely important to accommodate two-way communication through the meter interface.

In response to comments on this issue, the Commission interprets the phrase, "make available direct meter access and electronic access to customer meter data," at 66 Pa.C.S. § 2807(f)(3), as the customer's or customer designated third-party's ability to receive price and meter data in a timely manner and format that is useful and beneficial to the customer in terms of cost and value. Examples of customer benefits from direct access may include, but not be limited to, direct load control, automated appliance control and demand response pricing through the grid.

Additionally, the Commission notes that the EDC, who owns the meter, is responsible for providing direct access through the installation of a smart meter and infrastructure that will enable the end user to receive metered price and consumption information, at least in near real-time and in a format that is not proprietary or unduly discriminatory. Many industry standards groups are engaged in addressing and defining business practices and requirements for smart metering products, services and open data communications that will preserve the integrity, reliability and security of the national grid, the local distribution system and the consumer's data. The National Institute of Standards Technology, the North American Energy Standards Board, and the Utility Communications Architecture International Users Group are worthy of EDC participation for achieving the smart metering requirements of Act 129. Therefore, we direct EDCs to adhere to common industry and communications standards for providing consumers direct access to smart meters and data pursuant to this Order.

Nevertheless, for security reasons we determine that a distinction should be made between access to the physical meter and access to the meter information, and we will not require EDCs to allow customers and their designated agent to tamper or physically access the meter itself. However, this directive is not intended to preclude third-parties, with customer consent, from obtaining raw meter data through meter pulse leads, a secure web-portal or other secure means reasonably available to the customer or designated third-party. We agree with the OCA and Sensus that some residential and small commercial customers may find it beneficial to receive consumption and pricing information, and in this regard we will require all EDCs to install a smart meter that is capable of communicating raw data on at least a near real-time basis to in-home devices installed by the customer or customer designated agent. Additionally, we will require EDCs to provide all customers and their designated third-parties access to the following: validated, bill quality consumption data within 48 hours of the meter read; written detailed disclosure of data definitions and characteristics; and written update notices of changes in data characteristics as the changes become effective.

E. EDC Cost Recovery

Act 129 allows an EDC to recover reasonable and prudent costs of providing smart meter technology, to include annual depreciation and capital costs over the life of the smart meter technology and the cost of any system upgrades required to enable the use of the smart meter technology, incurred after November 14, 2008, less operating and capital cost savings realized by the electric distribution company from the installation and use of the technology. Smart meter technology is deemed to be a new service offered for the first time under Section 2804(4)(vi).

1. Cost Recovery Mechanism

An EDC may recover smart meter technology costs through (1) base rates, including a deferral for future base rate recovery of current basis with carrying charge as determined by the Commission; or (2) on a full and current basis through a reconcilable automatic adjustment clause under Section 1307. 66 Pa.C.S. § 2807(f)(7). However, in no event shall lost or decreased revenues by an EDC due to reduced electricity consumption or shifting energy demand be considered a cost of the smart meter technology recoverable under a reconcilable automatic adjustment clause under Section 1307(b), except that decreased revenues and reduced energy consumption may be reflected in the revenue and sales data used to calculate rates in a subsequent distribution rate base rate proceeding filed under Section 1308 (relating to voluntary change in rates), or a recoverable cost. 66 Pa.C.S. § 2807(f)(4).

Act 129 allows an EDC to recover "all reasonable and prudent costs of providing smart meter technology." In order to determine what these costs are, each EDC will document all costs relating to its smart meter deployment and installation plan. These costs will include both capital and expense items relating to all plan elements, equipment and facilities, as well as an analysis of all related administrative costs. More specifically, these costs would include, but not be limited to, capital expenditures for any equipment and facilities that may be required to implement the smart meter plan, as well as depreciation, operating and maintenance expenses, a return component based on the EDC's weighted cost of capital, and taxes. Administrative costs would include, but not be limited to, incremental costs relating to plan development, cost analysis, measurement and verification, and reporting. In addition, the plan should include cost estimates for testing, upgrades, maintenance and personnel training. The EDC must also provide sufficient support to demonstrate that all such costs are reasonable and prudent with respect to its smart meter plan. Consistent with Section 315(a), the burden of proof shall be on the EDC. 66 Pa.C.S. § 315(a).

The Commission recognizes that some of the requirements for smart meters outlined in Section C of this Order go beyond the minimum requirements set forth in Act 129. In order to ensure that these additional smart meter functions are cost-effective, we direct that each smart meter plan filing include cost data that quantifies the costs to meet the minimum requirements set forth in Act 129, the costs to meet all of the requirements set forth in Section C above, and the individual incremental costs of each added function, less any operating and capital cost savings. Specifically, we direct that the plan filing shall quantify the costs to deploy and operate smart meter technology that is capable of the following minimum requirements set forth in 66 Pa.C.S. § 2807(g):

- Bidirectional data communications.
- Recording usage data on at least an hourly basis once per day.

- Providing customers with direct access to and use of price and consumption information.
- Providing customers with information on their hourly consumption.
- Enabling time-of-use rates and real-time price programs.
- Supporting the automatic control of the customer's electric consumption.

