BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

RULEMAKING RE ELECTRIC DISTRIBUTION COMPANIES' OBLIGATION TO SERVE RETAIL CUSTOMERS AT THE CONCLUSION OF THE TRANSITION PERIOD PURSUANT TO 66 Pa. C.S. § 2807(e)(2)	:	**DOCKET NO. L-00040169**
DEFAULT SERVICE AND RETAIL ELECTRIC MARKETS	:	**DOCKET NO. L-00070183**

COMMENTS OF PECO ENERGY COMPANY
TO THE ADVANCE NOTICE OF FINAL RULEMAKING ORDER
AND PROPOSED POLICY STATEMENT

I. INTRODUCTION

On February 9, 2007, the Pennsylvania Public Utility Commission (the "Commission") issued (1) an Advance Notice of Final Rulemaking Order (the "Rulemaking Order" or "Regulations") and (2) a Proposed Policy Statement (the "Policy Statement"), defining the obligations of electric distribution companies ("EDCs") and, where applicable, their successors to serve retail electric customers at the conclusion of the EDCs' transition periods. Interested parties were given until March 2, 2007 to file written comments.

PECO Energy Company ("PECO") has long been a vocal advocate of retail competition for electric generation and, accordingly, has actively participated in the Commission's default service provider ("DSP") rulemaking initiative since its beginning. In comments submitted in April, 2005, PECO noted that "the rules which emerge from this process will be critically important to the economic well-being of Pennsylvania and Pennsylvanians in the years to come." PECO appreciates the complexity of this task and, on balance, believes that the Commission has done a commendable job of developing a workable framework for the further evolution of competitive retail electric markets.

II. SUMMARY OF POSITION

At page 5 of its Rulemaking Order, the Commission observes that it "… is mindful of the risks of being too prescriptive in its approach to this rulemaking" and, for that reason, has not attempted "to dictate the exact manner by which every DSP will acquire electricity, adjust rates, and recover their costs." Likewise, in its Policy Statement, the Commission rejects the notion that one size fits all when it comes to default service and concludes that "each DSP should craft an approach best suited to its own service territory" (p. 4).

PECO agrees with the Commission that customers will be best served if DSPs are accorded flexibility in tailoring their default service strategies to their particular customer bases. PECO also believes that the Regulations, with limited exception, are true to that principle. For example, while the Regulations require that generation supply be obtained from competitive bid solicitations (i.e., auctions or RFPs), spot market energy purchases or a combination of both (§ 54.186(b)(4)), it is left to the DSP to fashion the procurement model that makes the most sense given its unique circumstances. Similarly, the Regulations do not tell DSPs what energy products they must buy or how they must price them. Rather, these details are properly left to individual utilities' implementation plans.

In contrast, however, the Policy Statement, after initially disavowing a "prescriptive" approach, proceeds to stake out positions on the "prudent mix" of generation supply, the appropriate grouping of customers for procurement and rate design purposes, and the various categories of costs that should be recovered through default service rates. Although these recommendations are characterized as "guidelines," PECO is concerned that they will be construed as something far more than that. Indeed, according to Section 69.1802 of the Policy

Statement, the Commission expects that the initial guidelines "... will be applied to the first set of default service plans following expiration of the generation rate caps, and that the guidelines will be reevaluated prior to the filing of subsequent default service plans."

It is well-understood that a policy statement is neither a rule nor a precedent, but simply an announcement to the public of an agency's tentative intentions for the future: "A general statement of policy ... does not establish a 'binding norm'.... When the agency applies the policy in a particular situation, it must be prepared to support the policy just as if the policy statement had never been issued." *See Home Builders Association of Chester and Delaware Counties v. Department of Environmental Protection*, 828 A.2d 446 (2003). By stating, however, that its initial guidelines "will be applied" to the first round of implementation plans and by warning that DSPs will have to present "compelling evidence" for taking an alternative approach (Policy Statement Order, p. 4), the Commission arguably creates "binding norms," at least for purposes of the initial implementation plans, and transforms policy guidance into what could reasonably be interpreted as rules that have the force of law.

PECO is convinced that it was not the Commission's intent to utilize the Policy Statement to develop "binding norms" or to impose the kind of "prescriptive" approach that it expressly rejects in its Rulemaking Order. Stated differently, PECO believes that the overriding purpose of the Policy Statement is to give DSPs the benefit of the Commission's current thinking on a host of issues and not to stifle their creativity or dampen their resolve to find reasonable answers for their default service customers. Unfortunately, as currently drafted, the Policy Statement leaves the impression that the Commission has already made up its mind on certain key issues that, in PECO's view, arguably should be further analyzed, addressed and decided on a case-by-case basis.

In the balance of these comments, PECO identifies areas where it believes the Regulations can be strengthened and/or clarified. For the most part, however, PECO is satisfied that the Regulations strike an appropriate balance and provide DSPs the flexibility they will require. For that reason, most of PECO's suggested changes are to the Policy Statement.[1]

III. SPECIFIC COMMENTS

A. Procurement

1. Mechanism - How to Buy

The proposed Regulations provide that "[a]ll electric generation supply should be acquired either through competitive bid solicitation processes, spot market energy purchases, or a combination of both" (§ 54.186(b)(4)). In addition, the Rulemaking Order leaves open the possibility of utilizing short-term bilateral contracts to satisfy emergency requirements (p. 15). On balance, this is a reasonable approach and permits DSPs to tailor their procurement strategies to their specific needs and those of their customers. Particularly significant is the Commission's conclusion that "the optimal method of acquiring electricity includes a direct exposure to market forces" (Rulemaking Order, p. 14). PECO wholeheartedly endorses that finding and firmly believes that meeting customers' needs for reliable, reasonably priced energy is best achieved by embracing competitive markets.

Joint Auctions. Consistent with its past comments, PECO continues to believe that there may be distinct advantages - - in terms of stimulating wholesale competition and reducing administrative costs - - to the coordination of procurement on a statewide basis. Although the Policy Statement notes that the Commission does not favor the model currently utilized in New Jersey (p. 4), the Regulations nonetheless allow DSPs to band together voluntarily and submit a

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[1] For the Commission's benefit, we have marked up the proposed Regulations and Policy Statement with changes that reflect our comments (*see* Appendices A and B, respectively).

"multi-service territory procurement and implementation plan" (§ 54.185(e)). PECO intends to work with other DSPs to develop a joint procurement model that is acceptable to the Commission.[2]

Spot Purchases. In addition, PECO proposes that the definition of "spot market energy purchase," as set forth in Section 54.182 of the Regulations, be clarified and expanded to include the procurement of "spot market-based service" components through a competitive solicitation process and not solely through a "FERC-approved real time or day ahead energy market." Spot market-based service can be obtained and billed directly from PJM by arranging for PJM to meet load serving entity obligations, with the DSP as a price taker for energy, capacity, ancillary services and transmission service. Alternatively, auctions and/or RFPs for full-requirements "spot market-based service" can be structured in such a way that the energy component is indexed to either a day-ahead or real-time PJM spot energy price and the associated non-spot energy components (e.g., capacity, ancillary services, transmission) are based on the lowest bid. Either alternative - - direct purchase from PJM or indexed spot price competitively procured product - - should satisfy the Commission's desire that the supply portfolio contain a "seasonal" element.

2. Product - What to Buy

The Regulations require that a DSP's procurement plan be designed to acquire "electric generation supply at prevailing market prices to meet the DSP's anticipated default service

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[2] PECO continues to support, and presently plans to propose, a declining block auction for full-requirements, load-following products. In this regard, we note that PECO's sister company, Commonwealth Edison, recently completed a successful auction for default service in Illinois. PECO may also seek to commence procurement of post-rate cap default service in the next year or so with the goal of assembling a portfolio of laddered contract terms to mitigate the risk of significant increases in retail rates on January 1, 2011.

obligation *at the lowest reasonable long-term costs*" (§ 54.186(b)(l) (emphasis added). Other than authorizing the use of "solicitations and contracts whose duration extends beyond the program period" (§ 54.186(b)(3)), the Regulations themselves do not dictate the products a DSP must procure to satisfy this standard. Unfortunately, the Policy Statement seriously calls into question the amount of discretion that will actually be accorded DSPs. It does so by (1) introducing the notion of a "prudent mix" of various demand and supply-side resources, (2) delineating certain "customer groupings," and (3) suggesting specific supply contract durations for each of those groupings.

"Reasonable Cost" Standard. As a threshold matter, PECO submits that the phrase "at the lowest reasonable long-term costs" should be deleted from Section 54.186(b)(1) for two reasons. First, this standard is inconsistent with, and arguably goes far beyond, Section 2807 of the Electric Competition Act, which requires DSPs to "acquire electric energy at prevailing market prices" and authorizes them to "recover fully all reasonable costs" (66 Pa. C.S. § 2807(e)(3)). Second, use of the term "lowest reasonable long-term costs" will simply invite debate and potential litigation. For example, others may argue that the inclusion of certain demand-side and alternative energy resources may, in fact, increase costs and therefore will not satisfy the standard. In addition, in its Policy Statement Order (p. 5), the Commission declines to indicate what it means by "long-term," suggesting that "long-term" is "not readily subject to definition."

