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

Advance Notice Of Final Rulemaking Order

Default Service and Retail Electric Markets — Docket No. M-00072009

Proposed Policy Statement

REPLY COMMENTS OF DIRECT ENERGY SERVICES, LLC

INTRODUCTION

Direct Energy Services, LLC ("Direct Energy") submits these reply comments pursuant to the Commission's Advance Notice of Final Rulemaking Order ("ANOFR") and its related Proposed Policy Statement Order ("Policy Statement") adopted February 8, 2007. As was done for the first round of Comments, Direct Energy submits these reply comments in both dockets.

The **end-state** electricity market design is not a negotiable product. If the Commission wants truly robust competition and innovative product options for the customers, only one overall market design will work, recognizing that there may be a few ways to implement the design. In reading the Comments presented by suppliers and private sector small customers[1], there is a high degree of uniformity among the messages. The comments of other parties however, seem to contain significant distortions in the definitions and the interpretations of the PUC's proposals in an effort to advance their own specific policy goals, which may or may not

---

1 See comments of RESA, NEM, Con Ed Solution, Direct Energy Services, Hess, Strategic Energy, Reliant and Economic Growth through Competitive Energy Markets Coalition.

be consistent with the overall policy goal of the Commonwealth. The policy of this Commonwealth, it apparently bears repeating, is **customer choice** of generation suppliers.

A successful retail market design includes, among other things, a market-responsive default service rate. It must include the availability of customer usage and billing data in an accessible and readily available format. The market design must link the obligation to bill and collect with the entity that "owns" the customer. Finally, the market rules, regulations and standards should be consistent across the state. These include codes of conduct for utility and affiliate behavior, operational protocols and tariffs and consumer protection and compliance issues. The issues that the Commission presented in its Policy Statement, such as the customer referral program and the retail market ombudsman should be incorporated into the uniform rules and business practices utilized around the state.

I. Default Service Rates Should Reflect the Prevailing Market Price.

A default service rate that is reflective of current market conditions is the bedrock of a competitive market. The Commission rightly believes that fixed rate options should be provided by the competitive marketplace. Direct Energy fully supports this conclusion. Others in this proceeding who do not support this conclusion rely on policy objectives not articulated in the Electric Choice Act or on arguments that are fundamentally flawed.

A. Procurement of Power should be done in a manner consistent with the Prevailing Market Price Standard and in a manner that promotes the policy objectives in the Electric Choice Act.

1. PPL Comments on Procurement

PPL Electric Utilities Corp ("PPL"), for example, "believes that a statewide descending clock auction would . . . be a better approach for obtaining default supply." (PPL Comments at p. 8) In its support of such a mechanism, no benefit to the customers is ever mentioned, nor is any furtherance of the policy of the Commonwealth of **Customer Choice** of generation supplier.

PPL suggests that the state-wide auction would be less burdensome on the Commission. (PPL Comments at p. 7) PPL also states that the state-wide approach would not "disrupt the wholesale market", a market in which PPL is a significant state-wide participant. (PPL Comments at pp. 7-8) Finally, PPL states that it would minimize the risk of inconsistent regulatory treatment of individual DSPs. (PPL Comments at p. 8) None of these are a valid reason to fail to move to a market-reflective default service.

PPL also resists relying on the spot market for purchases, using volatility as a scare tactic. They state "monthly electricity pricing in the PPL zone within PJM between 2002 and 2005 increased as much as 52% in a month or decreased by 32%. Prices have varied as much as 200% in a year." (PPL Comments at p. 12) PPL presented this testimony in its recent competitive bridge plan hearing. In that hearing, they submitted monthly PJM pricing data for 49 months. What they didn't mention in the testimony then or in their filing in this docket is that in 44 of the 49 months, the PJM monthly clearing price in the PPL zone was **less expensive** than the PPL tariff price for residential customers. PPL objected to this finding at the hearing and suggested that the math presented was incorrect. Even when adjusted using PPL's own math (which was questionable at best), 32 of the 49 monthly PJM prices were lower than the PPL tariff price.[2] Some entities may argue that volatility is bad for consumers. That is debatable. The bottom line however, is that lower prices are good for consumers. The results are irrefutable. **Market-based, shorter term default service rates result in lower prices to default service customers.**

2. Allegheny Power Comments on Procurement

Allegheny Power ("Allegheny") suggests a form of "laddering" of contracts. Allegheny certainly is sending mixed signals in its comments. Allegheny states that "the premise behind

[2] See Appendix I, Exhibit FPL-4, Oral Rejoinder Testimony of Frank Lacey, in the *Petition of PPL Electric Utilities Corporation, For Approval of a Competitive Bridge Plan*, Docket No. P-00062227, discussed at transcript pages 218 – 222, December 19, 2006.

recent arguments for a complex 'portfolio' approach to default service is that it is possible for a complex 'portfolio' to provide better prices than the market. This is simply untrue, and contrary to all the evidence that led Pennsylvania . . . to seek access to the benefits of retail and wholesale competition . . . ." (Allegheny Comments at p. 7) Direct Energy agrees with this conclusion. However, it is therefore confusing when Allegheny later suggests that "[s]upply contracts can vary by customer class groupings (and/or even consist of mixes of contract terms for each group), and the expiration dates of the contracts can be staggered so that only part of a customer class's load turns over at any one time." (Allegheny comments at p. 8) This "complex portfolio" approach advocated by Allegheny is contrary to its own recommendations and it neither mitigates volatility nor mitigates price increases. It only mitigates competitive choices.

3. Constellation Comments on Procurement

The Constellation Energy Group Companies ("Constellation") state that price adjustments negate "wholesale suppliers' abilities to manage portfolios and analyze and account for market changes and therefore does not provide for price stability." (Constellation Comments at p. 11) Constellation asserts that "price diversity and market-priced service can be achieved, with some measure of price stability, by the Commission's proscribed competitive procurement structure which couples laddered contracts with multiple procurements leading up to the date of default service delivery." (Constellation Comments at p. 11) This argument belies the policy of the Commonwealth which is **customer choice** of generation service provider, not **wholesale provider's choice** of electricity service to customers. Constellation is simply advancing retail electric rate policies that will best advantage its wholesale supply business. That is not the proper basis on which to make such policy determinations.

4. PECO Comments on Procurement

PECO Energy Company ("PECO") seemingly goes further than the other EDCs, supporting a state-wide procurement with laddered contracts and advocating contract terms greater than three years for commodity supply. (PECO comments pp. 4-8) They offer no benefits that will accrue to the customers with their suggestions.

5. EAPA Comments on Procurement

PPL and Energy Association of Pennsylvania ("EAPA") support long-term contracts through their suggested definitions of "prevailing market price". They both suggest that "the price for each of these different [energy] products over the agreed-upon term is a prevailing market price at the time the generation supply is purchased." (EAPA Comments at p. 5, PPL Comments at p. 5) The instruction in the Electric Choice Act is to acquire power at the prevailing market price when energy is not delivered from a supplier or when a customer fails to make a competitive choice – not years in advance of that circumstance. It is clear from a reading of the entire section that the default customer must receive a price that reflects the price prevailing at or around the time that the customer utilizes the power. The EAPA/PPL interpretation – which is shared by OCA, OSBA and many others – would mean that the "prevailing market price" standard would be met by whatever price a contract sets, even if the price is set years in advance. To suggest that a customer will see a "prevailing market price" three years after a contract for the delivery of power is executed strains credibility. Default service is a customer call option on energy. This EAPA/PPL definition is akin to suggesting that someone could purchase a call option on a stock with a strike date three years forward at the same price three years in the future as he could today.

6. Duquesne Light Comments on Procurement

Duquesne Light Company ("Duquesne") commented "[a]ttempts to frequently adjust retail rates for residential customers (e.g., in New York and Massachusetts) and attempts to rely on a portfolio approach with reconciliation (e.g., New York) have in many instances resulted in more rate shock for customers and less retail shopping than experienced in Duquesne's service area." (Duquesne Comments at p. 7) Certainly, with frequently adjusted pricing, customers will see price variations. There has been no evidence presented that New York customers have experienced "rate shock". In fact, in Pike County public input meetings, customers with homes and/or businesses in both New York and Pennsylvania asked why their Pennsylvania properties weren't priced like New York customers. The risk of price shock is much greater under long-term contracts than under short-term default contracts. If nothing else, the impacts of inflation are greater with long-term procurements. Additionally, if timed incorrectly, price shocks will be lasting with long-term contracts. With frequent adjustments, prices will come down with the market.

Duquesne also states that "[s]maller customers and especially residential customers do not want to be exposed to short-term wholesale market price volatility while competitive retail markets continue to develop." (Duquesne Comments at p. 16) While on its face, this does not seem like an outrageous assertion (in fact the claim is suspect because it is based on testimonials from consumer advocates around the country – not consumers), it does not reflect the whole story. If presented with the question, "Do you want stable prices?" the answer may be yes. However, if the question is, do you want lower prices and competitive options, or do you want stable – and potentially higher rates – the answer undoubtedly will be lower prices and competitive options. If residential customers in Duquesne's service territory had been on monthly priced service, Direct Energy estimates that they would have saved over $75 million

dollars versus the POLR III rate during the first two years of POLR III.[3] Only if customers are presented with these facts can an accurate estimation of customer opinion be obtained.

