PECO ENERGY COMPANY
STATEMENT NO. 9-R

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA PUBLIC UTILITY COMMISSION

v.

PECO ENERGY COMPANY – ELECTRIC DIVISION

DOCKET NO. R-2010-2161575

REBUTTAL TESTIMONY

WITNESS: ALAN B. COHN

SUBJECTS: UNBUNDLING UNCOLLECTIBLE ACCOUNTS EXPENSE; INCOME TAXES; RATE DESIGN AND REVENUE ALLOCATION

DATED: AUGUST 3, 2010

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REBUTTAL TESTIMONY
OF
ALAN B. COHN

I. INTRODUCTION AND PURPOSE OF TESTIMONY

1. Q. **Please state your full name and business address.**

A. My name is Alan B. Cohn. My business address is PECO Energy Company, 2301 Market Street, Philadelphia, Pennsylvania 19103.

2. Q. **By whom are you employed and in what capacity?**

A. I am employed by PECO Energy Company ("PECO" or the "Company") as Manager of Revenue Analysis in the Regulatory Group.

3. Q. **Have you testified previously in this proceeding?**

A. Yes, I submitted direct testimony that is marked as PECO Statement No. 9. My background and qualifications are set forth in that statement.

4. Q. **What is the purpose of your rebuttal testimony?**

A. My rebuttal testimony will address six separate areas:

First, I will respond to the direct testimony of Ms. Dorothy Morrissey on behalf of the Office of Trial Staff ("OTS") with regard to her proposal to "unbundle" uncollectible accounts expense related to electric generation supply revenues.

Second, I will respond to the direct testimony of Mr. David J. Effron on behalf of the Office of Consumer Advocate ("OCA") concerning the ratemaking treatment of a possible future change in the method of tax accounting that PECO employs to determine the portion of expenditures that are capitalized and depreciated versus deducted on a current basis for federal income tax purposes.

Third, I will respond to Mr. Clarence L. Johnson on behalf of the OCA, Mr. Stephen Buckley on behalf of the City of Philadelphia ("City"), Mr. Leo Smith on behalf of Stanley Stubbe and Messrs. Stephen J. Baron and James S. Schneider on behalf of the Philadelphia Area Industrial Energy Users Group ("PAIEUG") concerning rate design issues.

Fourth, I will respond to Mr. Johnson, Mr. Baron, Mr. Brian Kalcic on behalf of the Office of Small Business Advocate ("OSBA") and Mr. James T. Selecky on behalf of the Commercial Group concerning the allocation of the Company's proposed revenue increase among customer classes.

Fifth, I will respond to Mr. Johnson's testimony concerning the Company's proposal to recover legacy meter costs as a component of its Smart Meter cost recovery charge.

The sixth and seventh areas covered in my rebuttal testimony update the Company's cost-recovery proposals for Smart Meter technology and for certain administrative cost elements of default service, respectively.

5. Q. Are you submitting any exhibits with your rebuttal testimony?

A. Yes, I am sponsoring six exhibits, which are discussed hereafter, that consist of the following:

Exhibit ABC-1R	Tariff Page (Street Lighting)
Exhibit ABC-2R	Tariff Page (Energy Efficiency and Conservation Program Charge)
Exhibit ABC-3R	Large Interruptible Load Rider Total Bill Increase
Exhibit ABC-4R	Kimberly Clark – Estimate Of Total Bill
Exhibit ABC-5R	Comparison Of Proposed Alternative Revenue Allocations
Exhibit ABC-6R	Update To Exhibit ABC-14

II. UNBUNDLING OF ELECTRIC SUPPLY UNCOLLECTIBLE ACCOUNTS EXPENSE

6. Q. **Briefly describe Ms. Morrissey's proposal concerning uncollectible accounts expense.**

A. Ms. Morrissey agrees with the overall level of uncollectible accounts expense claimed by the Company. However, she proposes "unbundling" uncollectible accounts expense related to default service generation supply revenues by removing that expense from the Company's distribution rates and having the Company recover it through a so-called "Merchant Function Charge" or "MFC." Although Ms. Morrissey does not say so explicitly, it appears from her testimony that the MFC would be: (1) a separate adjustment clause; (2) established under Section 1307 of the Public Utility Code; (3) recalculated periodically; and (4) by-passable, i.e., charged only to customers that purchase electric supply from the Company. It is not clear from Ms. Morrissey's testimony if the MFC would be reconcilable, although, as a Section 1307 clause, reconciliation may be required.

7. Q. **What is Ms. Morrissey's purported rationale for her proposal?**

A. Ms. Morrissey contends that unbundling uncollectible accounts expense related to electric generation supply revenue would "support establishing a more optimal competitive market by reflecting the true costs of electric supply in the Company's price to compare."

8. Q. Do you agree with Ms. Morrissey's contention that removing electric generation supply uncollectible accounts expense from distribution rates is necessary to enhance competition?

A. No, I do not, because the Company has already taken a major step to enhance competition by adopting an electric purchase of receivables program under which it will purchase electric generation suppliers' ("EGSs") accounts receivable at no discount from face value for uncollectible accounts expense,[1] which EGSs have stated will materially enhance competition in PECO's service territory. As part of this program, the Company will recover all uncollectible accounts expense, whether derived from accounts purchased from EGSs or from customers receiving default service, through its distribution rates. Consequently, as part of that program, the very same issue raised by Ms. Morrissey has been addressed in a manner that provides a better resolution than Ms. Morrissey's proposal. In fact, EGSs expressed a strong preference for the Company's approach, namely, purchasing receivables at no discount for uncollectible accounts and recovering all uncollectible accounts expense in base rates, over the approach proposed by Ms. Morrissey.

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[1] Under PECO's electric purchase of receivables program, there is an initial, temporary discount on purchased receivables, which is for the sole purpose of recovering the initial implementation costs of the program. *Petition Of PECO Electric Company For Approval Of Its Revised Electric Purchase Of Receivables Program*, Docket No. P-2009-2143607 (June 18, 2010) (p. 37).