Procurement Guidelines. Apart from this initial concern, PECO believes that the Policy Statement, in setting forth procurement guidelines, is too vague in some respects and, if strictly applied, too "prescriptive" in others. Thus, Section 69.1805 advises DSPs, in procuring generation, to "balance the goals of allowing the development of a competitive retail supply market and also including a prudent mix of arrangements to minimize the risk of over-reliance on any particular source." However, the Policy Statement provides no guidance as to how such a balance might be struck or, for that matter, why the statute requires such balancing in the first instance. In any event, PECO firmly believes that the competitive market does the best job of allocating resources and ensuring reliable supplies at reasonable cost. For that reason, and as noted previously, PECO intends to pursue procurement through full-requirements, load-following products, with staggered contract terms to mitigate price volatility.

Section 69.1805 then identifies various resources to be considered in assembling a "prudent mix" - - "supply-side and demand-side resources such as long-term, short-term, staggered-term and spot market purchases." PECO already has a robust demand-side program and will continue to promote and expand that service. In addition, PECO will certainly consider all of its supply-side options. However, the "prudence" of a particular supply mix will vary over time depending upon market conditions and a utility's specific circumstances. For that reason, PECO questions the value of the three procurement strategies outlined at Section 69.1805. Simply stated, there is no evidentiary or other basis for concluding, at this point, that a "prudent mix" for residential customers must include a "spot" component or that customers with peak loads ranging from 25 kW to 500 kW would best be served by fixed-term contracts not exceeding one year in duration. To avoid confusion or misinterpretation, PECO recommends that either these examples be deleted or it made clear that they are presented for illustrative purposes only.

Another area that could benefit from clarification concerns the use of long-term contracts in procuring default service supplies. As noted previously, the Regulations allow DSPs to propose "solicitations and contracts whose duration extends beyond the program period" (§

54.186(b)(3)). The Policy Statement, on the other hand, provides that long-term contracts "should only be used where necessary and required for DSP compliance with alternative energy requirements and should be restricted to covering a relatively small portion of the default service load" (§ 69.1805). In addition, Section 69.1805 seems to favor contract durations of no more than three years for residential and small commercial customers and no more than one year for customers with peak loads ranging from 25 kW to 500 kW.

PECO presumes that the Commission wishes to avoid situations where a disproportionate percentage of a DSP's future generation supply is tied up in contracts of extended duration and to thereby mitigate the extent to which the PTC deviates substantially from short-term wholesale prices. That, however, is no reason to impose artificial constraints on a DSP's procurement activities by limiting non-AEPS supply contracts to three years or less (as the Policy Statement appears to do). Rather, PECO believes that DSPs should be given the discretion to enter into contracts of somewhat longer duration, subject to the Commission's review of the reasonableness of the composite generation supply package.

3. Timing and Frequency - When to Buy and How Often

The Regulations do not tell DSPs when or how frequently they must enter the market to buy power. However, both the Rulemaking Order (p. 4) and the Policy Statement Order (p. 4) recommend that DSPs use multiple procurements over the course of a year. The Policy Statement itself goes even further, suggesting "a minimum of two competitive bid solicitations a year" for customers with peak demands of 500 kW or less (§ 69.1805(a) and (b)).

PECO concurs that it is advisable to reduce the DSPs' exposure to filling significant requirements at times of abnormally high prices and agrees that it may be necessary to utilize multiple procurements to put together an initial default service supply procurement plan.

However, once an acceptable portfolio of different length and/or laddered contract terms has been assembled, the ongoing benefits of semi-annual procurements must be weighed against their costs.

Moreover, multiple procurements and quarterly (or more frequent) rate adjustments (§ 54.187(h) and (i)) are unlikely to send consumers meaningful price signals unless a DSP is willing to commit a substantial portion of its default service supply to spot market purchases. While this may be a reasonable strategy for larger, more sophisticated customers with the expertise to manage their consumption through the use of financial or physical products, PECO questions the wisdom of such an approach for smaller ones, particularly residential and small commercial customers, who generally prefer price stability and who depend on their DSP to mitigate their exposure to wide price swings. PECO gleans from the Regulations (§ 54.187(h) and (i)) that the quarterly rate adjustment mechanism is being proposed to not only "ensure the recovery of costs," but also "to reflect the seasonal cost of electricity." However, the goal of more seasonal retail pricing can be met for residential and small commercial customers by soliciting bids for a seasonally priced load-following product that may include a modest (i.e., up to 5%) spot market-based service component (e.g., basis-adjusted index price). In other words, semi-annual procurements and frequent spot market purchases are not needed in the case of smaller customers to achieve the Commission's objectives. Accordingly, PECO proposes that the Regulations be revised to permit DSPs to adjust and reconcile their rates for residential and commercial customers once a year.[3]

[3] This is not to imply that DSPs would necessarily procure all of their default service requirements for residential and commercial customers through a single annual auction or RFP. Rather, it is more likely that a staggered approach would be adopted such that only a portion of the total supply portfolio would be bid out on an annual basis.

B. Pricing

1. Rate Design - - "Single Rate Option," Declining Block Rates and Demand Charges

The Regulations require that each default service customer be offered a "single rate option" to be identified as the Price to Compare, or "PTC" (§ 54.187(b)).[4] The Regulations also provide that the default service rate schedule - - presumably the PTC - - should be priced "based on the average cost to acquire supply for each customer class" (§ 54.187(a)). Finally, the Regulations prohibit the use of rates that decline with increased usage (§ 54.187(c)) and the Policy Statement encourages the elimination of demand charges (§ 69.1810).

PECO foresees several problems with these proposals. First, the Regulations would appear to bar offering a default service customer more than one rate, i.e. the "single rate option." Thus, if strictly construed, PECO might have to discontinue its wind tariff offering, which, to date, has attracted over 30,000 customers. Similarly, if a DSP were to propose a fixed-price option for its largest customers, hourly pricing arguably could not also be made available to such customers.[5] PECO doubts that this is what the Commission had in mind and, consequently, asks for clarification.

PECO is similarly troubled by the directive that the same "single price option" be offered to all customers within the same customer class, particularly if DSPs are to be denied the ability to utilize load factor-based declining block rate structures and/or demand charges. Rate classes,

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4 The Regulations purport to carve out an exception for the use of an automatic energy adjustment clause to recover non-alternative energy default service costs (§ 54.187(f)). It is unclear, however, whether the automatic adjustment clause mechanism is in lieu of the PTC or in addition to it.

5 The Policy Statement provides that DSPs "may propose a fixed-price option [for large customers] for the Commission's consideration," but does not mandate that they do so (§ 69.1805(3)).

no matter how carefully drawn, invariably include customers with markedly different usage characteristics. For example, some industrial customers are able to maintain extremely high load factors, while others are not. Those different consumption patterns, in turn, impose very different costs on an electric utility.[6] Consequently, the single rate option, coupled with the elimination of load factor-based declining block rates and/or demand charges, would produce rates that bear little semblance to the true cost of service and would therefore run counter to the Commission's goal of promoting energy efficiency and demand response.

PECO's existing rates were specifically designed to reflect the different costs of serving different kinds of customers and thereby promote conservation and wise energy use by sending appropriate price signals. Thus, PECO's commercial and industrial rates include demand charges and/or load factor-based declining energy blocks. In addition, PECO's residential rates include declining blocks for heating load and off-peak discounts for certain large appliance usage.[7]

Because demand charges and load factor-based declining block rates are a vital component of PECO's existing rate design, and because, in many instances, customers have made important operational or purchasing decisions based on those rate design features, it necessarily follows that their elimination will have a disruptive effect on individual customers' bills. Moreover, as a general matter, such changes would invariably benefit less efficient low load factor customers and penalize more efficient high load factor customers, an anomoly that runs counter to the objective of promoting increased demand-side response. In Appendix C to

[6] As discussed *infra*, some categories of costs (e.g., capacity, transmission, and certain ancillary service costs) can vary significantly depending on the timing and demand for the related services.

[7] PECO currently has approximately 150,000 residential heating customers (Rate RH) and 86,000 off-peak service customers (Rate OP).

these comments, we have illustrated what we believe would be the unintended consequences of converting to a flat, cents-per-kWh rate structure. The first example portrays two commercial customers with comparable 25 kW peak demands, but substantially different usage patterns. Here, the low load factor customer experiences a 16% **decrease** in its total bill, while the high load factor customer sees its bill **rise** by 15%. The second example, depicting two industrial customers with peak loads of 1 MW, shows similar disparate results - - the poor load factor customer's bill drops by 37%, while the good load factor customer incurs a 6% increase.[8]

PECO does not object to the procurement of default service on a customer class basis. However, it is imperative that DSPs be permitted to design rates that not only recover the supply costs incurred on behalf of a particular customer class, but also capture daily and seasonal differences in the usage characteristics of individual customers within the class. Demand charges and load factor-based declining block rates, if properly structured, can serve that important function. In any event, the examples provided in Appendix C demonstrate that the type of rate design changes contemplated by the Regulations and the Policy Statement require substantial further analysis, after notice to customers, to determine and evaluate, on a case-by-case basis, their probable impact.