Duquesne dismisses the argument that customers should see price signals stating that the argument "is dampened however, to the extent that default service rates could reflect 'stale' prices due to laddering and/or reconciliation." (Duquesne Comments at p. 17) In an age where discussion of AEPS dominates much of the day, when global warming, greenhouse gas initiative and carbon taxes consume much of our time, clearly it is incorrect to suggest that short-term price signals are not important. Of course, short-term price signals are crucially necessary so that customers can react to energy prices and allocate energy resources efficiently. In essence, by its very statement, Duquesne is really telling the Commission why long-term contracts are fundamentally flawed from a policy perspective.

Duquesne further argues for long-term contracts stating "large increases in energy prices, such as those experienced recently, are extremely difficult to control and manage." Duquesne is correct in that large increases in energy prices are difficult to control. Yet for some reason, Duquesne thinks that it can control them better than others. They simply cannot. The energy market is priced based on global fuel commodities and demand. Energy prices across the country and the world have risen over the last several years. Neither Duquesne nor any other utility is in a position to control energy prices. The question for the Commission is whether the Commission wants the utilities to try to manage the generation risks for the customers or if the **customers in the Commonwealth should be given the opportunity to do so by receiving timely pricing signals and having the real ability to choose** their own electric generation

---

3 See Appendix II, Intelometry Inc., Power Price Report, Pittsburgh Market (Duquesne Light), 1-1-05 to 11-30-06, December 2006.

supply in order to mitigate or avoid such price changes. The Electric Choice Act is clear on which path the Commission should pursue.

7. OCA Comments on Procurement

The Pennsylvania Office of Consumer Advocate ("OCA") suggests that for residential customers, "[c]ontracts should be laddered to minimize risk." (OCA Comments at p. 62) Interestingly, OCA states in its comments that it is clear "that for residential customers default service will remain the primary means by which essential electricity service is made available to customers on reasonable terms and conditions." (OCA Comments at p. 3) This conclusion can only be premised on the basis that the OCA believes that its policies will be adopted or that competition won't deliver better prices and products to residential customers than regulation. Laddering of contracts in fact, gives rise to the least competitive of all market scenarios. No matter what the ultimate definition of "prevailing market price" adopted by the Commission, laddering contracts cannot meet that definition. Laddering contracts forces the averaging of prices over time and yields the least competitive results. For example, if a three year laddering approach was taken (similar to the New Jersey model that was rejected by the Commission in its ANOFR and Policy Statement), the resulting price is the average of three different solicitations, each of which was argued to be the "prevailing market price". Clearly, the average of three "prevailing market prices" cannot be the "prevailing market price".

The OCA argues for three pages that the Commission should not require price adjustments on a quarterly or more frequent basis. (OCA Comments at pp. 18-20) First the OCA states that the Commissions proposal is based on the "mistaken assumption" that prevailing market prices are "short-term prices". This is not a mistaken assumption. The common definition of the word prevailing is: 1) Most frequent or common; predominant; 2) Generally

current; widespread.[4] Again, the call option analogy utilized above is appropriate. The market price for an option on a stock will **not** be the same over the course of any material length of time. It will always be reflective of prevailing market conditions.

OCA also "submits that there is no obvious benefit from the use of quarterly price changes in the stimulation of retail competition." It cites to the gas markets and suggests that quarterly pricing "might act as a barrier to customer choice." With all due respect to the OCA, not one of the competitive supplier entities that has intervened in this docket has suggested that market-based default service is a barrier to retail competition. **These competitive supplier intervenors compete actively in competitive energy markets globally on a daily basis.** Surely, if quarterly pricing was a barrier to competition, one of the suppliers would have mentioned it. (Adjustments due to **reconciliation**, on the other hand, are **anti-competitive**.)

The OCA also states that the "default service rate should be a stable price that adjusts no more than on an annual basis. Prices that change more frequently can introduce significant problems of affordability and bill management for customers. With unknown and unpredictable changes during a 12-month period, the affordability of basic electric service can be jeopardized (particularly for low to moderate income households), payment plans can be negatively impacted, and budget billing becomes extremely difficult to implement and maintain." (OCA Comments at pp.18-19) These arguments can be made for a rate period of any duration – 3 months or 3 years. Pike County residents would be happier with shorter term pricing. <u>The residents asked to be on a monthly price, like customers in New York</u>. Payment plans and budget plans are just as impacted by annual rate changes as they are by quarterly rate changes. Unless every customer on a budget plan signs up on the first day of the plan year (which is not

---

[4] Prevailing. Dictionary.com. *The American Heritage® Dictionary of the English Language*, Fourth Edition. Houghton Mifflin Company, 2004. http://dictionary.reference.com/browse/prevailing (accessed: March 20, 2007)

feasible due to different meter read dates), then the budgeting has to overlap multiple budget periods. The entire energy industry is properly concerned about the ability of low income customers to afford the utility services they need; but the answer must be state-wide or individual company low income energy assistance plans - not skewing the overall default service rate structure to assure that the least fortunate can deal with any contingency. The fair extension of OCA's argument is that all EDC distribution rates should be reduced to the level at which the most payment troubled customer can afford. This arguments presented by OCA are red herrings.

8. OSBA Comments on Procurement

In arguing for default service contracts of up to three years, the Pennsylvania Office of Small Business Advocate ("OSBA") claims that the "Commission has articulated no rationale for subjecting small business customers with peak loads of 25-500 kW to greater price volatility than the other identified customer groups." In fact, there is no evidence that the quarterly pricing or annual contracts proposed by the Commission will lead to greater price volatility. In fact, evidence and logic dictates that the volatility is lower when prices change more frequently. If prices change less frequently, it is likely that the change will be larger in magnitude than if prices change on a regular basis. Those large changes drive price volatility. In fact, between January 1, 2002 and November 30, 2005, Direct Energy estimates that the historic volatility that small commercial customers using for an average small commercial customer using 45,000 kwh annually would have been 35% if PECO had adopted a monthly pricing mechanism.[5] That volatility was largely driven by the price spikes caused by Hurricanes Katrina and Rita. In addition to a reasonable level of volatility, the small commercial customers would have saved approximately $1.1 billion over that same time period versus the PECO tariff which equates to a

[5] See Appendix III, Intelometry, Inc., Power Price Report, Philadelphia Market (PECO Energy Company), 1-1-02 to 11-30-06, December 2006.

34% reduction off of what they actually paid to PECO during that time frame.[6] In Duquesne's service territory, the same study was conducted for the first 23 months of POLR III service (January 2005 - November 2006). If small commercial customers had procured energy using a monthly priced product in that market, the customers would have seen volatility of 18% and a real reduction in rates of $28 million compared to Duquesne's POLR III rates.[7] In only five of the 23 months analyzed (those near the hurricanes of 2005), customers would have paid rates higher than the current tariff. In the other 18 months, customers would have paid less.

OSBA also believes that longer term contracts may be needed to "enable developers to obtain the funding for alternative energy projects." Direct Energy disagrees with this conclusion and laid out its arguments in its initial Comments in this docket. While Direct Energy would prefer to see a market-based solution to the AEPS supply issues, it has presented a reasonable solution that is competitively neutral below (See Section VI, Page 24).

9. Customers' Comments on Procurement

One customer, United States Steel Corporation ("US Steel"), is suggesting that the DSP should have the ability "to exercise discretion to enter into prudent and reasonable long-term supply contracts." It states that "[a]lthough over-reliance on long-term contracts can be problematic in some circumstances, the use of a long-term contract in a balanced supply portfolio could result in price stability for default service customers." (US Steel Comments at p. 4) US Steel offers no solutions to the circumstance where long-term contracts can be problematic. It also offers no justification for their suggestion other than price stability. US Steel in fact admits, however, that it is already receiving its power from a competitive supplier.

---

6 Intelometry, Inc., Power Price Report, Philadelphia Market (PECO Energy Company), 1-1-02 to 11-30-06, December 2006.

7 Intelometry, Inc., Power Price Report, Pittsburgh Market (Duquesne Light) 1-1-05 to 11-30-06, December 2006.

(US Steel Comments at p.2) That supplier, no doubt, is giving US Steel exactly what it needs in an electricity product.

The Industrial Energy Users of Pennsylvania, *et al* ("IECPA") also argue for a long-term default service price for its members stating that a monthly POLR price is volatile and unpredictable. (IECPA Comments at p.4) IECPA members are procuring power from the competitive markets in Pennsylvania and across the country. They are no strangers to participating in these markets. Presumably, with their size and buying power, they too, are getting exactly the products they are looking for and at very competitive prices. IECPA further argues that a critical business need of the large industrial customers is to manage energy costs. (IECPA Comments at p.4) The entities best suited to help an industrial company manage its costs are the competitive suppliers; perhaps even a supplier that owns generation. These entities are staffed with electricity market experts that can work with their customers on a daily basis to assist in the energy management tasks.

Ironically, IECPA really makes a compelling argument for a monthly default product. It states that the monthly default product "may be a useful **option** for a customer that is in between long-term contracts. Under this scenario, the customer could use the monthly PTC as a bridge between competitive contracts" to bridge timing differences or wait out market anomalies. (IECPA Comments at p. 5, emphasis added) IECPA's description is exactly how the default service is envisioned to work. **Default service is a call option for customers**. It is for customers whose supplier fails to deliver or for customers who fail to choose a supplier. There should not be a free call option on fixed-price energy awaiting the customers who choose to "wait out the market" or fail to sign a contract in a timely manner.