In addition, each plan filing shall include the individual incremental costs for deploying and operating the following smart meter technology capabilities:

- Ability to remotely disconnect and reconnect.
- Ability to provide 15-minute or shorter interval data to customers, EGSs, third-parties and an RTO on a daily basis, consistent with the data availability, transfer and security standards adopted by the RTO.
- On-board meter storage of meter data that complies with nationally recognized non-proprietary standards such as ANSI C12.19 and C12.22 tables.
- Open standards and protocols that comply with nationally recognized non-proprietary standards, such as IEEE 802.15.4.
- Ability to upgrade these minimum capabilities as technology advances and becomes economically feasible.
- Ability to monitor voltage at each meter and report data in a manner that allows an EDC to react to the information.
- Ability to remotely reprogram the meter.
- Ability to communicate outages and restorations.
- Ability to support net metering of customer-generators.

The deployment and operating costs to be presented shall include a breakdown of all incremental costs and any associated potential operational and maintenance cost savings for each functionality and configuration. All cost estimates must be supported by estimates from at least two vendors where available. To the extent that an EDC or another party demonstrates that a particular Commission imposed requirement is not cost-effective, the Commission will have the option of waiving a particular requirement for that EDC or all EDCs. This waiver authority does not extend to the minimum requirements delineated in 66 Pa.C.S. § 2807(g). Any EDC that is unable to provide this cost data with its August 14, 2009 filing can petition the Commission for permission to file such data at a later date. Any such filing shall include a proposed filing date.

Furthermore, the Commission recognizes that consideration of these cost issues may benefit from further discussion prior to the August 14, 2009, filing deadline. In order to facilitate this discussion, the Commission will convene a stakeholder meeting no later than July 17, 2009.

The Commission will allow each EDC to develop a reconcilable adjustment clause tariff mechanism in accordance with 66 Pa.C.S. § 1307 and include this mechanism in its smart meter plan. Such a mechanism shall be designed to recover, on a full and current basis from each customer class, all prudent and reasonable smart meter costs less operating and capital cost savings realized by the EDC from the installation and use of smart meter technology. The mechanism shall be set forth in the EDC's tariff, accompanied by a full and clear explanation as to its operation and applicability to each customer class. The tariff mechanism will be subject to an annual review and reconciliation in accordance with 66 Pa.C.S. § 1307(e). Such annual review and reconciliation will be scheduled to coincide with the submission of the "Smart Meter Progress" annual report outlined in Section B.1 above.

2. Allocation of Costs to Customer Classes

The Commission will require that all measures associated with an EDC's smart metering plan shall be financed by the customer class that receives the benefit of such measures. In order to ensure that proper allocation takes place, it will be necessary for the utilities to determine the total costs related to their smart metering plans, as discussed in E.1. Once these costs have been determined, we will require the EDC to allocate those costs to the classes whom derive benefit from such costs. Any costs that can be clearly shown to benefit solely one specific class should be assigned wholly to that class. Those costs that provide benefit across multiple classes should be allocated among the appropriate classes using reasonable cost of service practices.

OCA stated that it feels traditional rate base procedures would be the preferred method for recovery, rather than an adjustment mechanism that may be unnecessarily complicated. OCA also says that if an adjustment mechanism is used only reasonable net costs should be included in the surcharge. PECO, FirstEnergy, and EA counter by asserting that including the costs in base rates is the best method for cost recovery. PECO asserts that an EDC should use whatever method it sees fit, as the Act allows for recovery through either method, noting its belief that the methods are not mutually exclusive. FirstEnergy states that OCA's claim that base rates are the preferred method of recovery is premature and that EDCs deserve the chance to design and submit a plan for recovery before it is rejected.

A number of commenters agree that care should be taken to ensure the proper allocation of costs amongst customer classes. IECPA recommends that the Commission should allow any customer or customer class that has previously paid to have smart meters installed to be exempt from all costs of the smart meter program. EA strongly objects to that recommendation, saying that a fully functional smart meter involves an entire network and that these comments ignore the costs of upgrading the systems that support smart meters. They go on to note that eliminating an entire class from paying its share of reasonable costs before the submission of a single smart meter plan is premature, ignores the policy underlying Act 129, and undercuts the role of the Commission in reviewing and approving cost recovery mechanisms. Finally, EA, PECO and Duquesne suggested that under-depreciated abandoned assets need to be recovered as stranded costs and that the Commission should allow for accelerated depreciation of assets that are retired early.

The Commission believes the EDCs should install smart meters in a manner that coincides with the full depreciation of existing meters, so as to minimize the stranded costs. However, in the event that there are stranded costs that need to be recovered the Commission agrees with EA, PECO and Duquesne that the EDCs should be allowed to seek recovery of those costs through an accelerated depreciation schedule, to be included in the EDC's cost recovery plan.

The Commission also agrees with FirstEnergy that it is premature to deem one method of recovery preferable to another. The Commission interprets 66 Pa.C.S. § 2807(f)(7) as permitting an EDC to use either method of cost recovery at its discretion.