For all of these reasons, PECO urges the Commission to refrain from establishing hard-and-fast rules dictating how DSPs must price default service. Rate design, by its very nature, is an exceedingly complex matter and, in PECO's view, DSPs should be provided more tools with which to work, not have them taken away. In any event, this issue should be taken up when the Commission reviews individual DSP implementation plans.

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8 For purposes of the foregoing examples, we assumed no change in total class cost recovery levels and simply quantified the effect of abandoning PECO's current commercial and industrial rate designs.

2. Cost Allocation

Section 54.187(d) of the Regulations provides that the PTC shall be designed to recover "all generation, transmission, and other default service cost elements …" The Policy Statement, in turn, enumerates various "cost elements" that arguably fall within those categories (§ 69.1808(a)) and further requires that any generation-related costs "embedded in distribution rates" be stripped out of distribution charges "after the expiration of Commission approved rate caps" (§ 69.1808(b)).

The identification and quantification of specific costs properly recovered through a PTC are clearly beyond the scope of this proceeding and should await the filing of individual DSP implementation plans. That having been said, PECO offers three observations for the Commission's consideration. First, the Policy Statement proposes that the PTC include all "[w]holesale energy, capacity, ancillary, congestion, applicable RTO or ISO administrative, and transmission costs" (§ 69.1808(a)(1)). Notably, certain of these cost elements (e.g., capacity, transmission, and certain ancillary service costs) are priced out on the basis of the timing and demand for such services, thus lending further support for the retention of demand charges in designing default service rates.

Second, PECO assumes, and asks the Commission to confirm, that any generation costs found to be "embedded" in distribution rates are to be removed upon the expiration of the DSPs' **generation** rate caps.[9] If that is the Commission's intent, no purpose would be served in taking this issue up in an interim distribution rate case or launching a special "cost allocation case" prior to the submission of a DSP's default service implementation plan.

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[9] Otherwise, legitimate costs would be "trapped," i.e. no longer included in distribution rates but not yet recoverable through generation rates.

Lastly, the Policy Statement indicates that "[a]ll costs for alternative energy portfolio standard compliance" are to be recovered through the PTC (§ 69.1808(a)(5)). At the same time, and consistent with the terms of the Alternative Energy Portfolio Standards Act, 73 P.S. § 1648.1 *et seq*., the Regulations require that DSPs utilize Section 1307 automatic energy adjustment clauses to recover AEPS costs (§ 54.187(e)). Read together, these provisions suggest that the PTC itself should be structured as an automatic adjustment clause. While PECO has no objection to the use of a single automatic adjustment clause to recover both AEPS compliance costs and non-alternative energy costs, Sections 54.187(b), (e) and (f) of the Regulations seem to anticipate, or at least allow, separate pricing mechanisms. PECO requests that the interplay of these provisions be clarified.

C. Cost Recovery

Depending upon the customer class, the Regulations provide for the quarterly, monthly or even more frequent updating of default service rates to "reflect the seasonal cost of electricity " (§ 54.187(h), (i) and (j)). The Regulations specifically allow DSPs to use a Section 1307 mechanism to change the PTC, while the Policy Statement encourages reconciliation as part of the PTC adjustment process and suggests that default service rates could be reconciled even more often under certain circumstances (§ 69.1809). The updating of rates and reconciliation of cost recovery presumably would be accomplished through the implementation of a Section 1307 automatic adjustment mechanism under Section 54.187(f) and/or (g) of the Regulations.

PECO fully supports the Section 1307 option and believes that, if properly structured (*see* discussion, *infra*), its use will enable DSPs to "fully recover all reasonable costs," as required by Section 2807(e)(3) of the Electric Competition Act (66 Pa. C.S. § 2807(e)(3)). At the same time, PECO questions whether quarterly updating and reconciliation (as opposed to annual rate adjustments) should be mandated for smaller customers. As discussed previously, it is unlikely that DSPs will include a substantial spot market component in the bundle of supplies procured on behalf of residential customers and, accordingly, the rate charged such customers should not require dramatic adjustments from quarter to quarter. Rather than sending meaningful price signals, such frequent but insignificant rate changes could lead to customer confusion and the incurrence of unnecessary administrative cost. At the same time, however, periodic rate adjustments may be appropriate to capture substantial and unanticipated fluctuations in generation prices and/or variations in projected demand. Accordingly, DSPs should be afforded the discretion to adjust prices and reconcile cost recovery on a quarterly basis for smaller customers, but should not be required to do so.

PECO further notes that reconciliation alone, regardless of its frequency, will not assure DSPs the "full recovery of all reasonable costs" to which they are entitled unless (1) carrying charges accrue on over and undercollections and (2) safeguards are built into the system to protect DSPs against "migration risk." With respect to the former, PECO recommends that the legal rate of interest (6.0%) be utilized and that the Regulations be revised to so specify. As to "migration risk," the Regulations should make clear that a customer may not evade reimbursement of its DSP for prior undercollections by switching its service to an alternative generation supplier. Similarly, if customers choose to participate in a voluntary phase-in program upon the expiration of a DSP's generation rate caps (*see* § 69.1811 of the Policy Statement), they should be obligated to pay all deferred balances and reasonable carrying charges irrespective of from whom they purchase generation in the post phase-in period. Appropriate changes to the Regulations and the Policy Statement have been reflected in Appendices A and B.

D. Switching Rules

PECO believes that the Regulations should be amended to allow DSPs to propose reasonable switching rules as part of their default service implementation plans. If customers are to be offered an annualized fixed-price option, there must be some mechanism in place to protect against "seasonal gaming."[10] To date, PECO has relied upon demand ratchets to discourage such activity, but, as noted earlier, the Policy Statement encourages the elimination of all demand charges. Experience in other states has shown that the absence of reasonable switching rules will compel wholesale suppliers to build substantial switching risk premiums into their competitive bids, thereby increasing the PTC for all members of the class. PECO therefore proposes that Section 54.189 of the Regulations be revised to authorize DSPs to require annualized fixed-price service customers to remain on that service for at least twelve months or, alternatively, to pay an exit fee for switching early.

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[10] "Seasonal gaming" refers to the practice of taking annualized fixed price DSP service during the high cost summer period and switching to monthly, daily or hourly service offered by an alternative generation supplier during the lower cost non-summer months.

IV. CONCLUSION

The default service rulemaking process has been a challenging one, as the Commission and interested stakeholders have strived to balance the need for "regulatory certainty" (Rulemaking Order, p. 6) with the practical realization that "[r]equirements that might seem very appropriate today could be rendered obsolete by changes in markets, applicable law, or advances in technology" (Policy Statement Order, p. 2). With the following revisions and clarifications, PECO believes that the Regulations and Policy Statement can serve that intended purpose:

- Clarify and expand the definition of spot market energy purchase at Section 54.182 of the Regulations and 69.1803 of the Policy Statement to include "spot" components procured through a competitive process.

- Delete the phrase "at the lowest reasonable long-term costs" from Section 54.186(b)(l) of the Regulations.

- Either delete the discussion of the three customer groupings/procurement strategies from Section 69.1805 of the Policy Statement or add language making clear that those examples are presented for illustrative purposes only.

- Allow annual procurements for smaller customers by deleting the discussion of the three customer groupings/procurement strategies from Section 69.1805 of the Policy Statement.

- Allow DSPs the option to retain load factor-based declining block rate structures and demand charges by modifying sections 54.187(c) of the Regulation and section 69.1810 of the Policy Statement.

- Defer examination of generation costs purportedly "embedded" in distribution rates until review of the DSPs' default service implementation plans by modifying section 69.1808(a) of the Policy Statement.

- Clarify that DSPs may use a single automatic adjustment clause to recover both AEPS compliance costs and non-alternative energy costs.

- Make quarterly (or more frequent) price updating and/or cost reconciliation for smaller customers an option, not a requirement by modifying sections 54.187(h) and (i) of the Regulation and section 69.1809(a) of the Policy Statement.

- Explicitly provide for the recovery of carrying charges on undercollections at the legal rate of interest by modifying sections 54.187(l) of the Regulation.

- Permit DSPs to collect prior period undercollections and deferred phase-in balances, with carrying charges, from "migrating" customers by modifying sections 54.187(l) of the Regulation.

- Provide DSPs the discretion to propose reasonable switching rules for certain retail rate structures by modifying sections 54.189(d) of the Regulation.