Finally, the views of all of the utilities, OCA and OSBA, and the large industrial customers are in direct contrast to a group representing thousands of smaller customers. Ironically, IECPA argues that it needs long-term fixed price default products to sustain economic growth in the commonwealth. (IECPA Comments at p. 7) The Economic Growth through Competitive Energy Markets Coalition ("CEM") represents 4,000 business electricity consumers "interested in achieving an enhanced competitive electricity market in Pennsylvania." (CEM Comments at p. 1) CEM's first principle is job growth. Its second principle calls for "effective retail energy competition". (CEM Comments at p. 1) CEM specifically "supports the concept of regular adjustment of default service rates." (CEM Comments at p. 2) It is clear that they understand the benefits of effective retail energy competition on their member businesses, and on the overall economy. It appears that IECPA, US Steel and the utilities all have a different agenda.

B. Reconciliation should be eliminated, or alternatively, limited to only reconciling the utilities actual cost to implement its DSP responsibilities, and not include commodity management.

As part of the quarterly-adjusted PTC rate, the Commission would encourage, but not require, interim rate reconciliation to correct under and over-collections. Direct Energy is opposed to such market distorting adjustments. In fact, the suggestion that the DSP would be allowed reconciliation is an admission that the Commission needs to allow the utilities to "correct" prior hedging mistakes. In essence, reconciliations are nothing more than stranded cost recoveries that distort true market price signals significantly. If utilities are unable to effectively manage a supply portfolio, they should not be managing that portfolio. Direct Energy manages an energy portfolio for millions of customers around the world. Reconciliation is not accessible to competitive suppliers, nor should it be part of any competitive energy market framework. It is

a vestige from the bygone era of regulated utilities and is inherently discriminatory and anti-competitive. The Commission must reverse its recommendation to allow reconciliation.

1. PPL and FirstEnergy Comments

Metropolitan Edison, Pennsylvania Electric and Penn Power Companies (collectively "FirstEnergy") and PPL support the Commission's proposal to allow reconciliation. (PPL Comments on Policy Statement at p. 10, FirstEnergy Comments at p. 11) Direct Energy strongly believes that not only is reconciliation of default service rates bad public policy, and perhaps not allowed by the Electric Choice Act it is simply just not necessary.

Reconciliation is bad policy because in very short periods of time, it divorces the market price signals from the true market price of electricity. It will virtually guarantee that customers never see the appropriate price signal from the default service provider. The Commission's ANOFR and Policy Statement make it clear that the Commission would like some meaningful portion of the default service portfolio to include spot market energy purchases. It appears that the Commission believes that with short-term pricing, reconciliation is needed. This is not true. Utilities can, and do, procure default service power in several markets around the country without incurring any risk at all, thereby eliminating the need for a reconciliation mechanism.

PPL suggests that reconciliation is the "only way" that the Electric Choice Act can be implemented fully and that reconciliation is required by the Competition Act. (PPL Comments on Policy Statement at p. 10) This statement is completely without merit. Electric competition is implemented in many markets without any type of reconciliation mechanism.

Most simply, utilities can hold competitive solicitations for load following power supply. With these contracts, no commodity risks are incurred and there is no need for reconciliation of commodity costs. Maryland, for example, is implementing quarterly competitive supply auctions for its mid-size C&I customers (25 kW to 600 kW peak load). These contracts are load

following contracts and the utilities bear no commodity risk by procuring these contracts for their default service (referred to as Standard Offer Service or SOS in Maryland). For residential customers in Maryland, the utilities are procuring a more complex "portfolio" of contracts. Again, all of these contracts are load following, so the utilities bear no commodity exposure. It appears that the Commission has suggested the same type of competitive auction mechanism in Pennsylvania. The utilities should not need a reconciliation mechanism to manage commodity exposure.

Alternatively, if a utility is willing to accept commodity risk, it should do so on its own accord. It should not burden ratepayers with its hedging issues. Duquesne Light has taken this approach in its past POLR cases, is asking for that risk again in its POLR IV case and advocating for being able to manage its commodity risk in this docket as well. Duquesne has not had a reconciliation mechanism in place during its POLR periods, is not proposing reconciliation in POLR IV and is not advocating for it in this docket. In a list of ANOFR issues that Duquesne has commented that it does not concur with, they state "while reconciliation may be recommended, if a utility desires to forgo reconciliation that should be permissible." (Duquesne Comments at p. 25) Apparently, Duquesne is content without reconciliation. We have heard repeatedly about the successes of the Duquesne retail market.

2. Direct Energy Comments

In its initial Comments, Direct Energy urged the Commission to eliminate reconciliation altogether. It argued that the utility should be able to procure power in a risk free manner. Additionally, it argued that a cost adder could be included on top of the energy price. The revenue from the adder would be used to "manage" the default service obligation. Direct Energy fully understands that default service providers incur costs to be the DSP. The initial Comments suggested that the utilities should be forced to manage within the parameters of the cost adders

and that the retail markets would keep their adders in check. If the Commission is not willing to force the utilities to manage their default service operations within a certain cost bandwidth, then Direct Energy would not be opposed to allowing, but not requiring, reconciliation of costs to implement the default service program. In this instance, the price distortions will be very limited (likely less than one-tenth of a cent per kWh per adjustment period). However, if the commission is going to allow reconciliation of costs, it should not allow a profit margin in those costs, because profits should be earned for managing risks. In a world where reconciliation is allowed, the utilities bear no financial risk, so the utilities should not be allowed to earn a return.

II. Competitive Markets Must Include the Availability of Customer Usage and Billing Data in a Readily-Available, Accessible and Usable Format.

Information and data access is vitally important to the long-term success and value of competitive electricity markets. Specifically, as more advanced metering initiatives become available, it will be absolutely critical that competitive market participants have this information available to them on a real-time basis so that all customers can receive the benefits of the advanced metering. But even more important than what is outlined, customers should have portable access to their data so that a customer can log onto a website to authorize the release of its data to a supplier. It should be made available, like cell phone data today, so that a customer need not know his or her account number to access it. A phone number, or Social Security number, or some other reasonable means of identification should be the threshold for data access.

A few parties commented on the Commission's Policy Statement proposals for §69.1812, "Information and data access policies." There does not appear to be any opposition to the concept of availability of customer data. OCA suggested adding a few consumer protections to the data received by any competitive supplier. Direct Energy does not have any opposition to the language suggested by OCA, other than to say that it might not be needed. Electric suppliers are

bound by several consumer protection requirements imposed at the federal and state levels. It is not clear whether incremental regulatory language specific to electric supply information is required.

III. Market Design must Link the Obligation to Bill and Collect with the Entity That "Owns" the Customer.

In the ANOFR, the Commission suggests that full rate unbundling will occur in the near future. The Commission also suggested in its Policy Statement that the "public interest would be served" through the consideration of a Purchase of Receivables ("POR") Program. These two issues are obviously, inextricably linked.

A. OCA Comments on POR

The OCA submits "that any purchase of receivables program must be narrowly tailored to meet the identified problem and must have significant consumer protections, including the requirement that EGS cannot reject any customers and that a customer cannot be terminated for failure to pay amounts that exceed the DSP default rate." Direct Energy does not object to these principles, as long as the entirety of the POR program is competitively neutral. The OCA cites to various settlements on POR-type issues, saying a "purchase of receivables program on top of the established protocol would be unnecessary." (OCA Comments at p. 71) Direct Energy respectfully disagrees with the OCA on this point. The programs cited by the OCA are generally biased against competitive suppliers in that the utility is not fully performing its collections services on their behalf, yet it does so on the behalf of the current POLR suppliers (usually the utilities' unregulated generation affiliates). For example, under the current programs, if an EGS customer fails to pay a competitive supply bill, the debtor is turned over to the EGS, or the EGS is forced to lose the customer, causing its investment in power for that customer to become "stranded" with no right to recover that cost. Yet if that same customer was on POLR service,

the utility would undertake all of its collections activities on behalf of the POLR supplier. This is inherently discriminatory and anti-competitive behavior. The fact that few competitive suppliers take advantage of those provisions should be sufficient evidence that they do not make a comprehensive POR program – similar to that agreed to by Duquesne – unnecessary. Direct Energy is willing to work with the OCA and the Pennsylvania utilities to create an acceptable purchase of receivables agreement. The framework used in the recent Duquesne Light distribution case is a great example and starting point.

B. FirstEnergy Comments on POR

FirstEnergy "believe[s] the endorsement of programs under which EDCs will purchase the receivables of EGSs is not good public policy." (FirstEnergy Comments at p. 13) FirstEnergy states that "[t]he purchase of an EGS's receivables will require diversion of an EDCs capital for purposes not directly related to a primary business activity of the EDC - the reliable delivery of electricity through the distribution system." (FirstEnergy Comments at p. 13) The competitive suppliers and competitive market is not served in any way by having FirstEnergy put the reliable delivery of electricity at risk. The competitive suppliers would never risk such a potentially catastrophic result. However, Direct Energy does not believe that any incremental capital or resources need to be deployed away from the critical reliability function to manage its billing and collections processes.