The Commission disagrees with IECPA's basic premise that a customer or entire customer class should be exempt from all costs associated with these smart meter plans. We agree with the EA that it is premature to suggest such a blanket exemption.

CONCLUSION

This Implementation Order establishes the Commission's smart meter technology procurement and installation standards each EDC with greater than 100,000 customers must meet. This Order also provides guidance on the procedures to be followed for submittal, review and approval of all aspects of each smart meter plan. In addition, it establishes the minimum smart meter capabilities and guidance on deployment of smart meter technology. We extend our thanks to those who participated by providing comments on this important and timely energy program. We would especially like to note our appreciation for the cooperation and courtesy extended by all, which was essential in meeting the aggressive timelines established by the General Assembly for Act 129 implementation. **THEREFORE,**

IT IS ORDERED:

1. That the Commission establishes specific smart meter technology minimum capabilities and procedures for submittal, review and approval of all aspects of each smart meter plan to include cost recovery.

2. That electric distribution companies with greater than 100,000 customers adhere to the guidelines for smart meter technology procurement and installation identified in this Implementation Order.

3. That the Director of Operations convene a stakeholder meeting no later than July 17, 2009, to discuss issues related to the costs and benefits associated with the Commission imposed smart meter capability requirements.

4. That all electric distribution companies that are required to file a smart meter technology procurement and installation plan file such a plan consistent with the directives contained in this order by August 14, 2009.

5. That all electric distribution companies that are required to install smart meter technology are exempt from compliance with 52 Pa. Code § 57.20(h) for testing watthour meters that are being replaced with smart meters in accordance with an approved smart meter technology procurement and installation plan.

6. That all EDCs may recover the reasonable and prudent costs of providing smart meter technology in accordance with the procedures set forth in this Implementation Order.

7. That this Implementation Order be published in the *Pennsylvania Bulletin* and served on the Office of Consumer Advocate, Office of Small Business Advocate, Office of Trial Staff, all jurisdictional electric distribution companies and all parties that filed comments under this docket.

BY THE COMMISSION

James J. McNulty
Secretary

(SEAL)

ORDER ADOPTED: June 18, 2009

ORDER ENTERED: June 24, 2009

EXHIBIT
PD-3

PENGAD 800-631-6989

PENNSYLVANIA
PUBLIC UTILTY COMMISSION
Harrisburg, PA 17105-3265

Public Meeting held June 30, 2011

Commissioners Present:

Robert F. Powelson, Chairman
John F. Coleman, Jr., Vice Chairman, Statement
Tyrone J. Christy
Wayne E. Gardner
James H. Cawley

Petition of West Penn Power Company	:	
d/b/a Allegheny Power for Expedited Approval	:	M-2009-2123951
of its Smart Meter Technology Procurement	:	
and Installation Plan	:	

ORDER

BY THE COMMISSION:

We adopt as our action the Initial Decision on Remand of Administrative Law Judge Mark A. Hoyer, dated May 3, 2011;

THEREFORE,

IT IS ORDERED:

That the unopposed Amended Joint Petition for Settlement of All Issues filed by West Penn Power Company d/b/a Allegheny Power is granted without modification.

BY THE COMMISSION

Rosemary Chiavetta

Rosemary Chiavetta
Secretary

(SEAL)

ORDER ADOPTED: June 30, 2011

ORDER ENTERED: June 30, 2011

EXHIBIT
PENGAD 800-631-6989
PD-4

PENNSYLVANIA
PUBLIC UTILITY COMMISSION
Harrisburg, PA 17105-3265

Public Meeting held June 5, 2014

Commissioners Present:

Robert F. Powelson, Chairman
John F. Coleman, Jr., Vice Chairman
James H. Cawley
Pamela A. Witmer
Gladys M. Brown

Joint Petition of Metropolitan Edison Company, Pennsylvania Electric Company, Pennsylvania Power Company and West Penn Power Company For Approval of Their Smart Meter Deployment Plan	M-2013-2341990 M-2013-2341991 M-2013-2341993 M-2013-2341994

OPINION AND ORDER

BY THE COMMISSION:

Before the Pennsylvania Public Utility Commission (Commission) for consideration and disposition is the Revised Smart Meter Deployment Plan (Revised Deployment Plan) of Metropolitan Edison Company (Met-Ed), Pennsylvania Electric Company (Penelec), Pennsylvania Power Company (Penn Power) and West Penn Power Company (West Penn) (collectively, the Companies or FirstEnergy) filed on March 19, 2014, pursuant to the Commission's March 6, 2014, Opinion and Order (March 6 Order). In accordance with the Commission's Secretarial letter issued on April 16, 2014, Administrative Law Judge (ALJ) Elizabeth H. Barnes certified the record in this proceeding on May 15, 2014. For the reasons stated below, we shall approve the Revised Deployment Plan proposed by FirstEnergy consistent with this Opinion and Order.