9. Q. Please explain the relevant provisions of PECO's EGS purchase of receivables program.

A. On November 20, 2009, the Company filed a Petition seeking PUC approval of a revised EGS purchase of receivables ("Electric POR") program, which was docketed as P-2009-2143607. Various parties participated in the ensuing proceeding including the OTS, OCA, OSBA and several major EGSs.

As I previously explained, as part of its Electric POR program, the Company proposed to continue to recover **all** uncollectible accounts expense through its distribution rates because, as the purchaser of receivables from participating EGSs, PECO will bear the cost of uncollectible accounts for **all** customers, whether they purchase default service from the Company or purchase generation from an EGS. Specifically, PECO will bear the uncollectible accounts expenses of default customers, just as it does now. Additionally, because it will purchase accounts receivable from EGSs at face value without a discount for uncollectible accounts, it will bear the uncollectible accounts expense associated with the purchased receivables as well. Consequently, EGSs will not be placed at a competitive disadvantage under the Company's approach because, by PECO bearing all uncollectible accounts expense and recovering that expense in its distribution rates, both EGSs' prices for generation and PECO's price to compare will be set forth on a comparable basis, which excludes the cost of uncollectible accounts expense. The competitive neutrality of the Company's Electric POR program and the associated recovery of all uncollectible accounts expense in distribution rates is evidenced by the fact that all EGSs that participated in the Electric POR proceeding supported the

Company's proposal. Moreover, since uncollectible accounts expense as a percent of revenue does not vary based on whether a customer buys electricity from PECO or an EGS, recovering an overall average rate of uncollectible accounts expense from all customers through distribution rates does not disproportionately burden or benefit any customer group.

In the Electric POR proceeding, a settlement was reached with all parties except the OTS, subject to the reservation for litigation of an issue that is not relevant to the issue discussed here. In that proceeding, the OTS advocated the same position Ms. Morrissey is proposing here, namely, "unbundling" default service generation uncollectible accounts expense and recovering it in a separate, by-passable charge. As I previously indicated, all parties, including the EGSs, opposed the OTS' proposal.

In its June 18, 2010 final Order (p. 48) approving PECO's Electric POR program, the Commission rejected the OTS' position and approved PECO's proposal to continue to recover electric uncollectible accounts expense as part of electric distribution rates and stated: "Based upon the discussion above, we shall adopt PECO's proposal to include the entirety of uncollectible accounts expense within its distribution service base rates." In short, the proposal being advanced by Ms. Morrissey in this case has already been rejected by the Commission in PECO's Electric POR proceeding.

10. Q. What would the consequences be if Ms. Morrissey's proposal were adopted?

A. It is not clear what those consequences might be because Ms. Morrissey did not discuss how, if at all, her proposal would work in conjunction with the Company's Commission-approved Electric POR program. For example, does Ms. Morrissey assume that the Company would continue to purchase EGS accounts receivable without a discount for uncollectible accounts expense? If so, the Company would need some mechanism to recover the uncollectible accounts expense associated with the purchased receivables. Presumably, Ms. Morrissey, who advocates "unbundling" all uncollectible accounts expense from distributions rates, would not support recovering the uncollectible accounts expense associated with purchased receivables in distribution rates. But, with no alternative vehicle for recovery, PECO would be forced to bear that cost without compensation, which is neither lawful nor fair.

Alternatively, PECO would have to cease purchasing EGSs' accounts receivable at face value and, instead, impose a discount to recover uncollectible accounts expense. However, EGSs have already expressed their opposition to this approach, which would eliminate much of the pro-competitive effect of the Company's Electric POR program – not to mention substantially depart from the terms of the program approved by the Commission in June of this year.

Conceivably, PECO could implement Ms. Morrissey's proposal, continue to purchase EGSs' accounts receivable at face value without a discount for uncollectible accounts expense, and recover all uncollectible accounts expense (both the expense arising from default service and the expense associated with purchased receivables) through the MFC. In that case, the MFC would be excluded from the price to compare. However, the end result of that approach is identical to keeping all uncollectible accounts expense in distribution rates, except that there would be needless administrative time, resources and costs associated with establishing, changing and reconciling the MFC, and the possibility of customer confusion would be increased significantly.

In summary, it would be very difficult to meld Ms. Morrissey's proposal with the Company's existing Electric POR program in a way that is lawful, adequately compensates PECO for the uncollectible accounts expense it would incur and preserves the pro-competitive effects of the Electric POR program. Accordingly, Ms. Morrissey's proposal should be rejected.

III. RATEMAKING EFFECTS OF A POSSIBLE CHANGE IN METHOD OF TAX ACCOUNTING

11. Q. Briefly describe Mr. Effron's proposal concerning the ratemaking consequences of a possible change in tax accounting methodology.

A. Mr. Effron is anticipating that PECO may elect to change its method of tax accounting to increase the portion of expenditures deducted as current repair and maintenance expenses for federal income tax purposes. Mr. Thomas D. Terry, Jr., in PECO Statement No. 12-R, explains the background of this issue including relatively recent changes in the Internal Revenue Service's ("IRS") position that have increased the probability that such a change in method will be accepted while, at the same time, leaving significant uncertainty as to what the IRS will consider an acceptable means of implementing such a change. As Mr. Terry explains, such a change in accounting method, if made, could give rise to a deduction in the year of the change for capitalized expenditures made in prior years, which would be re-characterized for tax purposes as repair expense. It would also apply prospectively. Although PECO, for reasons discussed by Mr. Terry, has not made such a change, Mr. Effron proposes that the Commission establish a method, outside normal ratemaking procedures, to capture the tax effect of any deductions the Company might be entitled to if such an election were made in the future.

12. Q. In view of the fact that the Company has not yet made any change in its method of tax accounting, what is Mr. Effron's concern?