Today, FirstEnergy performs (as do all of the EDCs) billing and collections services for all of their customers. There is virtually no customer switching in the FirstEnergy service territory. They are also obligated, and presumably stand ready to perform consolidated billing. FirstEnergy, therefore, should not incur any incremental costs as a result of billing and collecting for competitive suppliers. In fact, it is likely that their costs will decrease, because in a competitive market, it is likely that the ultimate cost to consumers will be lower than if they

remain on default service (credit-challenged customers especially will be unlikely to move to a competitive market product unless they see a reduced price). As costs decrease, bad debt expense will decrease. To the extent that some incremental costs are required for programming changes, they should be very minor. In the recent Purchase of Receivables settlement with Duquesne, the suppliers agreed to finance the development of the systems needed to implement the program. It is truly a win-win proposition, as the utility employees are maintained at their current utilization, the competitive market is more efficient, and there will be no duplicative payment of customer service costs to customers that are billed through this program.

As Direct Energy outlined in its initial Comments, the credit and collections relationship should stay with the entity that has the ultimate customer relationship. As an alternative to the EDC performing POR services, Direct Energy would be fully supportive of a model where all customers were billed for all charges (including wires charges) by the competitive supplier, so long as the supplier had all of the collection rights available to it that the wires providers now enjoy. In that scenario, the supplier owns and manages the full customer relationship and bears all risk of non-payment, including non-payment for wires charges.

IV. Market Design must Include Uniform and Consistent Statewide Rules Governing Operational Implementation, Consumer Protection and Compliance Issues, Utility Codes of Conduct for Affiliate Relationships, Retail Market Programs and a Clear Delineation of what are EDC services and what are DSP Services.

The market rules, regulations and standards should be consistent across the state. These include operational protocols and tariffs, consumer protection and compliance issues, codes of conduct for utility and affiliate behavior, retail market programs and a clear delineation of what are EDC services and what are DSP services. On the operational rules side, only two issues seem to be of concern to some entities – switching restrictions and customer referral programs.

A. Switching Restrictions

EAPA supports switching restrictions. The EAPA states that "[a]n absence of switching rules will lead to higher business risks and thus higher electric rates." The short answer is that, as the PUC has already found, switching restrictions that treat customers who switch to a competitive supplier and then return to default service differently than a new customer taking default service for the first time are simply illegal under the Public Utility Code.[8]

Putting aside for a moment the legal bar to such restrictions, the fact that they suggest the absence of such restrictions will lead to higher risks and higher rates is a very compelling argument in support of short-term default supply contracts. EAPA is right in that the long-term contracts bear very costly risks that could be easily eliminated. Regulating them away will not work. The market should manage the risks for the customers. Short-term default service contracts are the means to that end.

The argument from EAPA on switching restrictions is very telling. The concern of the industry is not the **customer and the customers' right to choose a generation provider**. The prevailing concern seems to be to keep the customers under a command and control utility monopoly. Switching restrictions typically render a customer's choice uneconomic, because, if they choose to switch, and the wholesale supplier of DSP electricity needs to be "made whole", the entire economic benefit is foregone. Imagine a world where if you switched from Exxon to Shell because Shell was less expensive or had a better gas formula, that Exxon had the right to charge you for what they "expected you to buy". Interestingly, in the market design promoted by

---

8 Section 2703(e)(4), 66 Pa. C.S. § 2703(e)(4). *Petition of Duquesne Light Company for Approval of Plan for Post-Transition Period Provider of Last Resort Service*, Docket No. P-00032071, Order entered August 23, 2004 at 26-27; *Petition of Duquesne Light Company for Approval of Plan for Post-Transition Period Provider of Last Resort Service Petition for Reconsideration of Duquesne Light Company Petition for Reconsideration of Constellation NewEnergy, Inc. and Constellation Power Source, Inc.*, Docket No. 00032071, Order entered October 5, 2004 at 13-14.

the Commission in the ANOFR where utilities go out for competitive bids for energy, the utilities bear no commodity risk. The risk in this model is borne by the wholesale suppliers.

PECO also supports switching restrictions. PECO states that "if customers are to be offered an annualized fixed-price option, there must be some mechanism in place to protect against 'seasonal gaming.' " (PECO Comments at p. 16) PECO proposes that DSPs should be allowed to impose a 12 month minimum stay on customers or be allowed to charge an exit fee. Again, PECO's suggestion is of questionable legality. Moreover, the answer to this concern is to move markets to shorter term default service and **give customers more choices** in electric supply. PECO recognizes that the switching restrictions are only needed with annual fixed-price products. Therefore, the Commission should order a market responsive default price. PECO's argument is also flawed because under the PECO's recommended competitive auctions, the utilities themselves bear no commodity risk. The utility is a pass-through conduit of electrons.

Customers are unanimously and uniformly opposed to switching restrictions. Richards Energy filed comments on behalf of its 900 commercial and industrial customers explaining in very high detail some of the ludicrous switching restrictions across the Commonwealth. (Richards Energy Comments at p. 1) CEM, another representative of customers in the Commonwealth, "supports provisions of the proposed Policy Statement and Final Rule that prevent restrictions on the ability of customers to move from default service to competitive service through use of such mechanisms as minimum stay provisions and switching fees". (CEM Comments at p. 2) IECPA also supports unencumbered movement between default service and competitive supply service. (IECPA Comments a p. 24)

B. Customer Referral Programs

Duquesne Light has suggested that customer referral programs are bad policy. "Duquesne has concerns that such referral programs do not have ample customer protections and

rely on a "bait and switch" approach, whereby customers get minimal savings for a two month introductory period (less than $3/month) and then are assigned to an unregulated rate not subject to Commission oversight." (Duquesne Comments at p. 25) They also cite a New York State Assemblyman saying that the program is merely a "bait-and-switch game" that lacks transparency. It lacks merit for Duquesne to state that these programs do not have ample customer protections and rely on a bait and switch approach, before such a program has even been formally proposed or presented in Pennsylvania. Direct Energy believes that a customer referral program is one of the most cost-effective and efficient ways to educate customers about retail choice options. If a customer calls the utility call center, the utility educates the customer about alternative energy choices available. The customer does not have to move to a competitive supplier simply because the call was made to the utility. It is the **customer's choice**. The OCA states that a "well designed customer referral programs could be beneficial" to the market. (OCA Comments at p. 72) Such programs have been successful in other states which, presumably, are just as concerned about consumer protections as Pennsylvania.

FirstEnergy believes that customer referral programs "could conflict with the Competitive Safeguards" and urges the Commission to be sure the Competitive Safeguards are not compromised." (FirstEnergy Comments at p. 13) Direct Energy agrees that the Competitive Safeguards must be maintained. Direct Energy does not believe that customer referral programs in any way would compromise the Competitive Safeguards. It goes without saying that any customer choice program (referral or otherwise) needs to be in compliance with the rules and regulations of the Commonwealth.

V. DSP Contracting with Industrial Customers

US Steel suggests that the proposed regulation "must be amended to permit DSPs to enter into long-term negotiated rate contracts with large commercial or industrial customers." (US

Steel Comments at p. 5) IECPA also urges the Commission to allow its members to enter into long-term contacts with the DSP. (IECPA Comments at pp. 18-19) It is not clear why US Steel or IECPA members would want this type of treatment from the DSP. US Steel has offered only one far-flung explanation (and tired refrain) for its request. US Steel suggests that the competitive suppliers would collude and charge US Steel an above market rate in the absence of competitive pressure from the DSP.[9] In markets that are truly competitive, hundreds of suppliers have entered the market – there is no need for competition from the DSP. Even in the retail electric markets in Pennsylvania there are several different suppliers who are anxious to enter into supply arrangements with large retail costumers. If at any time a subset of those suppliers did somehow "collude" to refuse to offer anything but an above market price, there is nothing to stop scores of others from entering the market and providing more attractive prices. It is frankly, outrageous, for US Steel to suggest, without evidence or example of any kind that it needs special treatment because of the theoretical potential that retail electric suppliers can or will engage in price fixing.

In addition, the current DSPs in Pennsylvania do not own generation. Therefore, it would be impossible for them to offer a more competitive rate than "suppliers" – unless they collude with their generation affiliates. In order for the DSP to offer a "better rate," it would need to shift costs and prices around between rate classes and between wires and energy services, in other words they would have to <u>subsidize the large customers</u>. Clearly, that is a bad policy

[9] IECPA makes this same allegation when arguing for a long-term default service. Aside from this behavior being in violation of the anti-trust laws, the argument overlooks one very important fact. The generation companies own the power plants. They are the entities that ultimately set the market prices. They set the prices for default service supply and they set the prices for competitive supply. So the allegation of collusion goes beyond just the competitive suppliers and into the realm of generation suppliers, several of which happen to be affiliates of the current DSPs.

outcome.[10] Some DSPs may be able to procure "below market" cost power from their affiliates (FERC would likely frown on this). If a generation affiliate was willing to sell power at a below-market rate, it should just sell directly to US Steel, without getting the regulated DSP/EDC into the middle of the transaction. Direct sales from generation affiliates to US Steel are completely acceptable behavior. FERC would have no interest or oversight over that transaction. IECPA acknowledges that several DSPs have supply affiliates that could "negotiate[e] a long-term, bi-lateral contract based on the affiliate generator's actual costs may produce the lowest reasonable rates for consumers." (IECPA Comments at p. 18) IECPA and its members are free to negotiate and contract with their generation affiliates. It is just not clear why they need a middleman in the deal. In the absence of a compelling reason to allow the DSP to negotiate directly with an industrial customer (and none has been provided so far), the Commission must not allow that practice. It will either result in no net benefit to the industrial customer, or it will result in **significant financial harm to all other ratepayers**.

