OCA STATEMENT NO. 1

Hbg TX AUG 13 2007

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

PPL ELECTRIC UTILITIES)
CORPORATION) DOCKET NO. R-00072155

DIRECT TESTIMONY OF

LAFAYETTE K. MORGAN, JR.

RECEIVED

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PA PUBLIC UTILITY COMMISSION
SECRETARY'S BUREAU

Topics Addressed:
Revenue Requirement
Rate Base, Revenues, Expenses, Taxes, and Riders

ON BEHALF OF THE

OFFICE OF CONSUMER ADVOCATE

DOCUMENT
FOLDER

JULY 2007

EXETER
ASSOCIATES, INC.
5565 Sterrett Place
Suite 310
Columbia, Maryland 21044

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Direct Testimony of Lafayette K. Morgan, Jr.

Introduction and Summary

Q. WOULD YOU PLEASE STATE YOUR NAME AND BUSINESS ADDRESS?

A. My name is Lafayette K. Morgan, Jr. I am a Senior Regulatory Analyst with Exeter Associates, Inc. Our offices are located at 5565 Sterrett Place, Columbia, Maryland 21044. Exeter is a firm of consulting economists specializing in issues pertaining to public utilities.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND QUALIFICATIONS.

A. I received a Master of Business Administration degree from The George Washington University. The major area of concentration for this degree was Finance. I received a Bachelor of Business Administration degree with concentration in Accounting from North Carolina Central University. I am also a Certified Public Accountant licensed in the State of North Carolina.

Q. WOULD YOU PLEASE DESCRIBE YOUR PROFESSIONAL EXPERIENCE?

A. From May 1984 until June 1990, I was employed by the North Carolina Utilities Commission - Public Staff in Raleigh, North Carolina. I was responsible for analyzing testimony, exhibits, and other data presented by parties before the North Carolina Utilities Commission. I had the additional responsibility of performing the examinations of books and records of utilities involved in rate proceedings and summarizing the results into testimony and exhibits for presentation before that Commission. I was also involved in numerous special projects, including participating in compliance and prudence audits of a major utility and conducting research on several issues affecting natural gas and electric utilities.

From June 1990 until July 1993, I was employed by Potomac Electric Power Company (Pepco) in Washington, D.C. At Pepco, I was involved in the preparation of the cost of service, rate base and ratemaking adjustments supporting the company's requests for revenue increases in the State of Maryland and the District of Columbia. I also conducted research on several issues affecting the electric utility industry for presentation to management.

In July 1993, I accepted my current position with Exeter Associates, Inc. Since then, I have been involved in the analysis of the operations of public utilities, with particular emphasis on utility rate regulation. I have also been involved in the review and analysis of utility rate filings, focusing primarily on revenue requirements determination. This work has involved natural gas, water, electric and telephone companies.

Q. HAVE YOU PREVIOUSLY TESTIFIED IN REGULATORY PROCEEDINGS ON UTILITY RATES?

A. Yes. I have previously presented testimony and affidavits on numerous occasions before the North Carolina Utilities Commission, the Pennsylvania Public Utility Commission, the Virginia Corporation Commission, the Louisiana Public Service Commission, the Georgia Public Service Commission, the Maine Public Utilities Commission, the Kentucky Public Service Commission, the Public Utilities Commission of Rhode Island, the Vermont Public Service Board, the Illinois Commerce Commission and the Federal Energy Regulatory Commission (FERC).

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. Exeter Associates has been retained by the Office of Consumer Advocate (OCA) to review the reasonableness of the level of revenues which PPL Electric Utilities Corporation (PPL or the Company) is proposing to charge its customers. In this testimony, I present my findings on behalf of the OCA regarding certain adjustments to PPL's future test year rate base and net operating income at present rates. In addition, I also present a summary of the OCA's findings regarding the current levels of PPL's earnings and determine the necessary change in its revenues that is required to produce an overall rate of return on rate base of 7.56 percent. This return is based on the recommendation of OCA witness David C. Parcell.

Q. IN CONNECTION WITH THIS CASE, HAVE YOU PERFORMED AN EXAMINATION AND REVIEW OF THE COMPANY'S TESTIMONY AND EXHIBITS?

A. Yes. I have reviewed PPL's testimony and exhibits, its rate filing, as well as its responses to the OCA's, and the Office of Trial Staff's (OTS) data requests.

Q. WOULD YOU PLEASE SUMMARIZE WHAT IS PRESENTED ON THE ATTACHED SCHEDULES?

A. Yes. I have prepared a set of schedules that present my findings and recommendations regarding the Company's rate base and net operating income. Schedule LKM-1 summarizes my overall findings regarding net operating income. Schedule LKM-2 presents a summary of rate base and my adjustments thereto. Schedule LKM-3 summarizes each of my adjustments to PPL's net income. Schedule LKM-4 presents a reconciliation of the current income taxes. The remaining schedules show the derivation of each of my adjustments to rate base and net operating income.

Q. PLEASE SUMMARIZE YOUR FINDINGS.

A. As shown on Schedule LKM-1, I have determined the appropriate change in PPL's distribution revenues to be a $34.6 million increase as compared to the Company's request of $83.6 million. This represents a reduction of $49.0 million in the Company's requested distribution revenue increase.

The OCA recommended distribution revenue increase would result in a 5.1 percent increase in distribution revenue instead of 12.4 percent proposed by the Company.