A. Mr. Effron hypothesizes that the Company will change its method of tax accounting in the future, obtain an IRC Section 481(a) "catch-up" adjustment (as explained by Mr. Terry) on its tax return in the year of that change, and continue to obtain higher repair deductions going forward, while customers will not get the entire benefit of the accounting change if it occurs between base rate cases. Consequently, he is proposing an inter-related group of accounting and ratemaking changes to isolate the tax effect of an accounting method change, if it occurs, and pass those tax effects through to customers. He proposes, in substance, that the Company be required to set up a regulatory liability for the tax consequences of the change in tax method and flow the revenue requirement associated with any tax reduction through to customers in the form of a "bill credit" in order to "capture" all of the tax benefits of implementing a tax accounting change from the date the change is first implemented until the conclusion of the Company's next base rate case after the change takes effect.

13. Q. Is Mr. Effron's proposal consistent with the way the Commission in the past has treated the tax benefit of expenditures that were classified as deductible repairs for tax purposes but were capitalized for financial reporting purposes?

A. No, it clearly is not. Pennsylvania is an "actual taxes paid" jurisdiction. This means that the Commission allows utility rates to reflect only taxes that, pursuant to its way of analyzing these things, will actually be paid. It is on this basis that the tax benefit of repairs is considered to be subject to "flow through" tax accounting – that is, the benefit of repairs must be reflected in computing the Company's tax expense in the year in which it is actually claimed on the Company's tax return. And, this is so whether the benefit is claimed in a test year for ratemaking or a non-test year, i.e., between base rate cases. This tax accounting approach is not of the Company's choosing. It is the Commission's rule.

14. Q. Does Mr. Effron concur in this view?

A. Mr. Effron appears to confirm my understanding when he states:

> Absent any mechanism to preserve the benefits of the increased tax deductions for ratepayers, this would provide a windfall to shareholders in the form of immediate, substantial income tax savings.

What he seems to be saying is that the application of "actual taxes paid" tax accounting to this item will result in ratepayers missing a tax benefit because deductions resulting from the method change will hit a tax return in one or more years which are not test years for purposes of a base rate case.

15. Q. Do you agree with his statement?

A. I concur that this could be a possible scenario. However, while Mr. Effron apparently believes this is a problem, it is, in reality, a natural consequence of the "actual taxes paid" approach to calculating the tax allowance for ratemaking purposes. Sometimes "actual taxes paid" works to the benefit of customers, and other times it may benefit shareholders. However, this happens all the time. Consequently, Mr. Effron's "problem" is not a problem at all, but a natural consequence of the consistent application of the "actual taxes paid" approach to reflecting tax expense for ratemaking. As I will explain, Mr. Effron is, in effect, proposing a one-time departure from "actual taxes paid" because he disagrees with the way tax benefits flow-through under that method in this one instance.

16. Q. What is Mr. Effron proposing?

A. Mr. Effron proposes **not** to apply "actual taxes paid" to this item – at least for a few years – and then to apply it thereafter. In other words, he proposes to except this item – and this item only – from this Commission's longstanding and universally applied tax accounting policy until the Company's next rate case and then return to that tax accounting policy.

17. Q. What is the essence of his proposal in this regard?

A. He proposes to capture the tax benefits recognized in non-test years and to flow them through to customers in later years. While he does not propose a specific period over which the "captured" amounts should be flowed through to customers, if the period were to correspond to the regulatory life of the Company's distribution assets, then what he would be proposing would be the conventional "normalization" of the tax benefits generated between base rate cases.

18. Q. What is wrong with Mr. Effron's approach?

A. It is completely inconsistent with the tax accounting policy and practice employed by the Commission for ratemaking. If the natural consequences of the policy and practice that the Commission normally applies (i.e., "actual taxes paid") produce results that are undesirable, then that policy and practice ought to be re-evaluated – not just for this item but for all items to which the policy and practice apply.

19. Q. Are there other defects in Mr. Effron's proposal?

A. The principal defect is that he gives no consideration to the uncertainties surrounding the implementation of a tax method change. Mr. Terry discusses those uncertainties in detail in his rebuttal testimony. As Mr. Terry explains, the Company has not yet made any change in its tax accounting methodology because it is awaiting guidance from the IRS on critical implementation issues. Once guidance is provided by the IRS, the Company will have a better idea of the impact of any change, whether the change can and should be made and, if made, how it can be quantified. Consequently, at this point, the impact of any tax accounting change is not known and measurable and, therefore, does not satisfy the threshold requirement for recognition in the ratemaking process. Pending IRS guidance, it is not clear when, if at all, the accounting method change will be made, hence the effect is not known. Additionally, pending further guidance, the Company cannot quantify the effect of a change if one were to be made, hence the effect is not measurable. In short, current or prospective rate recognition of this item is premature at this time.

Mr. Effron's proposal also is inconsistent with the test year concept employed in ratemaking. Mr. Effron proposes to adjust rates for a specific item that might change between base rate cases while ignoring other changes that affect cost of service.

20. Q. Do you have any recommendation for how the Commission might address this issue?

A. It is premature to address this issue in this case. Also, as Mr. Effron notes, this issue will impact the utility industry as a whole. Rather than address this through piece-meal litigation, the Commission should consider a generic approach to addressing the effects of changes in the capital/expense rules for tax accounting once appropriate guidance has been provided by the IRS.

IV. RATE DESIGN

21. Q. What rate design issues will you address?

A. I will address: (1) Mr. Johnson's proposed customer charge for residential customers; (2) the City's concerns regarding street lighting rate design; (3) Mr. Smith's proposals concerning street lighting and street lighting rates; (4) Mr. Baron's proposals for the Night Service Riders for Rates GS (General Service), PD (Primary Distribution), and HT (High Tension) and for the Large Interruptible Load Rider ("LILR") and Rate GS space heating rate; and (6) Mr. Baron's and Mr. Schneider's proposal concerning the Auxiliary Service Rider.

22. Q. What is Mr. Johnson proposing for the residential customer charge?

A. Mr. Johnson proposes reducing the customer charge from $8.10 per month, as proposed by the Company, to $5.79. Mr. Johnson contends that his proposed reduction is justified because certain costs recorded in Accounts 905 and 903 should be excluded in developing the customer charge. Mr. Johnson contends that the costs he proposes to exclude are not "basic" customer costs that the Commission allows to be recovered in the customer charge.