I. Background

On October 15, 2008, Act 129 was signed into law and was codified as part of the Public Utility Code (Code), 66 Pa. C.S. § 2806.1, *et seq.* Act 129 became effective on November 14, 2008, and required Electric Distribution Companies (EDCs) with at least 100,000 customers to present a Smart Meter Technology Procurement and Installation Plan (SMP Plan) to the Commission for approval. 66 Pa. C.S. § 2807(f). Specifically, Section 2807(f)(2) directed EDCs to furnish smart meter technology as follows: 1) upon request from a customer that agrees to pay the cost of the smart meter at the time of the request; 2) in new building construction; and 3) in accordance with a depreciation schedule not to exceed fifteen years. 66 Pa. C.S. § 2807(f)(2).

The Commission issued an Order on June 24, 2009, to establish standards and provide guidance for implementing the requirements of Act 129.[1] Pursuant to Section 2807(f) of the Code, 66 Pa. C.S. § 2807(f), Met-Ed, Penelec and Penn Power (collectively, the FirstEnergy Companies) filed their Joint Petition for Approval of Smart Meter Technology Procurement and Installation Plan (2009 SMP) on August 14, 2009. By Order entered on June 9, 2010, the Commission approved the 2009 SMP of the FirstEnergy Companies with modifications. The Commission noted that these Companies expected to file their full Deployment Plan by April 2012.[2]

Also on August 14, 2009, West Penn filed a Smart Meter Implementation Plan (WPP SMP) separately from the three FirstEnergy Companies. During the Commission's review of the WPP SMP, Met-Ed's, Penelec's and Penn Power's ultimate

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1 *In Re: Smart Meter Procurement and Installation*, Docket No. M-2009-2092655 (Order entered June 24, 2009) *(Implementation Order).*

2 *Joint Petition of Metropolitan Edison Company, Pennsylvania Electric Company and Pennsylvania Power Company for Approval of Smart Meter Technology Procurement and Installation Plan*, Docket No. M-2009-2123950 (Order entered June 9, 2010).

corporate parent, FirstEnergy Corp., and West Penn's corporate parent, Allegheny Energy, Inc., announced their intent to merge. As a result, the WPP SMP filing was reassessed. On June 30, 2011, the Commission approved a Joint Petition for Settlement of All Issues (WPP Settlement) regarding the WPP SMP. *Petition of West Penn Power Company for Expedited Approval of its Smart Meter Technology Procurement and Installation Plan*, Docket No. M-2009-2123951 (Order entered March 9, 2011).[3] In the WPP Settlement, West Penn agreed to file its full Deployment Plan as part of its revised WPP SMP with the Commission by June 2012.

II. History of the Proceeding

On May 25, 2012, the Companies requested an extension for the filing of their Smart Meter Deployment Plan to the end of 2012, in order to evaluate new smart meter technologies. The Commission granted that request by Secretarial Letter dated June 28, 2012.

On December 31, 2012, the Companies filed a Joint Petition for approval of their Smart Meter Deployment Plan (Deployment Plan), in which they requested that the Commission: (1) find that their proposed Deployment Plan satisfies the requirements of Act 129 and the Commission's *Implementation Order*; (2) approve the Companies' proposed procurement and deployment of approximately 2.1 million smart meters, over 98% of which should be installed by the end of 2019; (3) authorize the Companies to continue to recover smart meter costs through their previously approved Smart Meter Technologies Charge (SMT-C) Riders, including $5.1 million of costs incurred by West Penn in anticipation of the installation of smart meters; and (4) authorize the Companies

[3] The Commission adopted the Initial Decision of the ALJ and approved the WPP Settlement by Order entered June 30, 2011, at Docket No. M-2009-2123951.

to create a regulatory asset for their investment in their existing meters (Legacy Meters) to be replaced by smart meters.

On February 7, 2013, Petitions to Intervene were filed by Direct Energy Services, LLC (Direct) and collectively on behalf of the Met-Ed Industrial Users Group, the Penelec Industrial Customer Alliance, the Penn Power Users Group, and the West Penn Power Industrial Intervenors (collectively, the Industrial Customer Groups). The following day, the Office of Consumer Advocate (OCA) submitted Comments and an Answer to the Joint Petition. On February 14, 2013, the Office of Small Business Advocate (OSBA) filed a Notice of Intervention.

An evidentiary hearing was held in Harrisburg on May 8, 2013, at which time the Companies' witnesses were presented for oral rejoinder and cross examination and the OCA witness was presented and cross-examined. Also, the Companies and Direct submitted a document entitled "Joint Stipulation of Position," that was admitted as Direct Energy Hearing Exhibit 1, and was intended to resolve certain notification issues raised by Direct. Finally, and by agreement of the Parties, the record was held open to allow the Companies to submit copies of a table that originally appeared in the OCA's surrebuttal testimony, but was later removed and replaced by the OCA at the May 8, 2013 hearing (Joint Petitioners' Cross Examination Exhibit 2). This late exhibit was filed on May 13, 2013. Main Briefs were filed on May 24, 2013, by the Companies and the OCA and Reply Briefs were filed on June 3, 2013, by the same Parties. The record was closed on June 3, 2013.

By Recommended Decision issued on November 8, 2013, ALJ Barnes recommended that the Companies' Petition be adopted as modified and directed the Companies to file an amended Plan within 120 days of the Commission's Order.

Exceptions to the Recommended Decision were filed by the Companies and the OCA on December 2, 2013. Replies to Exceptions were filed by the Companies and the OCA on December 12, 2013.