VI. AEPS Procurement Does not Need to Confuse the Default Service Issues.

Several entities have presented comments around the topic of having the DSP contract for AEPS assets on a long-term basis. Some support long-term contracts for AEPS resources; others do not.[11] The answer to this question can be easily resolved. If the Commonwealth of Pennsylvania deems it necessary to issue a command and control type edict to have AEPS resources built, then the policies of the Commonwealth should allow the EDC, in its capacity as

---

[10] An economic development subsidy to industrial electric customers may not be a bad policy decision. Direct Energy does not have an opinion on that issue. However, if the decision is made to subsidize electricity prices for a customer, that subsidy should occur on the wires side, or regulated side of the customer's utility bill. The net financial impact would be the same to the industrial company receiving the benefit and to all of those financing the incentive. In addition, the industrial company would have access to all of the benefits that the competitive supply market could bring to it.

[11] See Comments of PPM, PennFutures, PV Now and the Mid-Atlantic Solar Energy Industry Association, OCA and Direct Energy.

EDC (not DSP), to procure the AEPS assets required based on the aggregate load requirements for the territory. The EDC can then sell off all of what it procured for the year to the DSP and to all competitive suppliers serving in the market. It would sell the AEPS resource to the market at actual cost, on a per unit basis, equally to all market participants. This should resolve the debate, eliminating any risk of stranded cost and being perfectly competitively neutral while, at the same time, financing AEPS assets. Direct Energy does not believe a market distortion like this is needed. Fundamentally, Direct Energy believes that under the appropriate regulatory mechanism, AEPS assets will be built, financed and consumed by market participants. In the absence of that belief, Direct Energy's proposed solution should resolve the AEPS market issues.

VII. Other Issues

A. Duquesne's ability to conduct default RFPs

In support of its bilaterally procured energy, Duquesne stated that it is "concerned that repeated attempts to conduct RFPs limited to its service area have not produced a sufficient pool of bidders to establish a viable competitive wholesale market." (Duquesne Comments at p. 6) Duquesne sits in the middle of PJM, arguably the most robust wholesale market in the country. Duquesne should have no problem procuring power in a competitive bid process. The wholesale auctions that Duquesne refers to in its comments were for fixed price default service for a very small number of large business customers. This is a very risky product, and not one for which many suppliers choose to bid. It is largely this reason that the **wholesale** community largely supports hourly pricing for these large customers. Most certainly, a wholesale bid for smaller commercial and residential customers would produce satisfactory, competitive results.

B. EDC as "Last Resort"

PPL supports the EDC being named as the DSP. In support, it says that "as a practical matter, the incumbent EDC will remain the "last resort" DSP if an alternative DSP defaults on its

obligations". (PPL Comments at p. 6) The distinction between the EDC and the DSP will become more clear as the Pennsylvania retail market develops. PPL's statement is patently untrue. There need not be any obligation on a wires company to "stand ready" to be a default service provider. In Texas, where the market has truly deregulated, the market participants are the default service providers around the state. Competitive entities, not affiliated with any Texas utilities stand ready to serve customers in the event of a default, or if a customer chooses to be on default supply. Wires companies do not fill that role.

C. Direct assignment of contracts

One of the fundamental premises of restructuring is placing risk where risk belongs – on the shareholders and management – and removing it from the ratepayers. UGI proposes an outrageous concept where it would be allowed to direct assign its "out of the money" contracts to a retail supplier. Alternatively, UGI suggests that it should be able to recover its default supply **"stranded costs"** through a distribution rate recovery mechanism. UGI should be prohibited from recovering any default supply costs as stranded costs. Utilities around the country manage default service in a completely risk-free manner. UGI is allowed to manage its default obligations in a risk-free manner in Pennsylvania. If it chooses to take on supply risk in a competitive market, it must be forced to bear that risk in a competitive manner. Its shareholders win, or its shareholders lose. UGI should be absolutely prohibited from moving its losses to ratepayers or competitive suppliers serving customers in its territory. To minimize UGI's exposure, its customers should be on a market-reflective default service.

D. Generation Development

The OCA, in arguing against short-term default contracts, claims that "the short term focus also does not seem designed to ensure reliable supply, and the development of new resources." (OCA Comments at p. 10) Reliability and generation development are very

complex issues. <u>Not one entity, other than the OCA, has raised reliability or generation development (outside of the AEPS issues) as a concern with short-term contracts</u>. While all entities in the market are responsible for reliable operations and behavior on the system, "reliability" is largely a wires responsibility. The EDCs ensure reliable delivery of power at the distribution level. The ISOs (PJM, MISO and NYISO) are responsible for transmission reliability. Generation reliability is largely managed by the market and the ISOs. In fact, PJM and its members have been arguing for years that ICAP (soon to convert to RPM) guarantees reliability and incentivizes generation development. OCA has supported PJM in those arguments historically, so must believe that reliability is secure and will not be threatened by short-term default contracts. Additionally, if the OCA believes that customers want long-term stable prices, they will enter into an agreement with a competitive supplier to provide them. Suppliers will then enter into agreements with generators to provide the power. Those contracts should provide the same incentive to build power plants as the DSP contracts would. The allegation that short-term contracts put system reliability at risk is completely unsupported.

VIII. Conclusion

Generally, it appears the market participants fully support the continued development of the competitive retail markets.

There are a few fundamental differences among the stakeholders that the Commission must resolve. It is Direct Energy's opinion that the Default Service rates must be market-reflective in order to facilitate robust competitive retail alternatives. Customer information must be readily available and usable. A competitively neutral billing and collections mechanism must be implemented and rules, tariffs, protocols, etc. should be consistent across the Commonwealth and must be conducive to competitive markets and not limit customer choices. It appears that

only a few minor objections have been raised to the customer information, customer billing and operational issues.

However, a wide divide exists on the definition of "prevailing market price" and the implementation tactics of default supply procurement. The Commission must push Default Service to a more market-reflective service.

Respectfully submitted,

Frank Lacey
Director, Government and Regulatory Affairs
Direct Energy Services, LLC
42 Lintel Drive
McMurray, PA 15317
(724) 941-2149
Frank.lacey@directenergy.com

Dated: March 23, 2007

APPENDIX I

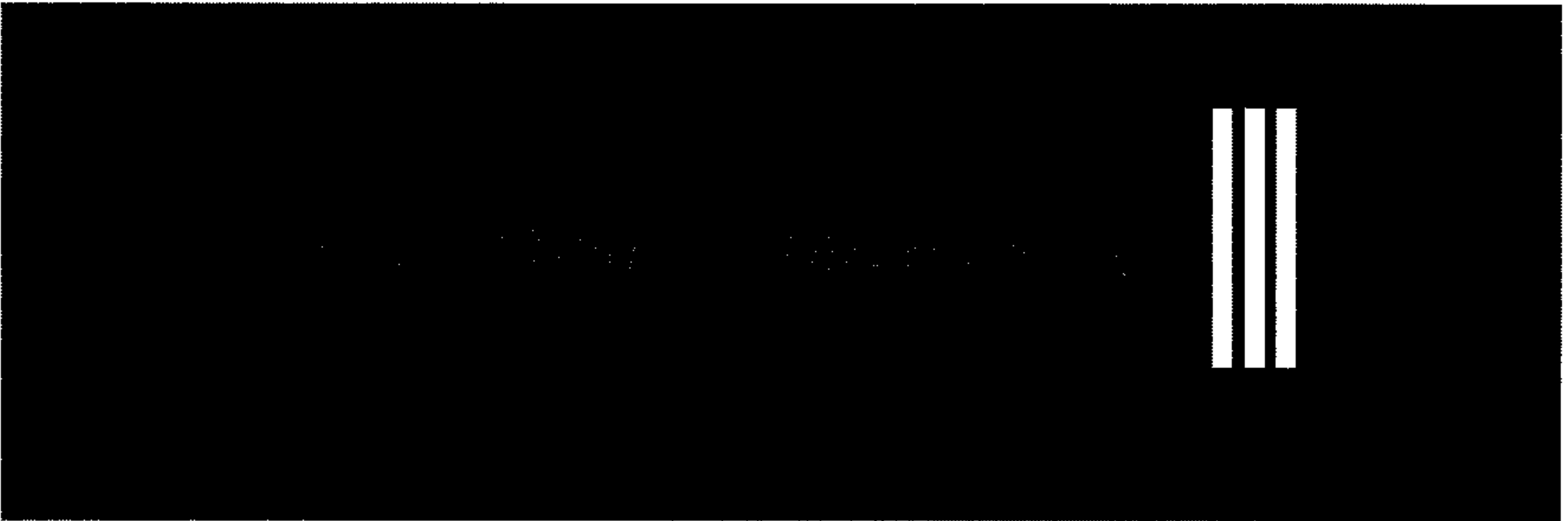
Average Rate Schedule RS -- Energy and Capacity Charges for 2006
Based on 1,000 kWh per month

	Cents/kWh DAK Adjustment	Cents/kWh Tariff Generation Price
Average Energy and Capacity Charge for 2006	5.03	6.27
Less Gross Receipts Tax 5.9%	0.28	0.35
	4.75	5.92
Less Capacity of 0.58 cents/kWh	0.58	0.58
	4.17	5.34
Less Losses @ 9%	0.34	0.44
	3.83	4.90
Less Load Following Factor of 1.13	0.44	0.56
Market Price for Energy (LMP Proxy)	3.39	4.34

Based on DAK-3, LMP purchasing would have resulted in savings in 65% (32 out of 49) of months