23. Q. Do you agree with Mr. Johnson's analysis?

A. No, I do not. First, I would note that Mr. Johnson proposes to exclude costs related to processing low-income and CAP rates because he assumes that they are not "basic" billing expenses. However, the Company must enroll eligible customers in its CAP program and must process the bills accordingly. While this process is somewhat more complex than that employed for regular residential bills, it is still basic billing for the customers involved and the associated expense is appropriately included in the customer charge. The Commission, in identifying basic customer expenses, has consistently included costs, such as those recorded in Accounts 903-905, that vary based on the number of customers. Accordingly, including such expenses in the determination of customer-related costs recovered in the customer charge is appropriate. Mr. Johnson also proposes to exclude a significant portion of the "miscellaneous" costs recorded in Account 905. A large portion of the miscellaneous costs he proposes to exclude are information-technology costs associated with the Company's billing system and call center, which are clearly basic customer costs.

While the Company believes it is also appropriate to include as customer-related costs other distribution plant costs and expenses that are allocated in the cost of service study based on number of customers, such as secondary poles and wires, it has not included those categories of costs in developing its proposed customer charge. To include all customer-related costs would have resulted in a customer charge of over $27 per month. Furthermore, as I noted in my direct testimony, PECO's proposal would bring the customer charge to a level consistent with the customer charges of other utilities in the state.

24. Q. What issues has Mr. Buckley raised on behalf of the City with regard to street lighting?

A. Mr. Buckley raises several issues. First, he is concerned that the Company is going to move lamps currently served under Rate AL (Alley Lighting) to Rate SLE, which, if it were to occur, would result in significantly higher charges to the City. Second, he believes that the distribution charges for street lighting may be overstated because street lighting does not entail any metering costs, the City only receives a limited number of bills for street lighting service, and the City maintains its own lights.

25. Q. Please address Mr. Buckley's issues.

A. The concern Mr. Buckley expressed over the lamps billed under Rate AL is unwarranted because the Company is not proposing to move Rate AL customers to Rate SLE. Regarding Mr. Buckley's second issue, the fixed distribution charge for street lighting customers already takes into account the fact that there are no meter-related costs and only limited billing expenditures. The fixed distribution charge primarily covers the costs associated with distribution system costs allocated to street lighting. Regarding maintenance expense, the only maintenance expense included in the development of Rate SLE or Rate AL is associated with the Company' distribution system. The costs of maintaining streets lights themselves are allocated to lights served under Rate SLS and Rate POL (i.e., where the fixture is owned by the Company), not Rate AL or Rate SLE (i.e., where the fixture is owned by the customer). I would also note that, while the City receives a limited number of bills, it does have a dedicated account representative and, at times, can have a number of PECO employees involved in analyzing issues the City may have with its bills and payment of the bills.

26. Q. Has the Company made any changes to the lighting tariffs since the filing?

A. Yes. The Company has modified Rate AL to remove references to incandescent lights and also to clarify that the rate will be closed to new lamps effective January 1, 2011. Additionally the City noted that the Energy Efficiency and Conservation Program Charge ("EEPC ") shows an average rate for lighting customers even thought each lighting rate has its own charge. The Company has modified the relevant EEPC tariff page to reflect the EEPC for each lighting tariff rate. I have attached a copy of the two portions of the Company's tariff that have been changed, which are identified as Exhibit ABC-1R and Exhibit ABC-2R.

27. Q. Please summarize Mr. Smith's proposal regarding street lighting rates.

A. Mr. Smith believes that PECO should offer a service, and an associated rate, for street lights that automatically turns off at midnight through the use of a programmable photo controller. He also proposes that PECO offer a 50-watt high-pressure sodium street light option.

28. Q. Do you agree with Mr. Smith?

A. No. First, with regard to the 50-watt high-pressure sodium street light option, I note that most street lighting customers own their lights, and the decision to install a 50-watt high-pressure sodium lamp is theirs, not the Company's. If the customer does not own its lights, it is eligible to purchase the street lights and use whatever wattage it wants, just as the majority of customers have already done. Regarding Mr. Smith's proposal for a service that turns off lights at midnight, there has been no expression of interest from customers at this time for such a service. If, in the future, municipalities express interest in the midnight shut-off option, PECO would consider a tariff change. At this point, however, it appears that the option Mr. Smith proposes may raise issues concerning safety and security that municipal customers would have to consider.

29. Q. What is Mr. Baron's proposal for the Night Service Rider?

A. Mr. Baron proposes retaining the Night Service Rider and increasing the associated demand charge by the same percentage as the increase in the demand charge for the underlying rate – i.e. HT, PD, or GS. He believes that, if distribution costs are driven by the non-coincident peak demands, then customers should still receive a benefit if their highest demands occur in the off-peak period.

30. Q. Do you agree with Mr. Baron's proposal?

A. No. As I explained in my direct testimony, the Night Service Rider was developed to provide a reduced cost for customers that shift **generation** to the off-peak period. Going forward, the market should provide the cost incentive for such load shifting. Although I noted that distribution costs are driven by non-coincident peak ("NCP") load, the class size used to determine such NCP load is important. If Night Service Rider customers are grouped as a class, then their NCP load would be in the off-peak period. For purposes of PECO's cost of service study, the number of classes has been limited (which benefits Night Service Rider customers). However, in determining the appropriate distribution charges, Night Service Rider customers should be treated like any other customer and billed on the basis of their maximum demand. In this way, all of the customers in the class benefit from the diversity of peak demands. Assigning any benefit directly to a small group of customers would be contrary to the philosophy of average rates. Each class has diversity with respect to peak loads, and to provide special treatment to one group is not appropriate absent definitive cost benefits.

31. Q. Would eliminating the Night Service Rider discourage customers from shifting load to the off-peak period?

A. No, I do not believe it would have a significant impact because the cost of energy will be the driver for such load shifting.