In our *March 6 Order*, we adopted the Recommended Decision of ALJ Barnes, with modifications. In response to a request by FirstEnergy to accelerate the smart meter deployment schedule in the Penn Power system we directed that:

> ...if the Companies feel strongly about implementing this accelerated Penn Power deployment schedule, then they should promptly submit an amended Plan, with proper supporting documentation, with the Commission to properly provide the opportunity for all affected Parties, as well as this Commission, to fully evaluate and comprehend this proposal. If the Companies decide to pursue an accelerated deployment, they must file an amended Plan within thirty days of the entry of this Opinion and Order, stating their case more fully and in more detail. 52 Pa. Code § 5.93(a). Thereafter, the Commission will schedule an expedited procedural schedule so that the amended Plan could be decided within ninety days of the entry of the instant Opinion and Order.

March 6 Order at 43.

Subsequently, on March 19, 2014, the Companies submitted their Revised Deployment Plan, which was filed to serve both as a compliance filing with respect to the *March 6 Order* and as explanation and support for the modification of the Original Deployment Plan filed on December 31, 2012. On March 31, 2014, the OCA filed Exceptions in response to the Revised Deployment Plan filing pursuant to 52 Pa. Code § 5.592. The Companies filed a response to the OCA's Exceptions on April 7, 2014.

On April 16, 2014, the Commission issued a Secretarial Letter wherein the Companies' Revised Deployment Plan was referred to the Office of Administrative Law

Judge for the development of an evidentiary record on an expedited basis in order to permit consideration of this matter at the Public Meeting of June 5, 2014. The Secretarial Letter further directed the presiding officer to establish a procedural schedule that enabled the preparation of an order certifying the record to the Commission on or before May 15, 2014. Additionally, the Secretarial Letter directed the Bureau of Technical Utility Services to review and prepare a public meeting recommendation on the limited scope of compliance with the *March 6 Order*, but not the Revised Deployment Plan. We also considered compliance with the *March 6 Order* during our June 5, 2014, Public Meeting.

As a result, an evidentiary hearing was held on May 7, 2014, at which time the Companies' witnesses were presented for cross examination and the OCA witness was presented and cross-examined. A transcript of this evidentiary hearing was filed on May 8, 2012, consisting of pages 144 through 226.

Main Briefs were filed on May 14, 2012, by FirstEnergy, the Industrial Customer Groups and the OCA.

On May 15, 2014, ALJ Barnes issued an Order Certifying Record to the Commission identifying the documents that comprise the evidentiary record in this proceeding.

III. Discussion

A. Legal Standards

In this proceeding the Companies seek approval of their plan to accelerate the deployment of smart meters and, as such, have the burden of proving that the Petition complies with the applicable legal requirements. Act 129 allows an EDC to recover all

This original deployment schedule contemplated a three-year Solution Validation Stage wherein the Companies would first create a test lab in Penn Power's service territory by installing 60,000 meters before the end of 2016. FirstEnergy M.B. at 4.

According to FirstEnergy, during the period between the submission of briefs in June 2013, and the issuance of the ALJ's Recommended Decision in November 2013, it determined that it could prudently accelerate the smart meter deployment schedule. FirstEnergy states that the Revised Deployment Plan is based upon the most current available information and sets forth a plan that will accelerate the installation of smart meters, with all of Penn Power's 170,000 customers receiving smart meters by the end of 2015 and approximately 98.5 percent of all Pennsylvania FirstEnergy customers receiving smart meters no later than mid-2019. Therefore, deployment of 98.5 percent of all smart meters would be completed six months earlier under the Revised Deployment Plan as compared to the Original Deployment Plan. *Id.* at 4-5.

FirstEnergy explains that the total estimated nominal cost of the Revised Deployment Plan is the same as that included in the Original Deployment Plan, which includes the installation of 110,000 additional meters in Penn Power's service territory by the end of 2015, the completion of much of the smart meter and information technology (IT) infrastructure needed throughout the FirstEnergy Pennsylvania footprint during the shortened Solution Validation Period, and the acceleration of the commencement of the Full-Scale Deployment Phase by one year. However, the Companies will spend approximately $47 million more in capital during the period 2014 through 2019, with a significant portion of this amount occurring in the first three years of deployment and corresponding decreases occurring in later years.[4] As a result of accelerating this spend,

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[4] Met-Ed/Penelec/Penn Power/West Penn Statement No. 4-S (Fitzpatrick Supp.) at 5-6, OCA Statement No. 1-S (Hornby Supp.) at 16; Exh. GLF-3SR; Exh. GLF-4SR. Comparing the two plans, $51 million more capital will be spent through the Revised Deployment Plan in 2014; $49 million more in 2015; $40 million more in 2016; $7 million less in 2017; $28 million less in 2018; and $60 million less in 2019.

FirstEnergy notes that there will be cost shifts among the years, thus impacting both the overall net present value (NPV) of the Revised Deployment Plan and the surcharges to be imposed under Rider SMT-C.[5] According to FirstEnergy, these cost shifts, along with the estimated increase in realized operational cost savings of $12 million were reflected in the modeling of the Revised Deployment Plan. *Id.* at 6-7.