PECO applauds the Commission's efforts to address these important issues in a proactive way and appreciates the opportunity to participate in this critical dialogue. We look forward to continuing to work with the Commission and other stakeholders as this matter moves forward.

Respectfully submitted,

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ANNEX A

TITLE 52. PUBLIC UTILITIES

PART I. PUBLIC UTILITY COMMISSION

Subpart C. FIXED SERVICE UTILITIES

CHAPTER 69. GENERAL ORDERS,

POLICY STATEMENTS AND GUIDELINES ON FIXED UTILITIES

DEFAULT SERVICE AND RETAIL ELECTRIC MARKETS

§ 69.1801. Statement of scope.

This policy statement provides guidelines to default service providers regarding the acquisition of electric generation supply, the recovery of associated costs and the integration of default service with competitive retail electric markets.

§ 69.1802. Statement of purpose.

(a) The Commission has adopted regulations governing the default service obligation at 52 Pa. Code §§ 54.181-189, as required by Section 2807(e) of the Public Utility Code. These regulations address the elements of a default service regulatory framework. The goal of default service regulations is to bring competitive market discipline to historically regulated markets. This can be accomplished by structuring default service in a way that encourages the entry of new retail and wholesale suppliers. Greater diversity of suppliers will benefit ratepayers and the Commonwealth. However, these rules are not designed to resolve every possible issue relating to the acquisition of electric generation supply, the recovery of reasonable costs, the conditions of service, and the relationship with the competitive retail market.

(b) The Commission is very cognizant of the practical limits of regulating large, complex markets. Changes in federal or state law, improvements in technology, and developments in wholesale energy markets may render obsolete any all-inclusive regulatory approach to Pennsylvania's retail electric market.

(c) The Commission has devised an approach that will allow Pennsylvania to adapt to changes in energy markets and the regulatory environment. The regulations codified at Chapter 54 will serve as a general framework for default service and provide an appropriate measure of regulatory certainty for ratepayers and market participants. This policy statement will provide guidelines on those matters where a degree of flexibility is required to respond effectively to regulatory and market challenges. The Commission anticipates that the initial guidelines will be applied to the first set of default service plans following expiration of the generation rate caps, and that the guidelines will be reevaluated prior to the filing of subsequent default service plans.

§ 69.1803. Definitions.

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

Alternative energy portfolio standards – A requirement that a certain percentage of electric energy sold to retail customers in the Commonwealth of Pennsylvania by EDCs and EGSs be derived from alternative energy sources, as defined in the Alternative Energy Portfolio Standards Act, 73 P.S. § 1648.1, *et seq.*

Competitive bid solicitation process – A fair, transparent, and non-discriminatory process by which a DSP awards contracts for electric generation supply to qualified suppliers who submit the lowest bids.

Default service –

(i) Electric generation supply service provided by a DSP to a retail electric customer who is not receiving generation service from an EGS.

(ii) Electric generation supply service provided pursuant to a Commission approved default service plan.

Default service implementation plan – The schedule of competitive bid solicitations and spot market purchases, all technical requirements, and all related forms and agreements.

Default service procurement plan – The electric generation supply acquisition strategy the DSP will utilize in satisfying its default service obligations, including the manner of compliance with the alternative energy portfolio standards requirement.

Default service program – A filing submitted to the Commission by the DSP that identifies a procurement plan, an implementation plan, a rate design to recover all reasonable costs, and all other elements identified at 52 Pa. Code § 54.185.

DSP – Default service provider – The incumbent EDC within a certificated service territory or a Commission approved alternative default service provider.

EDC – Electric distribution company – This term shall have the same meaning as defined in 66 Pa.C.S. § 2803.

EGS – Electric generation supplier – This term shall have the same meaning as defined in 66 Pa.C.S. § 2803.

Maximum registered peak load – The highest level of demand for a particular customer, based on the PJM Interconnection, LLC, peak load contribution standard, or its equivalent, and as may be further defined by the EDC tariff in a particular service territory.

Prevailing market prices – Prices that are available in the wholesale market at particular points in time for electric generation supply.

PTC – Price-to-compare – The rate charged to a retail electric customer by the DSP for default service.

Retail customer or retail electric customer – These terms shall have the same meaning as defined in 66 Pa.C.S. § 2803.

RTO – Regional transmission organization – A FERC-approved regional transmission organization.

Spot market energy purchase – The purchase of an electric generation supply product[-either directly from an RTO or via a competitive procurement process, where the energy component of the purchase reflects the hourly pricing] in a FERC-approved real time or day ahead energy market.

§ 69.1804. Default service program terms and filing schedules.

The default service regulations provide for a standard initial program term of 2 to 3 years. Initial programs may vary from this standard to comply with the applicable regional transmission organization planning year. Subsequent programs should be for 2 years, unless otherwise directed by the Commission. The Commission will monitor developments in wholesale or retail markets and revisit this issue as appropriate. The Commission may revise the duration of the standard program term and program filing schedules based on market developments.

§ 69.1805. Electric generation supply procurement.

~~A proposed procurement plan should balance the goals of allowing the development of a competitive retail supply market and also including a prudent mix of arrangements to minimize the risk of over-reliance on any particular source.~~ In developing a proposed procurement plan, a DSP ~~should~~ [may] consider including a ~~prudent~~ mix of supply-side and demand-side resources such as long-term, short-term, staggered-term and spot market purchases to minimize the risk of contracting for supply at times of peak prices. ~~Long-term contracts should only be used where necessary and required for DSP compliance with alternative energy requirements, and should be restricted to covering a relatively small portion of the default service load.~~ An over reliance on long-term contracts would mute demand response, create the potential for future default service customers to bear future above market costs, and limit operational flexibility for DSP's to manage their default service supply. The plan [may utilize the] ~~should be tailored to the~~] following [illustrative] customer groupings [as may be appropriate], ~~but DSPs may propose alternative divisions of customers by registered peak load~~ to preserve existing customer classes [or avoid substantial rate impacts.]~~.~~

(1) *Residential customers and non-residential customers with less than 25 kW in maximum registered peak load*~~. Initially, the DSP should acquire electric generation supply for these customers using a mix of resources as described in the introductory paragraph to this section. Consideration should be given to procuring most fixed-term supply through full requirements contracts of one to 3 years in duration. Contracts should be laddered to minimize risk, with a minimum of two competitive bid solicitations a year to further reduce the risk of acquisition at a time of peak prices. In subsequent programs, the percentage of supply acquired through shorter duration full requirements contracts and spot market purchases should be gradually increased, depending on developments in retail and wholesale energy markets.~~

(2) *Non-residential customers with 25-500 kW in maximum registered peak load.* ~~The DSP should acquire electric generation supply for these customers using a mix of resources as described in the introductory paragraph to this section. Fixed-term contracts should be 1 year in length and may be laddered to~~

~~minimize risk, with a minimum of two competitive bid solicitations a year to further reduce the risk of acquisition at a time of peak prices. In subsequent programs, the percentage of supply acquired through shorter duration purchases and spot market purchases should gradually be increased, depending on developments in retail and wholesale energy markets.~~

(3) *Non-residential customers with greater than 500 kW in maximum registered peak load.* ~~Hourly priced or monthly-priced service should be available to these customers. The DSP may propose a fixed-price option for the Commission's consideration.~~

§ 69.1806. Alternative energy portfolio standard compliance.

In procuring electric generation supply for default service customers, the DSP must comply with the Alternative Energy Portfolio Standards Act of 2004, 73 P.S. §§ 1648.1, *et seq*. The Commission's default service regulations [shall be construed to] neither prohibit nor mandate the use of long term contracts to satisfy the alternative energy portfolio standards obligation. In satisfying this obligation, a DSP's procurement strategy should reflect the incurrence of reasonable costs.

§ 69.1807. Competitive bid solicitation processes.

The following guidelines will apply to competitive bid solicitation processes:

(1) DSPs should use standardized request for proposal documents and supplier master agreements approved by the Commission for use in the default service procurements. The Commission will review these documents and agreements on a regular basis and revise them when appropriate after consultation with stakeholders.

(2) The public interest would be served by the adoption of uniform criteria and processes for bidder qualification.

(3) Competitive bid solicitations should be structured along customer classes, consistent with the groupings identified in § 69.1804. Bids should be solicited for tranches of load within each customer class. Slice of system bid designs should not be utilized.

(4) The Commission finds that a clearly optimal bid solicitation model does not exist at the current stage of wholesale market development. DSPs may utilize various competitive bid solicitation approaches, including request for proposals that result in the submission of sealed bids and real time auctions in which energy suppliers compete with each other for tranches of customer load.

(5) DSPs are encouraged to coordinate their competitive bidding solicitation schedules to minimize conflicts that might negatively affect the ability of suppliers to participate in multiple procurements. DSPs with loads of greater than 50 megawatts should avoid scheduling pre-bid conferences, auctions, and the like, on the same day as other DSPs with loads greater than 50 megawatts.