32. Q. What is Mr. Baron's proposal with regard to the LILR, the Auxillary Service Rider and the Rate GS space heating rate?

A. While not objecting to the Company's proposal to eliminate or modify these rates, Mr. Baron proposes to cap the increase to those customers at twice the average Rate HT distribution increase.

33. Q. Do you agree with Mr. Baron's proposal?

A. No. First with regard to the LILR, what appears to be a large increase is the result of customers currently paying a very low rate. The existing low rate is a function of the interruptible nature of the LILR. As such, the LILR had its own set of transmission and distribution rates and its own night service rider terms. Those terms resulted in a significant portion of the customers' usage being billed at the end block price, which is the lowest price in a declining block price structure. Furthermore, the increase of 125% discussed by Mr. Baron is based on distribution charges only. As shown on Exhibit ABC-3R, when viewed in the context of the total bill increase, the percentage drops to the 10% range, which is reasonably close to the average for some of the other rate classes. Going forward, the Company will treat these customers the same as any other distribution customer.

Second, with regard to the Rate GS space heating rate, as explained in my direct testimony, the lower rate was a throw-back to bundled rates and was intended to provide a benefit to customers that required generation in the winter for heating. In evaluating the impact on customers, it is appropriate to review the overall bill impact, not just distribution charges. The response to Supplemental Data Request IV-D-2, at pages 9-12 (which is part of the Company's initial filing), provides an estimate of the impact on heating customers. As shown in that response, the impact on customers depends upon the current load factor for base usage and the load factor for heating usage. As with all rate increases, some customers will receive a higher than average increase and some lower than average. I would also note, as shown in the response to Supplemental Data Request IV-D-2, the larger percentage increases in distribution rates translate into a much lower percentage increase when viewed in the context of a customer's **total** bill.

Finally, with regard to the Auxiliary Service Rider ("ASR"), I would again point out that what appears to be a large percentage increase is the result of a low current average rate. The low rate was the result of the unbundling of rates at the time restructuring occurred. Another driver of the increase is the fact that ASR customers pay very little unless they take power. The current proposal treats these customers the same as other distribution customers and charges for the minimum contract demand. Exhibit ABC-4R shows an estimate of the impact on Kimberly Clark's bill. As shown there, the impact on the total bill, even with a 300% increase in distribution charges, is only about 16%. While higher than the average increase for any of the major classes, it is not unusual to have individual customers receive a higher than average increase.

34. Q. Mr. Schneider notes that the change in the Auxiliary Service Rider will take away the incentive for customers on that rider to perform maintenance on

customer-owned generation during the off peak period. Do you agree with that contention?

A. No. The decision to do maintenance in the off-peak period will undoubtedly be driven by the market price of the energy that the customer will require and not by the distribution charges. Lower off-peak energy prices will keep the maintenance cost lower and reduce the customer's opportunity cost from losing sales of its excess generation into the market.

35. Q. Mr. Baron also proposes that transmission revenue be collected from the large commercial and industrial customers based upon on-peak demand. Do you agree that such a change is appropriate?

A. No. While it is correct that transmission costs charged to the Company are based upon a single peak demand that likely occurs during on-peak hours, there is still significant diversity in demand for individual customers. Some customers might peak after 8:00 PM, while others might peak at 10:00 AM. Given that diversity of load, it is appropriate to recover transmission costs based upon maximum measured demand.

V. REVENUE ALLOCATION

36. Q. Please summarize the various revenue-allocation proposals.

A. Alternative allocation proposals were made by witnesses on behalf of the OCA, OSBA, PAIEUG, and the Commercial Group. The OSBA, PAIEUG and the Commercial Group allocations were based on the Company's cost of service study, while the OCA's proposal was based on its witness' cost of service study. The OCA also proposes allocating transmission revenue based upon the 12 coincident peak ("12 CP") method, which is an issue that is being addressed in the rebuttal testimony of Mr. Howard Gorman. All of the witnesses that made alternative proposals acknowledged the need to consider the principle of gradualism and purported to apply that principle while also trying to achieve the goal of moving classes to their indicated cost of service. For example, the OSBA proposes capping any class increase to 150% of the average distribution increase and also proposes excluding any increase in transmission revenue from the determination of the revenue allocation since it is effectively a pass-through of cost. PAIEUG proposes reducing any inter-class subsidies by 50%. The Commercial Group's proposal has a goal of limiting its increase to 125% of the average distribution increase. Exhibit ABC-5R is a schedule that compares the proposed alternative allocations in terms of dollars and percent of total bill.

37. Q. After reviewing these proposals, does the Company believe that any change is called for in its revenue allocation proposal?

A. No, it does not. There are many ways to allocate the increase that purport to give due consideration to cost of service and the principle of gradualism, as illustrated by the various proposals put forth in this case. However, as Exhibit ABC-5R shows, the Company's proposal provides a reasonable and, in my opinion, the best, balancing of those interests. The Company's allocation of the increase is in the middle range of alternatives, and the total bill impacts are all within a reasonable range for the major classes. Additionally, I would note that the exclusion of transmission revenue in determining the proper allocation and rates of return is inappropriate because transmission expense is an integral cost of providing service and must be considered when viewing the total impact on the customers.

38. Q. Do the different parties propose to change the method of scaling back the allocation if the Commission grants less than the Company's requested increase?

A. The OCA and OSBA propose alternative approaches. The OCA's scale back would encompass the customer charge and, as such, would reduce customer charges proportionally. The OSBA would eliminate inter-class "subsidies" on a "first-dollar" basis before proportionately scaling-back. The concept of "first dollar" relief, as Mr. Kalcic conceives it, was explained by him as follows (OSBA Statement No. 1, p. 10):

> When a Commission awards a utility less than its full revenue request, the "disallowed" portion of the request becomes available to (further) address such subsidy concerns. Under FDR [first dollar relief] proposal, an initial (first) portion of that revenue disallowance, or rate relief, is directly assigned to one or more over-contributing classes, rather than shared among all rate classes. Conversely, the non-FDR rate classes receive rate relief only if (or after) all FDR award levels have been assigned.