After reflecting the acceleration in spending and the anticipated acceleration of savings in the four cost savings categories identified by the Companies in the Original Deployment Plan, FirstEnergy asserts that the Revised Deployment Plan has a NPV that is $48.1 million more than the Original Deployment Plan when the Companies' Weighted Average Cost of Capital (WACC) is used as the discount rate and no other potential savings are taken into account.[6] However, the Companies explain that the Revised Deployment Plan is $8 million less than the Original Deployment Plan on an NPV basis when the customers' discount rate of 0.37 percent, which represents the average return an individual could earn on a one-year certificate of deposit (CD), is used.[7] Finally, the Companies note that by using a customer discount rate of 2.67 percent, which reflects the current yield on a ten-year U.S. Treasury note, the NPV of the cost of the Revised Deployment Plan is only $13 million more than the NPV of the Original Deployment Plan.[8] However, FirstEnergy asserts that this relatively minor cost differential is completely eliminated if the estimated savings from only one of the many potential benefits categories – the estimated savings from time of use rates offered by Electric Generation Suppliers (EGSs) – is factored into the analysis. FirstEnergy asserts that if this potential savings is factored into the analysis, the NPV of the Revised

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[5] Met-Ed/Penelec/Penn Power/West Penn Statement No. 4-S (Fitzpatrick Supp.) at 4.

[6] Met-Ed/Penelec/Penn Power/West Penn Statement No. 4-S (Fitzpatrick Supp.) at 6, 8.

[7] *Id.* at 6, 8 and 9.

[8] Met-Ed/Penelec/Penn Power/West Penn Statement No. 4-SR (Fitzpatrick Supp. Reb.) at 5, 7.

Deployment Plan is $630,000 less if the 2.67 percent interest rate is used as the discount factor, and $23 million less if the interest rate on the one year CD is used. *Id.* at 7-9.

FirstEnergy explains that the disparity between itself and the OCA regarding the Revised Deployment Plan is their differing views on the discount factor that should be assumed when assessing the two plans on a NPV basis. FirstEnergy asserts that the Revised Deployment Plan can be adopted at little or no additional cost to the customer, assuming the use of a reasonable discount factor that reflects the customer's opportunity cost for the money it otherwise would not spend during the first several years of the deployment schedule. FirstEnergy asserts that the OCA did not perform an independent NPV comparison of the two plans as it adopted all of the Company's assumptions except for one, the discount rate. FirstEnergy criticized the OCA's election to use a nine percent discount factor which was not income tax adjusted, was supposed to be used to assess federal government projects, and reflected a rate for the private sector. According to FirstEnergy, the nine percent discount rate simply does not reflect a residential customer's opportunity cost of the extra amount per month that the customer would pay during the first several years of deployment if the Revised Deployment Plan is implemented. *Id.* at 9-10.

b. Office of Consumer Advocate

The OCA contends that FirstEnergy's proposal to accelerate smart meter deployment will increase the costs of smart meters, as well as the associated rates to ratepayers, for a modest advancement in the actual deployment of smart meters. According to the OCA, the Companies have failed to show that the Revised Deployment Plan is reasonable or that it will provide benefits that justify its increased costs and rates. The OCA argues that the Companies' position, that the Revised Deployment Plan on a NPV basis will be less costly to ratepayers, is based on a fundamentally flawed analysis that uses a discount rate unsupported by economic theory or experience in other jurisdictions. The OCA opines that when an economically justified discount rate is used to analyze the Revised Deployment Plan, the result illustrates that the NPV costs, as well as the rates to ratepayers over the life of the plan, are significantly higher than under the Original Deployment Plan. OCA M.B. at 7.

The OCA submits that while the total amount of expenditures in nominal terms of the two plans may be the same, this comparison of nominal dollars does not measure the impact of the significant acceleration of capital investments under the Revised Deployment Plan relative to the Original Deployment Plan. The OCA states that to measure the impact on both ratepayers and shareholders, a NPV analysis must be conducted as this analysis accounts for the time value of money. While the Companies and the OCA agree as to the need for the NPV analysis, the OCA avers that it does not agree on the discount rate to be applied. According to the OCA, when the NPV analysis is conducted using the Companies' WACC, the Revised Deployment Plan would increase costs by $48.1 Million over the Original Deployment Plan. Furthermore, the OCA asserts that, while the costs to customers will increase on a NPV basis under the Companies' analysis, it is important to note that shareholders will have higher NPV earnings under the Revised Deployment Plan due to the $47 million increase in capital investment though the year 2019. *Id.* at 11-12.

Next, the OCA contends that the Companies' use of a 0.37 percent discount rate, which is based on the rate of a one-year CD, is improper for two reasons. First, the OCA claims that this rate is without foundation as the Companies admitted that they performed no analysis or customer surveys to arrive at this rate. Second, the OCA states that the Companies ignored the impact of the Revised Plan on ratepayers through 2019, when most of the accelerated spending and cost recovery will occur. According to the OCA, even if the 0.37 percent discount rate is used, the NPV cost to ratepayers through 2019 is 6.6 percent higher under the Revised Deployment Plan than under the Original Deployment Plan. *Id.* at 13-14.