(6) The Commission's objective is to review the results of competitive bidding processes in a manner sensitive to market dynamics but that also allows it to discharge its statutory obligations. The Commission recognizes that bid prices may be negatively affected by the length of time taken for Commission review. In the default service regulations, the Commission has reserved a period of 1 business day to review the results of competitive procurements. As retail and wholesale markets mature, and as other appropriate safeguards become available, the Commission may elect to reduce the amount of time it uses to review bidding results.

(7) The public interest would be served by the adoption of uniform rules for the confidentiality of competitive solicitation information. Supplier participation, bid prices, and retail rates may be impacted by protecting certain information,

including, the identity of winning and losing bidders, the number of bids submitted, bid prices, the allocation of load among winning bidders, and the like. At the same time, the Commission recognizes that there is a legitimate public interest in knowing some of this information when there is no possibility of any prejudice to ratepayer interests.

(8) The competitive bid solicitation process will be monitored by an independent evaluator. The Commission may direct that this evaluator administer competitive bid solicitations in order to ensure the independence of the process. This independent party will be selected by the DSP in consultation with the Commission. The DSP may not have an ownership interest in the evaluator, and vice versa, and the DSP should disclose any potential conflicts of interest on the part of the evaluator during this consultation process. The Commission will review conflicts of interest and may disqualify an evaluator in order to ensure the independence of the position. The evaluator should have an expertise in the analysis of wholesale energy markets, including methods of energy procurement. The evaluator should monitor compliance with Commission orders relating to a default service program, confidentiality agreements, and other directives. The evaluator should report all information it obtains to the Commission.

§ 69.1808. Default service cost elements.

(a) The PTC should be designed to recover all generation, transmission related and other related costs of default service, [including, but not limited to ~~. These cost elements include~~ the following cost elements to the extent they are incremental and avoidable when a customer switches to another supplier. Costs that are not incremental but are related to provision of default service, maybe billed as a separate non-bypassable DSP charge:]~~:~~

(1) Wholesale energy, capacity, ancillary, congestion, applicable RTO or ISO administrative, and transmission costs.

(2) Supply management costs, including supply bidding, contracting, hedging, risk management costs, any scheduling and forecasting services provided exclusively for default service by the EDC, and applicable administrative and general expenses related to these activities.

(3) Administrative costs, including billing, collection, education, regulatory, litigation, tariff filings, working capital, information system and associated administrative and general expenses related to default service.

(4) Applicable taxes, excluding sales tax.

(5) All costs for alternative energy portfolio standard compliance.

(b) EDC rates should be scrutinized for any generation related costs that remain embedded in distribution rates. This review should occur no later than the next distribution rate case for each EDC filed after the effective date of this policy statement. ~~The Commission may initiate a cost allocation case for an EDC on its own motion if such a case is not initiated by December 31, 2007~~ [If an EDC has not filed a rate case by 12/31/2007 it shall specifically address the issue of cost allocation in its Default Service Program filing.] Changes to rates resulting from such examination [of the cost allocation issue] would take effect after the expiration of Commission approved [generation] rate caps.

§ 69.1809. Interim price adjustments and cost reconciliation.

(a) Consistent with the default service regulations, the PTC will be adjusted, [at a minimum, on an annual] ~~on a regular~~ basis to reflect changes in and ensure the recovery of reasonable costs resulting from changes in wholesale energy prices or other costs. ~~For~~

~~example,~~ [A DSP may request more frequent PTC changes where tthe DSPs accumulated over/under recovery of purchased electric costs exceed 5 percent of its total anticipated costs for that annual period or for other reasons]~~he PTC will be adjusted at least every quarter for residential customers and as frequently as every month for large business customers~~. This PTC adjustment may be driven by changes in spot market prices, the use of laddered contracts, the use of seasonal rate design, and the like.

(b) The public interest may be served if default service costs and the revenues received through default service rates are reconciled as part of the PTC adjustment process. Reconciliation would ensure that DSPs fully recover their actual, incurred costs without requiring customers to pay more than is required. The PTC adjustment will therefore also reflect changes required due to the reconciliation of costs and revenues. Reconciliation proposals should result in a PTC adjustment that will resolve cumulative under or over collections by the time of the next PTC adjustment interval.

(c) It may be in the public interest to reconcile default service costs more frequently than at each PTC adjustment interval. The DSP should propose interim reconciliation prior to the next subsequent PTC adjustment interval when current monthly revenues have diverged from current monthly costs, plus any cumulative over/under recoveries, by greater than 5% since the last rate adjustment. When the divergence is less than 5%, the DSP has the discretion to propose interim reconciliation prior to the next PTC adjustment interval. Interim reconciliation proposals should result in a PTC adjustment that will resolve cumulative under or over collections by the time of the next PTC adjustment interval.

[(d) Any reconciliation adjustment shall be recoverable from all customers that were served by the DSP during the reconciliation period whether they continue to be served by the DSP or have switches to an EGS.]

§ 69.1810. Retail rate design.

Retail rates should be designed to reflect the actual, incurred cost of energy and therefore encourage energy conservation. The PTC should not incorporate declining blocks, demand charges, or similar elements [unless there is a cost causation basis justifying the use of such rate design element]. The PTC for a particular customer class may be converted to a time of use design if the Commission finds it to be in the public interest. [In making that determination, the Commission shall consider the effect of a time of use design on the DSP's ability to recover related costs.]

§ 69.1811. Rate change mitigation.

(a) The following provision should apply when a DSP's total retail rate rises by more than 25% following the expiration of a generation rate cap due to wholesale energy prices. In that event DSPs should offer all residential and small business customers of up to 25 kW in maximum registered peak load the opportunity to prepay or defer some portion of the rate increase for as long as 3 years. These mitigation options should be included in the default service program filed for the period that begins with the expiration of the Commission approved generation rate cap. Customers may not be assigned to a rate increase prepay or deferral program without their affirmative consent. DSPs would be able to fully recover the reasonable carrying costs associated with a rate increase deferral program, including associated administrative costs.

(b) DSPs may propose other reasonable rate mitigation strategies that would reflect the incurrence of reasonable costs.

[(c) To the extent the change in rate design to a flat PTC causes significant intraclass cost shifting, an EDC may propose a transition strategy to mitigate the impact on customers.]

§ 69.1812. Information and data access.

The public interest would be served by common standards and processes for access to retail electric customer information and data. This includes customer names and addresses, customer rate schedule and profile information, historical billing data, and real time metered data. Retail choice, demand side response, and energy conservation initiatives can be facilitated if EGSs, curtailment service providers, and other appropriate parties can obtain this information and data under reasonable terms and conditions common to all service territories, with due consideration given to customer privacy.

§ 69.1813. Rate ready billing.

The public interest would be served by the consideration of the availability of rate ready billing in each service territory.

§ 69.1814. Purchase of receivables.

[In developing an initial default service implementation plan, a DSP should address the issue of] ~~The public interest would be served by the consideration of~~ an EGS receivables purchase program ~~in each service territory~~.

§ 69.1815. Customer referral program.

[In developing an initial default service implementation plan, a DSP should address the issue of] ~~The public interest would be served by consideration of~~ customer referral programs in which retail customers are referred to EGSs.

§ 69.1816. Supplier tariffs.

The public interest would be served by the adoption of supplier tariffs that are uniform as to both form and content. Uniform supplier tariffs may facilitate the participation of EGSs in Pennsylvania's retail market, and reduce the potential for mistake or misunderstandings between EGSs and EDCs.

§ 69.1817. Retail choice ombudsman.

The public interest would be served by the designation of an employee as a retail choice ombudsman at each EDC and the Commission. The ombudsman would be responsible for responding to questions from EGSs, monitoring competitive market complaints and facilitate informal dispute resolution between the DSP and EGSs.

ANNEX A

TITLE 52. PUBLIC UTILITIES

PART I. PUBLIC UTILITY COMMISSION

Subpart C. FIXED SERVICE UTILITIES

CHAPTER 54. ELECTRICITY GENERATION CUSTOMER CHOICE

Subchapter A. CUSTOMER INFORMATION

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§ 54.4. Bill format for residential and small business customers.

* * * * *

(b) The following requirements apply only to the extent to which an entity has responsibility for billing customers, to the extent that the charges are applicable. The [provider of last resort] default service provider will be considered to be an EGS for the purposes of this section. Duplication of billing for the same or identical charges by both the EDC and EGS is not permitted.

* * * * *

§ 54.5. Disclosure statement for residential and small business customers

* * * * *

(b) The EGS shall provide the customer written disclosure of the terms of service at no charge whenever:

* * * * *

(3) Service commences from a [provider of last resort] default service provider.

(c) The contract's terms of service shall be disclosed, including the following terms and conditions, if applicable:

* * * * *

(9) The name and telephone number of the [provider of last resort] default service provider.