39. Q. Does the Company agree with either alternative?

A. No. The fixed customer charge should not change because it is recovering a level of customer-related costs that is well below fully allocated customer costs. Consequently, no scale back of the customer charge is justified. Eliminating inter-class "subsidies" through first-dollar relief cannot be implemented as readily or precisely as the OSBA assumes. The changes that could result from the Commission's final Order could significantly alter the alleged "subsidies" and, as explained in my direct testimony, the Commission uses the cost of service study as a guide.

Furthermore, the "first dollar" relief methodology tries to side-step the principle of gradualism through the unjustified assumption that any revenue "disallowed" becomes "available" to give disproportionate "relief" to some classes. In so doing, the first dollar relief method implicitly assumes that the increase first proposed for a class that is allegedly being "subsidized" should be deemed acceptable irrespective of the overall level of revenues actually determined by the Commission. As a result, the first dollar formula can produce results that are difficult to assess for reasonableness because the increase any class might receive is a function of the overall level of revenue allowed by the Commission. Thus, if a rate structure is proposed that would close the gap between cost of service and revenues by 50% for a given class and, thereafter, the "first dollars" of any overall revenue reduction are directly assigned to specific classes, the 50% target would become meaningless. Eliminating the alleged "subsidies" on a first dollar basis would move the affected class or classes all the way to the initially determined cost of service notwithstanding the "gradualism" embodied in the initial proposal. Stated another way, the use of first dollar relief changes the metrics for measuring movement toward cost of service between an initial proposed revenue allocation and the final revenue allocation in a way that masks the real impact on individual classes. The better approach is for all parties to present their proposed revenue allocations based on a common starting point, such as the Company's proposed revenue increase, and, if less than the requested increase is granted, to scale-back the revenue allocation proportionately.

VI. LEGACY METER COSTS

40. Q. Please summarize Mr. Johnson's issues regarding the inclusion of legacy meter costs in the Smart Meter Cost Rider.

A. Mr. Johnson expresses several concerns with including legacy meter costs in the Smart Meter Surcharge. First, he is concerned that including legacy costs in the surcharge will allow the Company to pass through increases in the operating cost of the legacy system. Second, he is concerned that the proposal would include a fixed-charge component in the Smart Meter Surcharge even though the surcharge is supposed to collect Smart Meter costs on a per-kilowatt hour basis pursuant to the Order approving PECO's Smart Meter implementation plan. Third, while he agrees that it is appropriate to pass cost savings back to customers, he believes that such savings can be estimated and trued up in the surcharge. In the alternative, Mr. Johnson proposes that, if the Commission allows the legacy costs to be included in the surcharge, three criteria should be satisfied: (1) all costs should be recovered on a kilowatt hour basis; (2) the cost recovered in the surcharge should be removed from the base rate customer charge; and (3) the cost should be capped at the level set in this base rate case.

41. Q. Please address Mr. Johnson's concerns and his alternative proposal.

A. Regarding Mr. Johnson's first concern, that including the legacy cost in the surcharge will allow the Company to pass through increases in cost, I would note that the Company identified this as a potential issue and proposed to include only those components of meter costs that would assure that the potential problem identified by

Mr. Johnson will not occur. The only expenses being passed through are meter reading, depreciation on the meters owned by the Company, and the asset use fee paid for meters owned by Landis & Gyr, the operator of the Company's AMR system who also owns a significant portion of the meters. The meter reading and asset-use fees are imposed under a contract with a fixed price. Depreciation of the current meters was established in the settlement of the Company's Smart Meter implementation plan. I would expect such costs to go down over time as assets are depreciated and legacy meters are replaced with the new smart meters, thus reducing the cost of meter reading and asset use fees.

As to Mr. Johnson's concern that the Company would be including a fixed-charge component in the Smart Meter surcharge, notwithstanding that the Order approving its Smart Meter implementation plan requires a kilowatt hour charge, I would note that the kilowatt hour charge is for Smart Meter costs whereas this addition to the surcharge proposed in this case is not for Smart Meter costs but, instead, for legacy meter costs. The Company's proposal represents a change to the Smart Meter Surcharge and that is why the Company is requesting approval of the change in this case. The change, however, is to add a cost component -- legacy meter costs -- not to change what is already in the surcharge – costs of new, Smart Meter technology. If all of the legacy costs were already included in the current surcharge, there would be no need to file for a change. Moreover, PECO is proposing to continue to recover the legacy costs on the very same basis and in the very same way those costs are recovered in base rates, namely, in the customer charge.

As to the three criteria offered by Mr. Johnson under his alternative proposal, the Company agrees with the second, but the first and third are not appropriate and should not be adopted. The first criterion would require that legacy costs be recovered on a kilowatt hour basis because that is what the Smart Meter surcharge requires. However, the surcharge was approved before the Company requested that legacy costs be included in that surcharge and, therefore, the Commission can properly accept the Company's proposal in this case as a modification of the previous surcharge for the legacy meter costs only. As I previously explained, there is no dispute that such legacy costs are currently recovered on a customer basis in the customer charge. And, since legacy costs are not "Smart Meter" costs, the requirement that Smart Meter costs be recovered on a per-kWh basis simply does not apply. The Company agrees with the second criterion, namely, that the costs recovered in the surcharge should be excluded from base rates in order to avoid double recovery. Finally, the third criterion, which would impose a cap on the surcharge for legacy costs, would not be appropriate because it would be asymmetrical. That is, cost reductions would be passed through while increases would not. However, if the "cap" on legacy cost were to apply only between base rate cases, then it would be acceptable to the Company.

42. Q. Mr. Johnson notes that there was \$2.7 million included in Other Revenue that is associated with the American Recovery and Restoration Act ("ARRA") that, in his opinion, should offset Smart Meter plant. Is he correct?