The OCA then notes that the Companies, in Supplemental Rebuttal Testimony, recognized the issues with using the 0.37 percent discount rate and proposed using a 2.67 percent discount rate, which was based on the interest rate for the current ten-year U.S. Treasury note. While the OCA states that it does not agree with the use of the 2.67 percent discount rate, ratepayers would experience a significantly higher ($13 million) overall NPV cost for the Revised Deployment Plan based on this rate. As a result, the OCA opines that the Companies' analyses of the revised Deployment Plan do not support their position that ratepayers will be better off under the Revised Deployment Plan. According to the OCA, the Companies' analyses demonstrate that on a NPV basis, the Revised Deployment Plan will increase costs to ratepayers in both the short term and the long term. *Id.* at 14-15.

The OCA avers that based on its analysis of the Company's Revised Deployment Plan, it is proper to use the Companies' model and a discount rate of nine percent. The OCA maintains that a nine percent discount rate is consistent with the weighted average cost of capital of between 8.17 to 11.29 percent that the Companies used to prepare NPV analyses from their perspective. Further, the OCA asserts that the nine percent discount rate is within the range of discount rates used to analyze smart meter deployment plans across the country. The OCA referred to its Cross-Examination Exhibit 2, which provided the assumptions used in the discount rate calculations for the smart grid project cost-benefit analysis for eight other companies, including West Penn's original smart meter deployment plan at Docket No. M-2009-2123951, prior to its merger with the FirstEnergy Companies. The discount rates from the referenced OCA exhibit range from 6.69 per cent to 8.954 per cent.

The OCA submits that the discount rates used for these other companies show the reasonableness of its use of a nine percent discount rate. According to the OCA, when a nine percent discount rate is used, the NPV cost of the Revised Deployment Plan is twelve percent higher through 2019 than the Original Deployment

Plan, and the NPV net cost of the Revised Deployment Plan through 2032 is 7.6 percent higher. *Id.* at 16-18.

Lastly, the OCA states that the NPV analyses conducted in this proceeding quantifies the future costs and benefits of the Revised Deployment Plan and that these costs and benefits are inputs into the revenue requirements that are the basis of the rates charged to customers. The OCA notes that on a NPV basis, ratepayers would pay eighteen percent more in revenue requirements from 2013 to 2032 and forty-six percent more in revenue requirements from 2013 to 2019, while the Companies' shareholders will have higher NPV aggregate earnings under the Revised Deployment Plan. The OCA opines that the increased rates charged to ratepayers through the SMT-C riders for the rather minor level of accelerated smart meter deployment proposed by the Companies are not reasonable. The OCA points out that for residential customers, SMT-C rates will be higher by amounts ranging from $0.95 per month to $3.39 per month. However, according to the OCA, the Revised Deployment Plan will only accelerate the deployment of smart meters to all customers by six months to the middle of 2019 as compared to the end of 2019 under the Original Deployment Plan. As a result, the OCA's position is that the Commission should reject the Companies' Revised Deployment Plan and direct the Companies to proceed with the Original Deployment Plan as already approved by the Commission in the *March 6 Order*. *Id.* at 18-24.

c. Industrial Customer Groups

The Industrial Customer Groups state that the Companies' Revised Deployment Plan is just and reasonable, and as such should be approved by the Commission. The Industrial Customer Groups allege that the Revised Deployment Plan advances the goals of Act 129 by ensuring that customers will be charged based on their individual meter data at an earlier time than under the Companies' Original Deployment Plan. Additionally, the Industrial Customer Groups aver that an expedited deployment of smart meters will reduce the use of estimated meter data, which will, in turn, reduce a number of customer charges such as unaccounted-for-energy costs. The Industrial Customer Groups note that customers may reduce their costs further by altering their usage behavior after the expedited deployment of smart meters. According to the Industrial Customer Groups, as the Revised Deployment Plan is an improvement to the Companies' Original Deployment Plan, they recommend its adoption. Industrial Customer Groups M.B. at 3-6.

2. Disposition

Based upon our review of the evidence of record, we conclude that FirstEnergy has met its burden of proof to establish that its Revised Deployment Plan is reasonable and in the best interest of its customers. While the Parties provided disparate positions on the appropriate NPV analysis, we note that the use of a higher discount rate based on corporate costs of capital results in a higher cost for the Plan, since the benefits of the plan are discounted more heavily. On the other hand, the use of a lower discount rate, based on money market or U.S. Treasury bond returns, results in a lower cost for the Plan, since the long term benefits of smart meters are discounted less. While well intentioned Parties can all agree to disagree about appropriate discount rates, what is clear in this case, as provided by the Companies, is that only a fraction of the benefits of this revised Plan have been captured in this analysis.