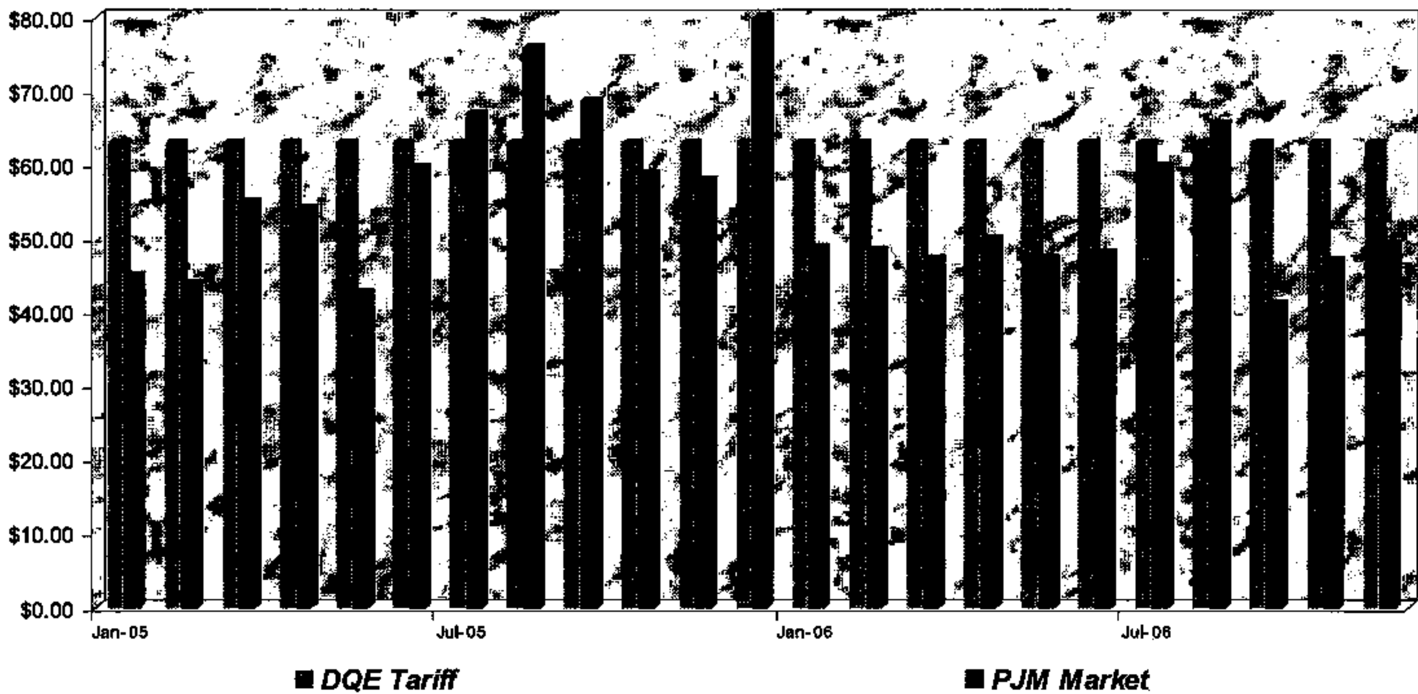
Date	LMP Price	Tariff Generation Price	LMP Savings or Losses	
Dec-01	1.97	4.34	savings	
Jan-02	2.05	4.34	savings	
Feb-02	2.02	4.34	savings	
Mar-02	2.44	4.34	savings	
Apr-02	2.73	4.34	savings	
May-02	2.22	4.34	savings	
Jun-02	2.72	4.34	savings	
Jul-02	3.64	4.34	savings	
Aug-02	3.68	4.34	savings	
Sep-02	2.56	4.34	savings	
Oct-02	2.75	4.34	savings	
Nov-02	2.29	4.34	savings	
Dec-02	3.21	4.34	savings	
Jan-03	4.75	4.34	loss	
Feb-03	4.75	4.34	loss	
Mar-03	5.27	4.34	loss	
Apr-03	3.60	4.34	savings	
May-03	3.06	4.34	savings	
Jun-03	2.88	4.34	savings	
Jul-03	4.03	4.34	savings	
Aug-03	3.88	4.34	savings	
Sep-03	3.07	4.34	savings	
Oct-03	2.89	4.34	savings	
Nov-03	2.96	4.34	savings	
Dec-03	3.64	4.34	savings	
Jan-04	5.54	4.34	loss	
Feb-04	4.19	4.34	savings	
Mar-04	3.95	4.34	savings	
Apr-04	4.31	4.34	savings	
May-04	4.85	4.34	loss	
Jun-04	3.80	4.34	savings	
Jul-04	4.27	4.34	savings	
Aug-04	3.88	4.34	savings	
Sep-04	4.19	4.34	savings	
Oct-04	3.95	4.34	savings	
Nov-04	3.74	4.34	savings	
Dec-04	4.65	4.34	loss	
Jan-05	5.39	4.34	loss	
Feb-05	4.49	4.34	loss	
Mar-05	5.25	4.34	loss	
Apr-05	4.45	4.34	loss	
May-05	4.29	4.34	savings	
Jun-05	5.64	4.34	loss	
Jul-05	6.90	4.34	loss	
Aug-05	8.70	4.34	loss	
Sep-05	8.04	4.34	loss	
Oct-05	8.02	4.34	loss	
Nov-05	6.03	4.34	loss	
Dec-05	8.23	4.34	loss	
Months of LMP savings vs. Tariff			32	65%
Months of LMP loss vs. Tariff			17	35%
Total Months			49	100%

APPENDIX II

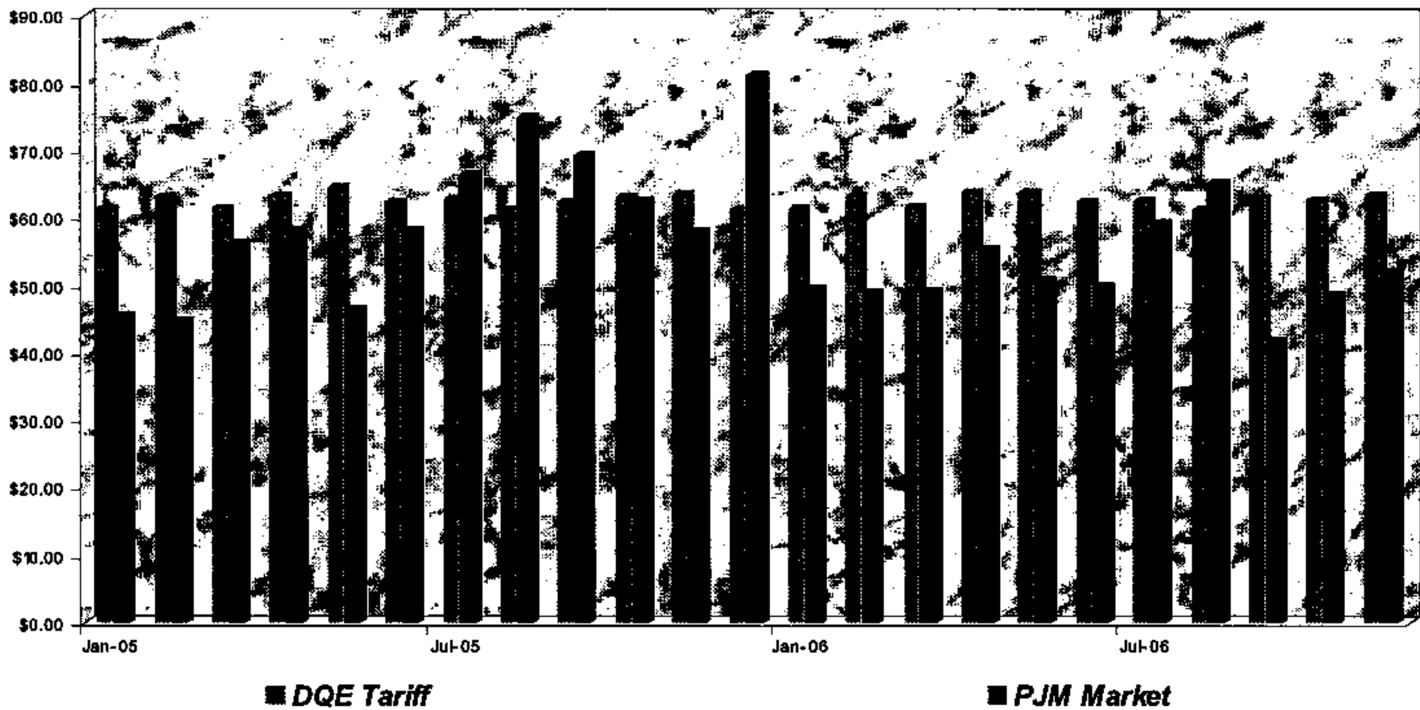


Pittsburgh Market (Duquesne Light) - 1/1/2005 – 11/30/2006

DQE Analysis - Residential



DQE Analysis - Small Commercial



Residential Class Total Cost
Tariff v Market

Estimated Residential Class Generation Service Cost (Total $)