* * * * *

(h) If the [provider of last resort] default service provider changes, the new [provider of last resort] default service provider shall notify customers of that change, and shall provide customers with their name, address, telephone number and Internet address, if available.

§ 54.6. Request for information about generation supply.

(a) EGSs shall respond to reasonable requests made by consumers for information concerning generation energy sources.

* * * * *

(2) The [provider of last resort] default service provider shall file at the Commission the annual licensing report as required by the Commission's licensing regulations in this chapter and shall otherwise comply with paragraph (1).

Subchapter B. ELECTRIC GENERATION SUPPLIER LICENSING

§ 54.31. Definitions.

* * * * *

[Provider of last resort] Default service provider – [A supplier approved by the Commission under section 2807(e)(3) of the code (relating to duties of electric distribution companies) to provide generation service to customers who contracted for electricity that was not delivered, or who did not select an alternative electric generation supplier, or who are not eligible to obtain competitive energy supply, or who return to the provider of last resort after having obtained competitive energy supply] The incumbent EDC within a certificated service territory or a Commission approved alternative default service provider.

* * * * *

§ 54.32. Application process.

* * * * *

(h) An EDC acting within its certificated service territory as a [provider of last resort] default service provider is not required to obtain a license.

* * * * *

§ 54.41. Transfer or abandonment of license.

* * * * *

(b) A licensee may not abandon service without providing 90 days prior written notice to the Commission, the licensee's customers, the affected distribution utilities and [providers of last resort] default service providers prior to the abandonment of service.

The licensee shall provide individual notice to its customers with each billing, in each of the three billing cycles preceding the effective date of the abandonment.

* * * * *

Subchapter E. COMPETITIVE SAFEGUARDS

* * * * *

§ 54.123. Transfer of customers to default service.

The following standards shall apply to the transfer of a retail customer's electric generation service from an EGS to a default service provider within the meaning of § 54.182:

(a) An EGS shall not transfer a retail customer from its electric generation service to the default service provider without the consent of the default service provider, except in the following situations:

(1) Upon Commission approval of the abandonment, suspension or revocation of an EGS license, consistent with §§ 54.41 and 54.42 (relating to transfer or abandonment of license and license suspension; license revocation).

(2) Upon nonpayment by a retail customer for services rendered by the EGS.

(3) To correct an unauthorized or inadvertent switch of a retail customer's account from default service to an alternative EGS's service, consistent with 52 Pa. Code § 57.177 (pertaining to customer dispute procedures).

(4) Upon the normal expiration of contracts.

(b) An EGS may initiate transfers in the above situations through standard electronic data interchange protocols.

(c) The Commission may impose a penalty for every retail customer transferred to default service in violation of § 54.123, consistent with 66 Pa.C.S. §§ 3301-3316 (relating to violations and penalties).

Subchapter G. DEFAULT SERVICE

§ 54.181. Purpose.

This subchapter implements § 2807(e) of the Electricity Generation Customer Choice and Competition Act, 66 Pa.C.S. §§ 2801-2812, pertaining to an EDC's obligation to serve retail customers at the conclusion of the restructuring transition period. These regulations ensure that all retail customers who do not choose an alternative EGS, or who contract for electric energy that is not delivered, have access to generation supply at prevailing market prices. The EDC or other approved entity shall fully recover all reasonable costs for acting as a default service provider of electric generation supply to all retail customers in its certificated distribution territory.

§ 54.182. Definitions.

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

Alternative energy portfolio standards – A requirement that a certain percentage of electric energy sold to retail customers in the Commonwealth of Pennsylvania by EDCs and EGSs be derived from alternative energy sources, as defined in the Alternative Energy Portfolio Standards Act, 73 P.S. § 1648.1, *et seq*.

Commission – The Pennsylvania Public Utility Commission.

Competitive bid solicitation process – A fair, transparent, and non-discriminatory process by which a DSP awards contracts for electric generation supply to qualified suppliers who submit bids.

Default service –

(i) Electric generation supply service provided by a default service provider to a retail electric customer who is not receiving generation service from an EGS.

(ii) Electric generation supply service provided pursuant to a Commission approved default service plan.

Default service implementation plan – The schedule of competitive bid solicitations and spot market energy purchases, all technical requirements, and all related forms and agreements.

Default service procurement plan – The electric generation supply acquisition strategy the DSP will utilize in satisfying its default service obligations, including the manner of compliance with the alternative energy portfolio standards requirement.

Default service program – A filing submitted to the Commission by the DSP that identifies a procurement plan, an implementation plan, a rate design to recover all reasonable costs, and all other elements identified at § 54.185.

DSP – Default service provider – The incumbent EDC within a certificated service territory or a Commission approved alternative supplier of electric generation service.

Default service rates – The rates billed to default service customers resulting from compliance with a Commission approved default service program.

EDC – Electric Distribution Company – This term shall have the same meaning as defined in 66 Pa.C.S. § 2803.

EGS – Electric Generation Supplier – This term shall have the same meaning as defined in 66 Pa.C.S. § 2803.

FERC – The Federal Energy Regulatory Commission.

Maximum registered peak load - The highest level of demand for a particular customer, based on the PJM Interconnection, LLC, peak load contribution standard, or its equivalent, and as may be further defined by the EDC tariff in a particular service territory.

Prevailing market prices – Prices that are available in the wholesale market at particular points in time for electric generation supply.

PTC – Price-to-compare – The rate charged to a retail electric customer by the DSP for default service.

Retail customer or retail electric customer – These terms shall have the same meaning as defined in 66 Pa.C.S. § 2803.

RTO – Regional transmission organization – A FERC approved regional transmission organization.

Spot market energy purchase – The purchase of an electric generation supply product, either directly from an RTO or via a competitive procurement process, where the energy component of the purchase reflects the hourly ~~in~~ pricing ~~in~~ a FERC-approved real time or day ahead energy market.

§ 54.183. Default service provider.

(a) The DSP shall be the incumbent EDC in each certificated service territory, except as provided for pursuant to § 54.183(b).

(b) The DSP may be changed by one of the following processes:

(1) An EDC may petition the Commission to be relieved of the default service obligation.

(2) An EGS may petition the Commission to be assigned the default service role for a particular EDC service territory.

(3) The Commission may propose through its own motion that an EDC be relieved of the default service obligation.

(c) The Commission may reassign the default service obligation to an alternative DSP if it finds it to be necessary for the accommodation, safety and convenience of the public. Such a finding would include an evaluation of the incumbent EDC's operational and financial fitness to serve retail customers, and its ability to provide default service under reasonable rates and conditions. In such circumstances, the Commission will announce through an order a competitive process to determine the alternative DSP.

(d) When the Commission finds that an EDC should be relieved of the default service obligation, the competitive process for the replacement of the default service provider shall be as follows:

(1) Any entity that wishes to be considered for the role of the alternative DSP shall file a petition pursuant to 66 Pa.C.S. § 2807(e)(3).

(2) Petitioners shall demonstrate their operational and financial fitness to serve and their ability to comply with all Commission regulations, orders and applicable laws.

(3) If no petitioner can meet this standard, the incumbent EDC shall be required to continue the provision of default service.

(4) If more than one petitioner meets the standard provided in § 54.183(d)(2), the Commission shall approve the DSP best able to fulfill the obligation in a safe, cost-effective, and efficient manner ,consistent with 66 Pa.C.S. §§ 1103, 1501, and 2807(e).

(5) Any petitioner that is approved to act as an alternative DSP shall comply with all applicable provisions of the Public Utility Code, regulations, and any conditions imposed in approving the petition to act as an alternative DSP.

§ 54.184. Default service provider obligations.

(a) A DSP shall be responsible for the reliable provision of default service to all retail customers who are not receiving generation services from an EGS within the certificated territory of the EDC that it serves.

(b) A DSP shall comply with the Public Utility Code, 66 Pa.C.S. 101, *et seq.*, and 52 Pa. Code § 1.1, *et seq.* to the extent that such obligations are not modified by this subchapter or waived pursuant to 52 Pa. Code § 5.43 (pertaining to waiver of Commission regulations).

(c) A DSP shall continue the universal service and energy conservation programs in effect in the EDC's certificated service territory or implement, subject to

Commission approval, similar programs consistent with the provisions of the Electricity Generation Customer Choice and Competition Act, 66 Pa.C.S. §§ 2801-2812. The Commission will determine the allocation of these responsibilities between an EDC and an alternative DSP when an EDC is relieved of its DSP obligation.

§ 54.185. Default service programs and periods of service.

(a) A DSP shall file a default service program with the Secretary's Bureau no later than fifteen months prior to the conclusion of the currently effective default service plan or Commission approved generation rate cap for that particular EDC service territory, unless the Commission authorizes another filing date. Thereafter, the DSP shall file its programs consistent with schedules identified by the Commission.