First, this analysis does not factor in other non-operating cost savings that customers may receive sooner through the Revised Deployment Plan. The non-operating cost savings benefits are those that may benefit customers, but may not necessarily reduce an electric distribution company's operating costs. Examples of these types of potential sources of benefits are listed in an October 2013 report entitled "Smart Grid Economic and Environmental Benefits – A Review and Synthesis of Research on Smart Grid Benefits and Costs" ("Report"), prepared by the Smart Grid Consumer

Collaborative ("SGCC"), which studied fifteen utilities' smart meter/smart grid projects that were partially funded through the U.S. Smart Grid Investment Grant program funds. The Report lists as potential sources of non-operating cost savings the following: (1) Integrated Volt/Var Control; (2) Remote Meter Reading, which is incorporated into the Companies' savings analysis; (3) Time Varying Rates; (4) Prepayment and Remote Disconnect; (5) Revenue Assurance; (6) Customer Energy Management; (7) Service Outage Management; (8) Fault Location and Isolation; and (9) Renewable Generation Integration.

Similarly, the Industrial Customer Groups identified other non-operating cost savings by averring that an expedited deployment of smart meters will reduce the use of estimated meter data, which will, in turn, reduce a number of customer charges such as unaccounted-for-energy costs. The Industrial Customer Groups note that customers may reduce their costs further by altering their usage behavior after the expedited deployment of smart meters. Indeed, these were some of the benefits we identified in approving the recent rulemaking Amending Regulations Regarding Standards for Changing a Customer's Electricity Generation Supplier. *Rulemaking to Amend the Provisions of 52 Pa. Code, Chapter 57 Regulations Regarding Standards For Changing a Customer's Electricity Generation Supplier*, Docket No. L-2014-2409383 (Order entered April 3, 2014).

Second, not all potential operating cost savings for the Companies were included in this analysis. The Companies only quantified four cost savings categories that they believed were measureable, verifiable and would allow the Companies to realize actual cash savings through the deployment of smart meters: (1) Meter Reading; (2) Meter Services; (3) Back Office; and (4) Contact Center. Each of these savings categories can be measured through metrics known today. Other categories were also analyzed for inclusion, but were ultimately not selected because they could not meet the parameters described, according to the Companies.

The OCA suggested in its testimony that the Companies should have looked for potential cost savings in other areas including: (1) revenue protection; (2) improved cash flow; (3) avoided capital costs; and (4) future purchases of traditional meters. Each of these areas was reviewed by the Companies. However, the Companies asserted that valid estimates of realizable savings in these areas cannot be made at this time. While there may be potential savings in these or other areas, given the Companies' proposed meter deployment schedule, it may take years to determine if, in fact, the Companies will realize any savings in these areas and, if so, the amount of that savings. Until the meters are installed and data can be studied, it may be difficult to more accurately access these savings. That said, we find it compelling that, in addition to the savings clearly identified by the Companies in their plan, there is the potential for additional operating cost savings in a number of areas.

Third, this Commission has already observed the benefits of early deployment. We find that the use of Penn Power as a case study may help the Companies identify other more cost effective meter deployment strategies that can then be leveraged by FirstEnergy's other operating companies. If deployment and operational savings prove very positive, FirstEnergy may also be in a position to further accelerate smart meter deployment, thus enabling an option to enhance customer savings even more.

And finally, it should also be noted that Act 129 uses the language "not to exceed 15 years." An EDC is encouraged to expedite the deployment process if it will provide increased customer benefits in a cost-effective manner. Again, the primary goal of the EDC deployment plan should be to implement a deployment and installation schedule that best balances the overall efficiency and timeliness of the smart meter installations with the costs incurred. Given the clear advantages that accelerated smart meter deployment will provide to both the Companies and their customers, we shall approve FirstEnergy's Plan as submitted.

Accordingly, we shall direct FirstEnergy to implement its Revised Deployment Plan and not pursue their Original Deployment Plan.

IV. Conclusion

For the reasons set forth above, we shall approve the Revised Smart Meter Deployment Plan submitted by FirstEnergy, consistent with this Opinion and Order. FirstEnergy is directed to implement its Revised Deployment Plan, subject to any modifications contained in our companion Compliance Order adopted today at this docket; **THEREFORE,**

IT IS ORDERED:

1. That the Revised Smart Meter Deployment Plan submitted on March 19, 2014, by Metropolitan Edison Company, Pennsylvania Electric Company, Pennsylvania Power Company and West Penn Power Company is approved.

2. That Metropolitan Edison Company, Pennsylvania Electric Company, Pennsylvania Power Company and West Penn Power Company be required to fully investigate and track all sources of potential savings, including, but not limited to, theft reduction, revenue enhancement, avoided capital costs and distribution operations, and flow-through these savings to their customers in future SMT-C rider filings.

3. That the Smart Meter Deployment Plan as proposed by the Joint Petition of Metropolitan Edison Company, Pennsylvania Electric Company, Pennsylvania Power Company, and West Penn Power Company for Approval of their Smart Meter Deployment Plan filed on December 31, 2012, in the above-captioned matter is adopted as modified by this Opinion and Order and as may be modified by the companion Compliance Order adopted June 5, 2014, at this docket.

BY THE COMMISSION,

Rosemary Chiavetta
Secretary

(SEAL)

ORDER ADOPTED: June 5, 2014

ORDER ENTERED: June 25, 2014