Price Period	Approximate Number of DQE Rate RS Customers	Estimated Generation Service Tariff Cost for Residential Class	Estimated Generation Service Market Cost for Residential Class	Delta
Jan-05	496,926	$34,620,071	$24,746,668	$9,874,403
Feb 05	496,926	$30,147,022	$20,999,078	$9,147,944
Mar-05	496,926	$31,439,064	$27,402,336	$4,036,710
Apr-05	496,926	$23,108,801	$19,824,766	$3,284,035
May 05	496,926	$21,301,099	$14,434,386	$6,866,713
Jun 05	496,926	$29,345,909	$27,811,193	$1,534,716
Jul-05	496,926	$34,871,682	$37,116,301	($2,244,619)
Aug-05	496,926	$33,369,339	$40,268,675	($6,899,335)
Sep 05	496,926	$23,197,407	$25,278,788	($2,081,381)
Oct-05	496,926	$21,920,314	$20,447,427	$1,472,886
Nov-05	496,926	$25,607,739	$23,603,147	$2,004,593
Dec-05	496,926	$35,530,732	$45,084,630	($9,553,897)
Jan 06	496,926	$34,910,346	$27,033,871	$7,876,475
Feb-06	496,926	$30,199,453	$23,200,319	$6,999,134
Mar-06	496,926	$31,079,066	$23,293,743	$7,785,322
Apr-06	496,926	$23,147,173	$18,294,623	$4,852,550
May 06	496,926	$21,069,406	$16,826,791	$5,243,616
Jun-06	496,926	$29,001,972	$22,744,881	$7,067,091
Jul-06	496,926	$35,236,942	$33,471,078	$1,765,864
Aug-06	496,926	$32,940,517	$34,362,842	($1,422,326)
Sep 06	496,926	$23,028,983	$16,024,981	$8,004,002
Oct-06	496,926	$22,045,387	$16,438,642	$6,606,746
Nov-06	496,926	$25,980,551	$20,333,139	$5,647,511
Total for Analysis Period		$653,979,066	$577,040,304	**$76,938,761**

*The number of customers figures were obtained from DQE's 4th quarter of 2005 FERC FORM 1.

Small Commercial Class Total Cost Tariff v Market

Estimated Small Commercial Class Generation Service Cost (Total $)
DQE Tariff v PJM Market

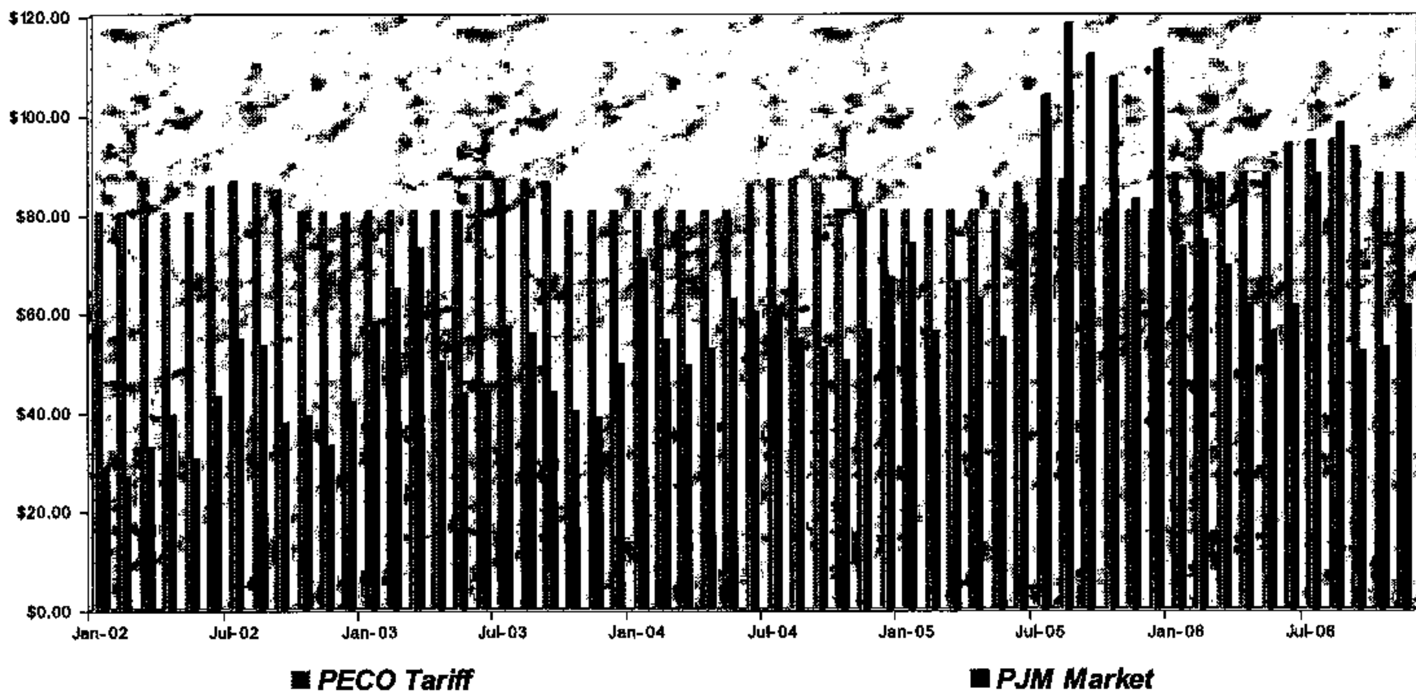
Price Period	Approximate Number of DQE Rate GS/GM Customers	Estimated Generation Service Tariff Cost for Small Commercial Class	Estimated Generation Service Market Cost for Small Commercial Class	Delta
Jan-05	54,628	$12,506,172	$9,264,243	$3,241,929
Feb-05	54,628	$11,690,119	$8,286,781	$3,403,338
Mar-05	54,628	$12,337,315	$11,201,071	$1,066,744
Apr-05	54,628	$11,703,245	$10,786,975	$916,270
May-05	54,628	$12,236,720	$8,792,344	$3,444,376
Jun-05	54,628	$13,857,155	$12,931,169	$926,986
Jul-05	54,628	$14,184,112	$15,009,778	($825,666)
Aug-05	54,628	$14,317,688	$17,573,999	($3,256,311)
Sep-05	54,628	$13,081,150	$14,522,046	($1,440,896)
Oct-05	54,628	$12,692,241	$12,600,464	$91,777
Nov-05	54,628	$12,288,007	$11,214,012	$1,073,995
Dec-05	54,628	$12,706,112	$16,849,894	($4,143,782)
Jan-06	54,628	$12,532,870	$10,093,176	$2,439,694
Feb-06	54,628	$11,680,028	$9,020,168	$2,659,860
Mar-06	54,628	$12,303,586	$9,796,515	$2,507,071
Apr-06	54,628	$11,605,449	$10,065,076	$1,540,372
May-06	54,628	$12,371,628	$9,815,836	$2,555,792
Jun-06	54,628	$13,062,814	$11,072,718	$2,790,096
Jul-06	54,628	$14,245,606	$13,497,074	$748,531
Aug-06	54,628	$14,299,904	$15,247,014	($947,111)
Sep-06	54,628	$12,960,651	$8,603,242	$4,357,409
Oct-06	54,628	$12,787,912	$9,912,528	$2,875,384
Nov-06	54,628	$12,310,192	$10,074,443	$2,235,749
Total for Analysis Period		$294,561,474	$266,311,866	**$28,249,608**

* The number of customers figures were obtained from DQE's 4th quarter of 2005 FERC FORM 1.

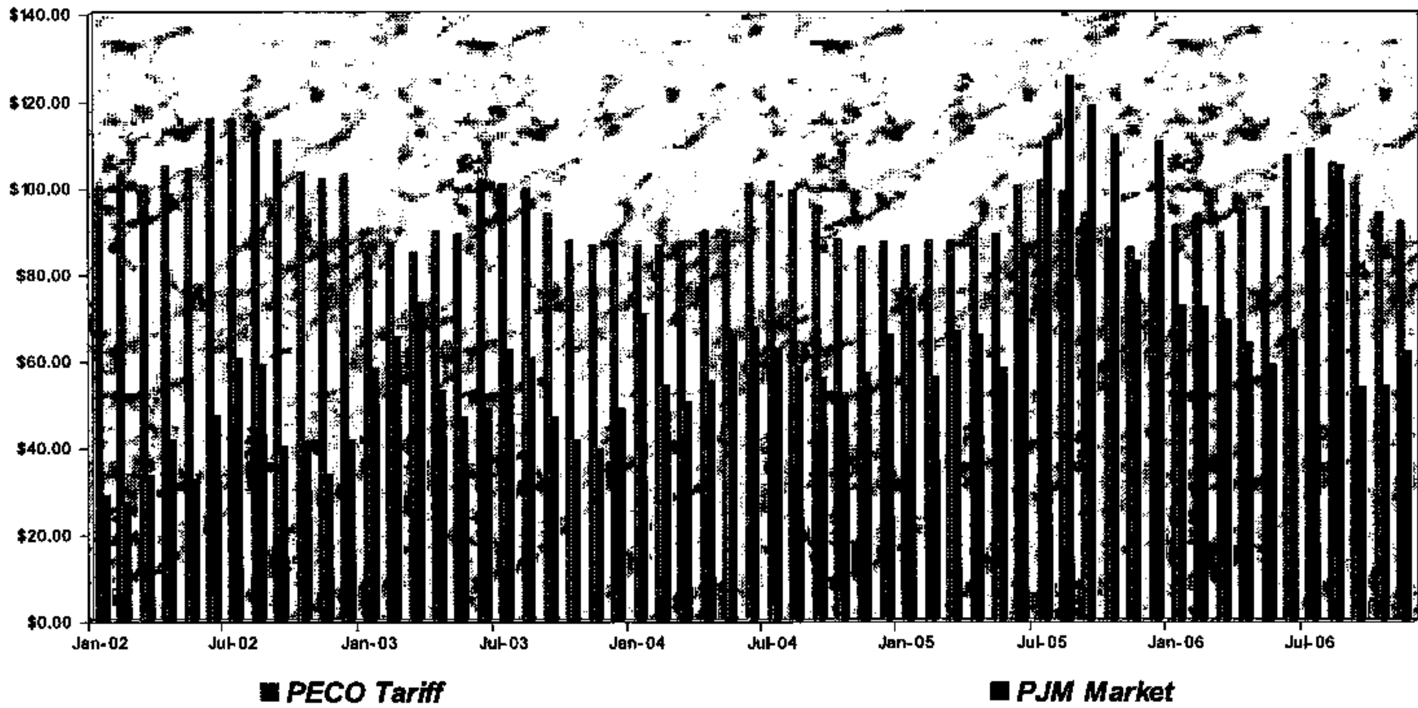
APPENDIX III

Philadelphia Market (PECO Energy Company) - 1/1/2002 – 11/30/2006

PECO Analysis - Residential



PECO Analysis - Small Commercial



Residential Class Total Cost
Tariff v Market

[illegible]