(b) Default service programs shall comply with all Commission regulations pertaining to documentary filings at 52 Pa. Code § 1.1, *et seq*. (pertaining to rules of administrative practice and procedure), except when modified by this subchapter. The DSP shall serve copies of its default service program on the Pennsylvania Office of Consumer Advocate, Pennsylvania Office of Small Business Advocate, the Commission's Office of Trial Staff, EGSs registered in the service territory, and the RTO in whose control area the default service provider is operating. Copies shall be provided upon request to other EGSs.

(c) The first default service program shall be for a period of two to three years, or for a period necessary to comply with § 54.185(d)(4), unless another period is authorized by the Commission. Subsequent program terms will be determined by the Commission.

(d) A default service program shall include the following elements:

(1) A procurement plan identifying the DSP's electric generation supply acquisition strategy for the period of service. The procurement plan should also identify the means of satisfying the minimum portfolio requirements of the

Alternative Energy Portfolio Standards Act, 73 P.S. § 1648.1, *et seq.*, for the period of service.

(2) An implementation plan that identifies the schedules and technical requirements of all competitive bid solicitations and spot market energy purchases, consistent with § 54.186.

(3) A rate design plan that will recover all reasonable costs of default service, including a schedule of rates, rules and conditions of default service in the form of proposed revisions to its tariff.

(4) Documentation that the program is consistent with the legal and technical requirements pertaining to the generation, sale and transmission of electricity of the RTO or other entity in whose control area it is providing service. The default service procurement plan's period of service shall align with the planning period of that RTO or other entity.

(5) Contingency plans to ensure the reliable provision of default service in the event a wholesale generation supplier fails to meet its contractual obligations.

(6) Copies of any agreements or forms to be used in the procurement of electric generation supply for default service customers. This shall include all documents utilized as part of the implementation plan, including supplier master agreements, request for proposal documents, credit documents, and confidentiality agreements. Where applicable, the default service provider shall use standardized forms and agreements that have been approved by the Commission.

(7) A schedule identifying all generation contracts of greater than 2 years in effect between a DSP, where it is the incumbent EDC, and retail customers in that service territory. The schedule should identify the load size and end date of the contracts.

(e) The Commission may, following notice and opportunity to be heard, direct that some or all DSPs file joint default service programs to acquire electric generation supply for all of their default service customers. In the absence of such a directive, some or all DSPs may jointly file default service programs or coordinate the scheduling of competitive bid solicitations to acquire electric generation supply for all of their default service customers. A multi-service territory procurement and implementation plan shall comply with § 54.186.

§ 54.186. Default service procurement and implementation plans.

(a) A DSP shall acquire electric generation supply at prevailing market prices for default service customers in a manner consistent with procurement and implementation plans approved by the Commission.

(b) A DSP's procurement plan shall adhere to the following standards:

(1) The procurement plan should be designed to acquire electric generation supply at prevailing market prices to meet the DSP's anticipated default service obligation at a reasonable cost ~~at the lowest reasonable long-term costs~~.

(2) DSPs with loads of 50 MW or less shall evaluate the cost and benefits of joining with other DSPs or affiliates in contracting for electric supply.

(3) Procurement plans may include solicitations and contracts whose duration extends beyond the program period.

(4) All electric generation supply should be acquired either through competitive bid solicitation processes, spot market energy purchases, or a combination of both.

(5) The DSP's supplier affiliate may participate in any competitive bid solicitation process utilized as part of the procurement plan subject to the following conditions:

(i) The DSP shall propose and implement protocols to ensure that its supplier affiliate does not receive an advantage in either the solicitation and evaluation of competitive bids, or any other aspect of the implementation plan.

(ii) The process shall comply with the codes of conduct promulgated by the Commission at § 54.122 (relating to code of conduct).

(c) A DSP's implementation plan shall adhere to the following standards:

(1) Any competitive bid solicitation process utilized as part of the default service implementation plan shall include:

(i) A bidding schedule.

(ii) A definition and description of the power supply products on which potential suppliers shall bid.

(iii) Bid price formats.

(iv) The time period during which the power will need to be supplied for each power supply product.

(v) Bid submission instructions and format.

(vi) Price-determinative bid evaluation criteria.

(vii) Relevant load data, including the following:

(A) Aggregated customer hourly usage data for all retail customers.

(B) Number of retail customers.

(C) Capacity peak load contribution figures by rate schedule.

(D) Historical monthly retention figures by rate schedule.

(E) Estimated loss factors by rate schedule.

(F) Customer size distribution by rate schedule.

(2) The default service implementation plan shall include fair and non-discriminatory bidder qualification requirements, including financial and operational qualifications, or other reasonable assurances of any supplier of electric generation services' ability to perform.

(3) Any competitive bid solicitation process utilized as part of the implementation plan shall be subject to monitoring by the Commission or an

independent third party evaluator selected by the DSP in consultation with the Commission. Any third party evaluator shall operate at the direction of the Commission. Commission staff and any third party evaluator involved in monitoring the procurement process shall have full access to all information pertaining to the competitive procurement process, either remotely or where the process is administered. Any third party evaluator retained for purposes of monitoring the competitive procurement process shall be subject to confidentiality agreements identified in § 54.185(d)(6).

(4) The DSP and/or third party evaluator shall review and select winning bids procured through a competitive bid solicitation process in a non-discriminatory manner based on the price determinative bid evaluation criteria set forth consistent with § 54.186(b)(2)(vi).

(5) The bids submitted by a supplier in response to any competitive bid solicitation process shall be treated as confidential pursuant to the confidentiality agreement approved by the Commission pursuant to § 54.185(d)(6). The DSP, the Commission, and any third party involved in the administration, review or monitoring of the bid solicitation process shall be subject to this confidentiality provision.

(d) The DSP may petition for modifications to the approved procurement and implementation plans in the event of material changes in wholesale energy markets to ensure the acquisition of sufficient supply at prevailing market prices. The DSP shall monitor changes in wholesale energy markets to ensure that its procurement plan continues to reflect the incurrence of reasonable costs, consistent with 66 Pa.C.S. § 2807(e)(3).

§ 54.187. Default service rate design and the recovery of reasonable costs.

(a) The costs incurred for providing default service shall be recovered through a default service rate schedule. This rate schedule shall be designed to recover fully all reasonable costs incurred by the DSP during the period default service is provided to customers, based on the average cost to acquire supply for each customer class considerations of demand-related costs, seasonal pricing differences, and other cost elements.

(b) Except for rates available consistent with 54.187(f), each default service customer shall be offered a single rate option, which shall be identified as the PTC.

(c) The PTC charged to default service customers shall not decline solely because of an ~~with the~~ increase in kWh of electricity used by a default service customer in a billing period except where such a decline is based on the actual cost of providing service to the customer.

(d) The PTC shall be designed to recover all default service costs, including all generation, transmission, and other default service cost elements, incurred in serving the average member of a customer class. An EDC's default service costs shall not be recovered through the distribution rate. Costs currently recovered through the distribution rate, which are reallocated to the default service rate, shall not be recovered through the distribution rate.

(e) A DSP shall use an automatic energy adjustment clause, consistent with 66 Pa.C.S. § 1307 and 52 Pa. Code § 75.1, *et seq*. (pertaining to alternative energy portfolio standards), to recover all reasonable costs incurred through compliance with the Alternative Energy Portfolio Standards Act, 73 P.S. §1648.1, *et seq*.

(f) A DSP may use an automatic energy adjustment clause, consistent with 66 Pa.C.S. § 1307, to recover all reasonable costs incurred through compliance with its DSP to acquire electricity to serve the requirements of its ~~prudently incurred non-alternative energy~~ default service customers~~costs~~.

(g) The default service rate schedule shall include rates that correspond to demand side response and demand side management programs, as defined at 73 P.S. §

1648.2, if the Commission mandates such rates pursuant to its authority under 66 Pa.C.S. § 101, *et seq.*

(h) Default service rates shall be adjusted on an annual ~~quarterly~~ basis, or more frequently, upon reasonable request by the DSP or where the DSP's accumulated over/under recovery of purchased electric costs exceed 5 percent of its total anticipated costs for that period, for all customer classes with a maximum registered peak load up to 25 kW, in order to ensure the recovery of costs reasonably incurred in acquiring electricity at prevailing market prices and to reflect the seasonal cost of electricity. DSPs may propose alternative divisions of customers by maximum registered peak load to preserve existing customer classes.

(i) Default service rates shall be adjusted on an annual ~~quarterly~~ basis, or more frequently upon reasonable request by the DSP or where the DSPs accumulated over/under recovery of purchased electric costs exceed~~,~~ 5 percent of its total costs estimated for that annual period, for all customer classes with a maximum registered peak load of 25 kW to 500 kW, in order to ensure the recovery of costs reasonably incurred in acquiring electricity at prevailing market prices and to reflect the seasonal cost of electricity. DSPs may propose alternative divisions of customers by maximum registered peak load to preserve existing customer classes.