A. No. While most of the ARRA \$200 million grant will be applied to the Smart Meter plan, approximately 25% of the total is for Smart Grid projects. A portion of the 25%

that will be used for Smart Grid is for operation and maintenance ("O&M") expense and a portion is for capital. The $2.7 million identified by Mr. Johnson is associated with Smart Grid-related O&M expense and was appropriately included as Other Revenue in the 2010 budget to offset the approximate $5.5 million in Smart Grid expenses that are in the test year. Since the budget was developed, the accounting for the ARRA reimbursement associated with expenses has been changed to a contra-expense.

VII. SMART METER COSTS -- UPDATE

43. Q. How will PECO assure that the appropriate credit from the ARRA is being passed through the Smart Meter Charge?

A. In order to receive the grant, PECO had to establish a detailed tracking system for qualifying expenditures. Each qualifying expenditure will receive a reimbursement from the DOE based on a fixed percentage. The Company's accounting system will track all of the expenditures, and those that are smart-meter related will be deferred for recovery through the Smart Meter Surcharge. Any deferral will be net of the accrued credit received under the ARRA. If the credit is against capital, it will reduce the rate base and depreciation for recovery. If the credit is against expense, it will be a dollar-for-dollar reduction of recoverable cost. Credits associated with Smart Grid projects will result in reduced investment and a lower rate base in the future. Smart Grid costs are not recoverable in the Smart Meter surcharge.

44. Q. How is PECO separating Smart Meter costs from normal operating costs and assuring that only incremental costs are recovered in the Smart Meter Surcharge?

A. The Company has established specific projects and procedures for tracking the Smart Meter costs. This is necessary to assure the appropriate dollars are recovered in the surcharge and in order to submit expenditures to the DOE to receive the ARRA credit. In the context of capital charges, all smart meter cost are incremental. For purposes of expenses to be recovered in the Smart Meter Surcharge, it will consist of costs not previously being incurred, with the most significant cost being labor and associated costs. Labor is considered incremental for the project if it is a contractor's expenditure or an expenditure for new hires for the Smart Meter Project, or if it is an internal transfer and there is documentation that the employee's prior position has been filled. Internal transfers are not considered incremental until such time as the prior position is filled. At that time the cost is recoverable on a going-forward basis. Because the Smart Meter Surcharge is a Section 1307 cost recovery mechanism, it is subject to audit. The audit will verify that the appropriate cost and ARRA credit have been included in the surcharge.

VIII. DEFAULT SERVICE – ADMINISTRATIVE COST UPDATE

45. Q. Can you provide an update to Exhibit ABC-14 that reflects the latest estimate of default service costs to be recovered in the administrative cost adder in the Generation Service Adjustment ("GSA")?

A. Yes. Exhibit ABC-6R provides an update to Exhibit ABC-14. As shown on Exhibit ABC-6R, there have been some decreases in estimated capital costs and some small increases in O&M expenses that are to be recovered in the administrative charge of the GSA. Overall, however, the costs are coming in close to the estimate. As noted in my direct testimony, the capital costs and expenses included in Exhibit ABC-14 have been excluded from the test year capital and expense in this case as they are default service costs to be recovered in the GSA.

IX. CONCLUSION

46. Q. Does that conclude your rebuttal testimony?

A. Yes, it does.

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RATE AL - ALLEY LIGHTING IN CITY OF PHILADELPHIA

APPLICABILITY. To multiple, unmetered lighting service supplied by the City of Philadelphia to operate lamps and appurtenances ~~for all night outdoor lighting of alleys and courts that are~~ installed, owned and maintained by the City, which assumes the cost involved in making the connections to the Company's facilities. ~~This rate shall no longer be available to new lighting installations effective January 1, 2011.~~

LIGHTING DISTRIBUTION SERVICE DEFINED. All-night outdoor lighting of alleys and courts by lights installed on poles or supports supplied by the City.

NOTICE TO COMPANY. The City shall give advance notice to the Company of all proposed new installations or of the replacement, removal or reconstruction of existing installations. The City shall advise the Company as to each new installation or change in the equipment or connected load of an existing installation, including any change in burning hours and the date on which such new or changed operation took effect.

MONTHLY RATE TABLE.

SERVICE LOCATION CHARGE: $2.11 PER LOCATION

ENERGY SUPPLY CHARGE: Refer to the Generation Supply Adjustment Procurement Class 2

TRANSMISSION SERVICE FOR CUSTOMERS RECEIVING DEFAULT SERVICE: The Transmission Service Charge shall apply.

©

STATE TAX ADJUSTMENT CLAUSE, MITIGATION PLAN SURCHARGE AND NUCLEAR DECOMMISSIONING COST ADJUSTMENT CLAUSE APPLY TO THIS RATE

PLAN OF MONTHLY BILLING.
Bills may be rendered in equal monthly installments, computed from the calculated annual use of energy, adjusted each month to give effect to any new or changed rate of annual use, by reason of changes in the City's installation, with charge or credit for fractional parts of the month during which a change occurred.

LIABILITY PROVISION.
The Company shall not be liable for damage, or for claims for damage, to persons or property, arising, accruing or resulting from, installation, location or use of lamps, wires, fixtures and appurtenances; or resulting from failure of any light, or lights, to burn for any cause whatsoever.

TERM OF CONTRACT.
The initial contract term for each lighting unit shall be for at least one year.

Exhibit ABC-2R

Supplement No. XX To
Tariff Electric PA. P.U.C. No. 4
Second Revised Page No. 34D
PECO Energy Company **Superseding First Revised Page No. 34D**

PROVISION FOR THE RECOVERY OF ENERGY EFFICIENCY AND CONSERVATION PROGRAM COSTS (EEPC)

Purpose: The purpose of this surcharge is to provide for full and current cost recovery of expenditures associated with the Company's Energy Efficiency and Conservation Program Costs (EEPC) as approved at Docket No.M-2009-2093215.