Price Period	Approximate Number of PECO Residential Customers*	Estimated Generation Service Tariff Cost for Residential Class	Estimated Generation Service Market Cost for Residential Class	Delta
Jan-02	1,216,010	$90,211,954	$31,801,251	$58,410,703
Feb-02	1,216,010	$77,862,999	$26,138,306	$51,724,693
Mar-02	[illegible]	[illegible]	[illegible]	[illegible]
Apr-02	[illegible]	[illegible]	[illegible]	[illegible]
May-02	1,216,010	$70,243,661	$20,005,500	$47,330,193
Jun-02	[illegible]	[illegible]	[illegible]	[illegible]
Jul-02	[illegible]	[illegible]	[illegible]	[illegible]
Aug-02	1,216,010	$120,002,237	$70,023,186	$49,169,051
Sep-02	[illegible]	[illegible]	[illegible]	[illegible]
Oct-02	[illegible]	[illegible]	[illegible]	[illegible]
Nov-02	1,216,010	$75,603,674	$31,523,663	$44,179,001
Dec-02	[illegible]	[illegible]	[illegible]	[illegible]
Jan-03	[illegible]	[illegible]	[illegible]	[illegible]
Feb-03	1,225,055	$70,610,756	$60,879,922	$10,330,675
Mar-03	[illegible]	$85,453,990	$77,517,666	$7,936,324
Apr-03	[illegible]	[illegible]	[illegible]	[illegible]
May-03	1,225,055	$77,250,732	$41,956,235	$35,292,497
Jun-03	[illegible]	$105,114,140	$54,338,000	$50,776,140
Jul-03	[illegible]	[illegible]	[illegible]	[illegible]
Aug-03	1,225,055	$130,421,700	$84,049,636	$46,372,127
Sep-03	[illegible]	$106,830,460	$54,818,687	$52,011,773
Oct-03	[illegible]	[illegible]	[illegible]	[illegible]
Nov-03	1,225,055	$77,110,431	$57,000,316	$19,100,117
Dec-03	[illegible]	$83,200,461	$61,337,760	$21,862,701
Jan-04	[illegible]	[illegible]	[illegible]	[illegible]
Feb-04	1,235,276	$82,107,060	$50,000,626	$29,761,913
Mar-04	[illegible]	$86,380,621	$52,320,083	$33,040,499
Apr-04	[illegible]	[illegible]	[illegible]	[illegible]
May-04	1,235,276	$77,096,621	$60,033,001	$17,063,620
Jun-04	[illegible]	$108,669,322	$76,063,846	$32,480,476
Jul-04	[illegible]	[illegible]	[illegible]	[illegible]
Aug-04	1,235,276	$102,001,093	$90,027,470	$12,171,627
Sep-04	[illegible]	$104,462,475	$84,599,734	$20,063,741
Oct-04	[illegible]	[illegible]	[illegible]	[illegible]
Nov-04	1,235,276	$77,400,700	$54,297,800	$23,107,900
Dec-04	1,235,276	$95,076,514	$80,932,914	$14,143,600
Jan-05	[illegible]	[illegible]	[illegible]	[illegible]
Feb-05	1,240,144	$79,610,242	$55,504,004	$24,106,240
Mar-05	1,240,144	$85,351,495	$69,061,129	$16,417,366
Apr-05	[illegible]	[illegible]	[illegible]	[illegible]
May-05	1,240,144	$70,624,406	$53,600,044	$24,024,132
Jun-05	1,240,144	$110,419,388	$105,187,063	$5,232,325
Jul-05	[illegible]	[illegible]	[illegible]	[illegible]
Aug-05	1,240,144	$136,131,078	$154,228,838	($18,097,760)
Sep-05	1,240,144	$102,101,871	$133,919,922	($31,817,051)
Oct-05	[illegible]	[illegible]	[illegible]	[illegible]
Nov-05	1,240,144	$77,686,608	$79,863,746	($2,277,106)
Dec-05	1,240,144	$84,380,537	$118,591,354	($34,210,817)
Jan-06	[illegible]	[illegible]	[illegible]	[illegible]
Feb-06	1,247,000	$87,660,644	$74,099,883	$13,471,761
Mar-06	1,247,988	$99,586,997	$79,759,087	$19,827,240
Apr-06	[illegible]	[illegible]	[illegible]	[illegible]
May-06	1,247,000	$86,313,378	$60,179,716	$21,133,662
Jun-06	1,247,988	$122,762,691	$80,098,569	$42,663,921
Jul-06	[illegible]	[illegible]	[illegible]	[illegible]
Aug-06	1,247,000	$148,204,803	$160,003,396	($5,798,446)
Sep-06	1,247,988	$110,821,069	$62,012,266	$48,808,829
Oct-06	[illegible]	[illegible]	[illegible]	[illegible]
Nov-06	1,247,000	$80,410,704	$58,618,300	$20,828,404
Total for Analysis Period		$5,640,766,231	$4,114,541,256	$1,526,225,976

* The number of customers figures were obtained from PECO's FERC Form 1. Number of customers for 2006 were estimated by growing 2005 customer counts by the average percentage change in number of customers year over year for the analysis period.

LMP Commercial Class Total Cost
Tariff v Market

Price Period	Approximate Number of PECO Commercial Customers	Estimated Generation Service Tariff Cost for Commercial Class	Estimated Generation Service Market Cost for Commercial Class	Delta
Jan-02	150,971	$50,432,880	$10,107,007	$40,325,383
Feb-02	150,971	$51,205,039	$13,404,060	$37,790,979
Mar-02	150,971	$53,743,576	$17,765,072	$35,978,504
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Jun-02	150,971	$71,320,305	$59,005,200	$12,315,105
Jul-02	150,971	$70,980,761	$41,880,789	$38,508,992
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Oct-02	150,971	$55,166,170	$21,001,400	$35,166,760
Nov-02	150,971	$52,140,885	$17,286,252	$34,853,630
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Feb-03	151,246	$43,232,210	$32,454,100	$10,778,000
Mar-03	151,246	$46,054,158	$40,819,236	$5,234,922
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Jun-03	151,246	$50,041,037	$29,373,050	$20,667,987
Jul-03	151,246	$39,050,039	$12,767,210	$26,283,422
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Oct-03	151,246	$47,367,000	$22,495,913	$24,871,087
Nov-03	151,246	$43,077,106	$10,030,553	$33,046,553
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Feb-04	152,069	$44,327,636	$27,720,162	$16,607,466
Mar-04	152,069	$40,061,551	$27,071,727	$20,300,223
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Jun-04	152,069	$61,890,020	$41,526,306	$20,364,714
Jul-04	152,069	$60,079,407	$42,056,462	$20,021,034
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Oct-04	152,069	$46,860,564	$27,981,261	$18,879,303
Nov-04	152,069	$44,433,777	$25,392,710	$19,041,067
Dec-04	152,069	$48,316,751	$36,553,721	$11,762,031
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Feb-05	153,012	$43,846,370	$33,113,636	$10,726,730
Mar-05	153,012	$46,400,766	$35,000,763	$11,400,003
Apr-05	153,012	$46,058,889	$34,281,114	$11,777,775
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Jul-05	153,012	$68,760,634	$73,921,943	($5,161,309)
Aug-05	153,012	$67,646,258	$83,889,303	($16,243,045)
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Nov-05	153,012	$44,743,121	$43,089,127	$1,654,994
Dec-05	153,012	$49,294,209	$61,342,607	($12,048,398)
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Mar-06	153,600	$40,741,095	$30,330,668	$10,410,427
Apr-06	153,600	$49,094,718	$32,159,685	$16,935,033
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Jul-06	153,600	$73,703,061	$62,801,312	$10,901,750
Aug-06	153,600	$72,001,302	$71,002,400	$998,922
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Nov-06	153,600	$48,032,850	$32,999,139	$15,033,711
Total for Analysis Period		$3,230,807,662	$2,130,320,670	$1,101,687,085

* The number of customers figures were obtained from PECO's FERC Form 1. Number of customers for 2006 were estimated by growing 2005 customer counts by the average percentage change in number of customers year over year for the analysis period.