(j) Default service rates shall be adjusted on a monthly basis, or more frequently upon reasonable request by the DSP or where the DSPs accumulated over/under recovery of purchased electric costs exceed 5 percent of its total costs estimated for that annual period, for all customer classes with a registered peak load of equal to or greater than 500 kW in order to ensure the recovery of costs reasonably incurred in acquiring electricity at prevailing market prices and to reflect the seasonal cost of electricity. DSPs may propose alternative divisions of customers by registered peak load to preserve existing customer classes.

(k) ~~(k)~~ When a supplier fails to deliver electric generation supply to a DSP, the DSP shall be responsible for acquiring replacement electric generation supply consistent with its Commission approved contingency plan and the DSP shall be entitled to recover such costs through an adjustment to its PTC. When necessary to procure electric generation supply before the implementation of a contingency plan, a DSP shall acquire supply at prevailing market prices and shall fully recover all reasonable costs associated with this activity. In this circumstance, the prevailing market price will be the price of spot market energy purchases in FERC approved energy markets. The DSP shall follow acquisition strategies that reflect the incurrence of reasonable costs, consistent with 66 Pa.C.S. § 2807(e)(3), when selecting from the various options available in these energy markets.

(l) The over/(under) recovery component, including carrying charges calculated using the legal rate of interest, of any quarterly, monthly, or other reconciliation shall be recoverable from all customers who received DSP service during the period being reconciled.

§ 54.188. Commission review of default service programs and rates.

(a) A default service program will initially be referred to the Office of Administrative Law Judge for further proceedings as may be required.

(b) The Commission will issue an order within six months of a program's filing with the Commission on whether the default service program demonstrates compliance with this subchapter and the provisions of the Electricity Generation Customer Choice and Competition Act, 66 Pa.C.S. §§ 2801-2812.

(c) Upon entry of the Commission's final order, the DSP shall acquire generation supply for the period of service in a manner consistent with the terms of the approved procurement and implementation plans consistent with the standards identified at § 54.186.

(d) Upon receiving written notice, the Commission will have one business day, to approve or disapprove the results of each competitive bid solicitation process utilized by the DSP as part of its procurement plan. If the Commission does not act within one business day, the results of the process will be deemed approved. The Commission will not certify or otherwise approve or disapprove a DSP's spot market energy purchases made as part of its procurement plan as these purchases are already deemed recoverable in the approval of the Default Service Program. The Commission will monitor the DSP's adherence to the terms of the approved default service program and all provisions of the Electricity Generation Customer Choice and Competition Act, 66 Pa.C.S. §§ 2801-2812. The Commission may, in its discretion, initiate an investigation regarding the DSP's implementation of its default service program and, at the conclusion of such investigation, order such remedies as may be lawful and appropriate.

(e) The DSP shall adhere to the following procedures in obtaining approval of default service rates and providing notice to default service customers:

(1) The DSP shall provide all customers notice of the initial default service rates and terms and conditions of service either 60 days before their effective date, or 30 days after bidding has concluded, whichever is sooner, unless another time period is approved by the Commission. The DSP shall also provide written notice to the named parties identified in § 54.185(b) containing an explanation of the methodology used to calculate the price for electric service.

(2) After the initial steps of a default service procurement and implementation plan are completed, the DSP shall file with the Commission tariff supplements designed to reflect, for each customer class, the rates to be charged for default service. The tariff supplements shall be accompanied by supporting documentation adequate to demonstrate adherence to the procurement plan approved by the Commission, the procurement plan results and the translation of those results into customer rates.

(3) A customer or party identified in § 54.185(b) may file exceptions to the initial default service tariffs within 20 days of the date the tariffs are filed with the Commission. The exceptions shall be limited to whether the DSP properly implemented the procurement plan approved by the Commission and accurately

calculated the rates. The Commission will resolve any filed exceptions by order issued no later than the 10th day prior to the effective date of the initial default service tariffs. ~~Notwithstanding any filed exceptions, the Commission may allow the default rates to become effective pending the resolution of those exceptions~~.

(f) The DSP shall submit tariff supplements on an annual basis, or more frequently upon reasonable request by the DSP or where the DSPs accumulated over/under recovery of purchased electric costs exceed 5 percent of its total costs estimated for that annual period, ~~quarterly or more frequent basis~~, consistent with § 54.187 (g~~f~~) and (h~~g~~), to revise default service rates to ensure the recovery of costs reasonably incurred in acquiring electricity at prevailing market prices. The DSP shall provide written notice to the named parties identified in § 54.185(b) of the proposed rates at the time of these tariff filings. A customer or the parties identified in § 54.185(b) may file exceptions to the default service tariffs within 20 days of the date the tariffs are filed with the Commission. The exceptions shall be limited to whether the DSP has properly implemented the procurement plan approved by the Commission and accurately calculated the rates. The DSP shall post the revised PTC for each customer class within one business day of its effective date to its public internet domain to enable customers to make an informed decision about electric generation supply options.

§ 54.189. Default service customers.

(a) At the conclusion of an EDC's Commission approved generation rate cap, all retail customers who are not receiving generation service from an EGS shall be assigned to the Commission approved default service program in that service territory.

(b) A DSP shall accept all applications for default service from new retail customers and retail customers who switch from an EGS, if the customers comply with all Commission regulations pertaining to applications for service, including those at 52 Pa. Code § 56.1, *et seq*. (pertaining to standards and billing practices for residential customers)

(c) A DSP shall treat a customer who leaves an EGS and applies for default service as it would a new applicant for default service.

(d) A default service customer may choose to receive its generation service from an EGS at any time, if the customer complies with all Commission regulations pertaining to changing generation service providers at 52 Pa. Code § 57.1., *et seq.* (pertaining to electric service). <u>A DSP may propose switching rules that require annualized fixed price customers to remain on that service for 12 months or alternatively pay an exit fee for switching early.</u>

(e) A DSP may not charge a fee to a retail customer that changes its generation service provider in a manner consistent with Commission regulations <u>except to recover a prior undercollection or as required by PUC approved switching rules</u>.

CHAPTER 57. ELECTRIC SERVICE

Subchapter M: STANDARDS FOR CHANGING A CUSTOMER'S ELECTRICITY GENERATION SUPPLIER

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§ 57.178. [Provider of Last Resort] Default service provider.

This subchapter does not apply when the customer's service is discontinued by the EGS and subsequently provided by the [provider of last resort] default service provider because no other EGS is willing to provide service to the customer.

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Example 1 - Small C&I customers with same demand and different usage profiles.

Demand =	25	kw		
Customer 1 Energy (<u>low load factor</u>)	6250	kwh	250	hours
Customer 2 Energy (<u>high load factor</u>)	12500	kwh	500	hours

Rate	Variable Dist	CTC	Transmission	Energy	Total
1st 80 Hours use	$ 0.0365	$ 0.0823	$ 0.0129	$ 0.1277	$ 0.2594
Next 80 Hours use	$ 0.0172	$ 0.0341	$ 0.0061	$ 0.0693	$ 0.1267
Additional use	$ 0.0109	$ 0.0215	$ 0.0038	$ 0.0502	$ 0.0864
Over 400 Hours use	$ 0.0048	$ 0.0095	$ 0.0017	$ 0.0319	$ 0.0479

	Customer 1 Calculation	Customer 2 Calculation
1st 80 Hours use	$ 518.80	518.80
Next 80 Hours use	$ 253.40	253.40
Additional use	$ 194.40	518.40
Over 400 Hours use	$ -	119.75
Total	$ 966.60	1,410.35
kwh	6250	12500
Current Rate ($/kwh)	$ 0.1547	$ 0.1128
Class average rate ($/kwh)	$ 0.13030	$ 0.1303
Change to get to class average rate	-16%	15%

Example 2 - Large C&I Customers with same demand and different usage profile.

Demand =	1000	kw		
Cusomert 1 Energy (<u>low load factor</u>)	300000	kwh	300	hours
Customer 2 Energy (<u>high load factor</u>)	650000	kwh	650	hours

Rate	Variable Dist	CTC	Transmission	Energy	Total
Demand Charge	$ 1.680	$ 4.680	$ 0.800	$ 7.160	$ 14.320
Next 80 Hours use	$ 0.0091	$ 0.0251	$ 0.0043	$ 0.0549	$ 0.0934
Additional use	$ 0.0059	$ 0.0149	$ 0.0025	$ 0.0391	$ 0.0624
Over 400 Hours use	$ 0.0018	$ 0.0048	$ 0.0008	$ 0.0237	$ 0.0311

	Customer 1 Calculation	Customer 2 Calculation
Demand Charge	$ 14,320	$ 14,320
1st 150 hours use	$ 14,010	$ 14,010
Next 150 Hours Use	$ 9,360	$ 9,360
Additional use	$ -	$ 10,885
Total	$ 37,690	$ 48,575
kwh	300000	650000
$/kwh	$ 0.1256	$ 0.0747
Class Avg Rate ($/kwh)	$ 0.0789	$ 0.0789
Change to get to class average rate	-37%	6%