Applicability: The surcharge shall be a calculated to the nearest one-hundredth of a cent for billing purposes for all customers. The EEPC shall be included in each rate schedule as follows:

Rates R, R-SP, RT, RS, RH, OP, CAP: 0.34 ¢/kWh
Rates GS, GS-SP: 0.27¢/kWh
Rates POL: average of $0.36/lamp, actual surcharge varies with lamp type/size, SL-S: average of $0.53/lamp, actual surcharge varies with lamp type/size, SL-E: $0.46/location outside of the City of Philadelphia, $0.63/location within the City of Philadelphia. AL: $0.17/location TLCL: $0.009/kWh (C)

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Rates HT, HT-SP, PD, PD-SP, EP: $0.91/kW based on PJM Peak Load Contribution

The Variable Distribution Service charges, for the residential rate schedules shall include the above listed EEPC surcharge. For the municipal lighting rate schedules, the applicable variable or fixed distribution service charges shall reflect the EEPC surcharge.

For Rate GS, the EEPC shall be recovered through a separate variable distribution charge listed on customer's bills. For Rates PD, HT and EP, a PJM Peak Load Contribution (PLC) shall be determined in accordance with PJM rules and used to calculate the EEPC. Customer's PLC will be computed to the nearest kilowatt. The EEPC shall be recovered through a separate variable distribution charge listed on customer bills.

Calculation of EEPC Surcharge:

Billing Provisions: The surcharge shall be calculated by rate schedule using the following formula:

$$\textbf{EEPC} = \frac{(C)+(SWE)}{(BU)} \times \frac{(1)}{(1-T)} \quad \text{where;}$$

C – The cost of the Energy Efficiency and Conservation Program includes: all expenditures, of the individual programs such as materials, equipment, installation, custom programs, evaluation measurement/verification, educating customers about availability to the extent not included in Consumer Education cost, not recovered through any separate recovery mechanism, and any other cost associated with implementation of the programs. Any direct load control benefits to the Company from the programs shall be credited against the cost. The program costs are those approved by the PAPUC and audit costs for the program ending May 31, 2013.

SWE – The cost in dollars of the PaPUC's Statewide Evaluator. These costs will be reconciled separately and added to the EEPC and will not be subject to the 2% spending limit of the EE&C Plan.

BU – The total Billing Units for the applicable recovery period commencing on January 1, 2010 and ending May 31, 2013.

T – The current Pennsylvania gross receipts tax rate included in base rates.

Filings and Reconciliations: A reconciliation filing will be made May 31 of each year although the rates will not be adjusted until May 31, 2013 of the final plan year, at which time any under or over recoveries will be reflected in rates in effect through December 31, 2013. If it is apparent that such methodology would result in a significant over or under recovery at May 31, 2013 for an individual customer class the Company will propose a rate adjustment prior to May 31, 2013. Interest will not be applied to any over or undercollections.

(C) Indicates Change

PECO Energy Company - Electric Division
Estimated Impact on LILR Customers Total Bill

Total Annual Customer Revenue	$	16,018,445
Current annual Distribution Revenue	$	1,706,081
Estimated Average Distribution % Increase		99%
Estimated Distribution $ Increase	$	1,689,020
Estimated Average % Increase in Total Bill		10.5%

PECO Energy Company - Electric Division
Impact of Distribution Increase on Kimberly Clarke

Total Annual Customer Revenue	$	1,671,270
Current annual Distribution Revenue	$	90,842
Estimated Average Distribution % Increase		300%
Estimated Distribution $ Increase	$	272,526
Estimated Average % Increase in Total Bill		16.3%

PECO Energy Company - Electric Division
Comparison of Revenue Allocations
(Million $)

	PECO	OCA	OSBA	PAIEUG	CG
R	$ 145.5	$ 134.3	$ 159.0	$ 155.1	$ 181.1
RH	$ 33.2	$ 33.1	$ 35.6	$ 33.9	$ 35.3
OP	$ 3.7	$ 4.9	$ 3.8	$ 3.8	$ 3.9
GS	$ 91.0	$ 92.6	$ 78.6	$ 82.6	$ 66.1
PD	$ 0.7	$ 0.1	$ 0.6	$ 0.6	$ 0.6
HT	$ 40.6	$ 48.9	$ 26.4	$ 28.6	$ 18.4
EP	$ 0.7	$ 1.0	$ 1.6	$ 1.0	$ 1.6
L	$ (0.3)	$ 0.2	$ 9.5	$ 9.5	$ 8.1
Total	$ 315.1	$ 315.1	$ 315.1	$ 315.1	$ 315.1

% of Total Bill

	PECO	OCA	OSBA	PAIEUG	CG
R	9.5%	8.8%	10.4%	10.1%	11.8%
RH	9.2%	9.2%	9.9%	9.4%	9.8%
OP	8.3%	11.0%	8.5%	8.5%	8.8%
GS	9.0%	9.2%	7.8%	8.2%	6.5%
PD	1.0%	0.1%	0.9%	0.9%	0.9%
HT	2.9%	3.5%	1.9%	2.0%	1.3%
EP	0.9%	1.3%	2.1%	1.3%	2.1%
L	-0.8%	0.5%	24.7%	24.5%	21.1%
Total	6.9%	6.9%	6.9%	6.9%	6.9%

PECO Energy Company
GSA Administrative Costs for Recovery
($1000)

Cost Element	Capital	Expense	
IT/Billing System(a)	$ 3,431	$ 499	
IT/Energy Acquisistion(a)	$ 5,065	$ 561	
Independent Evaluator(a)		$ 1,038	Includes legal cost and consutlant cost
Cost of DSP Proceeeding(b)		$ 3,581	
Other Implementation Cost(c)		$ 1,020	
Total	$ 8,496	$ 6,699	

(a) Capital is estimated completion cost excluding AFUDC; O&M is actual spend to date

(b) Cost includes the following

1. Outside legal counsel	$ 981
2. Consultants	$ 2,411
3. Proof of revenue	$ 108
4. Load Study	$ 80
5. Other	$ 1
Total	$ 3,581

(c) Includes cost of customer notification of procurment class, CAP customer notification, release of information costs, temporary call center support