Q. WHAT TIME PERIOD DID YOU USE IN YOUR ANALYSIS OF THE COMPANY'S OPERATING RESULTS?

A. The Company's filing includes revenue requirement analyses based upon both a historical test period ended December 31, 2006 and a future test period ending December 31, 2007. I have based my analysis of the Company's operating results on the future test year ending December 31, 2007. This is the same period used by the Company to determine its requested rate increase in its rate filing, direct testimony and exhibits.

Q. HOW IS THE REMAINDER OF YOUR TESTIMONY ORGANIZED?

A. The remainder of this testimony addresses each of the adjustments that I am recommending and is presented in the order identified in the table of contents to this testimony. For each issue, I will document and explain why it was necessary to make the adjustment.

Rate Base Adjustments

Plant Held for Future Use

Q. PLEASE EXPLAIN YOUR ADJUSTMENT TO PLANT HELD FOR FUTURE USE (PHFU).

A. In this proceeding, PPL's filing reflects the inclusion in rate base of $2.0 million of land and rights-of-way recorded in the PHFU account. According to the Company's testimony, the land and rights-of-way were purchased for future substations and distribution projects. While the Company's filing reflects the inclusion of PHFU in rate base, PPL witness Douglas Krall indicates in his direct testimony that, as an alternative, the Company will accept approval for the authority to accrue an Allowance For Funds Used During Construction (AFUDC) on the PHFU investment, and to be allowed to recover the accrued AFUDC at the time any of the PHFU is placed in service.

My adjustment removes the entire balance of PHFU from rate base. This adjustment is necessary because in order for plant to be included in rate base, it must be used and useful. The PHFU that PPL has included in rate base does not meet the used and useful standard. On Schedule LKM-5, I present this adjustment which reduces Pennsylvania jurisdictional rate base by $2.0 million.

Q. YOU INDICATED THAT PPL IS REQUESTING THE AUTHORITY TO ACCRUE AFUDC ON PLANT HELD FOR FUTURE USE AS AN ALTERNATIVE TO INCLUDING THEM IN RATE BASE. WHAT IS YOUR POSITION ON THAT PROPOSAL?

A. I am recommending that the Commission accept PPL's alternative request and allow the Company to accrue AFUDC on the PHFU that was presented in this proceeding. However, I believe the recovery of any accrued AFUDC is still subject to the normal regulatory oversight. In other words, authorizing the accrual of AFUDC by the Commission should not be construed to mean that the right of any party to challenge the recovery of the plant costs, including the accrued AFUDC, has been precluded.

Allowance for Cash Working Capital

Q. HOW DO YOU DEFINE CASH WORKING CAPITAL?

A. For ratemaking purposes, cash working capital is the investment that a utility needs to have on hand to fund its day-to-day operations. Positive cash working capital represents funds provided by investors that should be included in rate base so that the Company earns a return on it. Negative cash working capital represents funds supplied by ratepayers which should be recognized as a rate base offset.

Q. HOW DID THE COMPANY REFLECT CASH WORKING CAPITAL IN ITS FILING?

A. The Company's cash working capital allowance is calculated based upon the results of a lead-lag study. A lead-lag study is an in-depth analysis that measures the difference between the lapse of time when the Company receives revenue for the provision of service and the lapse of time when the Company pays for the costs of providing service. This difference, expressed as a number of days, is used to calculate the level of investor-supplied funds advanced for operations if the difference is positive. If the difference is negative, it is used to calculate the funds advanced by customers.

The revenue lag represents the average number of days from the date on which service is provided to the customers until the date on which payment is received from the customers. It is measured from the midpoint of the service period covered by the bill to the date payment for that service is received by the Company. The Company's expense lag represents the average number of days from the date the expense is incurred in rendering service until the date the expense is paid.

After both the Company's revenue lag and expense payment lag have been determined, one can make a reasonable approximation of the Company's cash working capital requirement. This calculation is made by dividing the expenses by 365 days to determine the average daily amount. The average daily amount is multiplied by the net lead-lag days (the difference from subtracting the expense lag from the revenue lag) to derive the Company's working capital requirements. If the total working capital requirement is positive, it represents a level of funds that must be included in rate base so that the Company is provided a return on the funds supplied by investors. Conversely, if the amount is negative, then the amount reduces rate base to recognize funds that customers have advanced.

Q. PLEASE DEFINE THE TERMS "LEAD" AND "LAG" AS YOU USE THEM IN YOUR TESTIMONY.

A. The term "lead" is used to indicate either the receipt of revenue prior to the date that service is provided or the payment of an expense prior to the date that the expense is incurred. The term "lag" is used to indicate either the receipt of revenue after the date that service is provided or the payment of an expense after the date that the expense is incurred.

Q. WHAT ADJUSTMENTS HAVE YOU MADE TO THE ALLOWANCE FOR CASH WORKING CAPITAL?

A. I have made several changes to the lag day determination that was used for certain expense items in the cash working capital allowance. The Company performed a voucher study to determine the number of lead or lag days for the various expenses. A voucher study involves reviewing the invoices supporting various expenses to determine the service period and the payment date for each transaction selected. From that data, the lag or lead days assigned to each expense item is determined. As part of my examination of the calculation of the net lag days for the various expenses, I reviewed the additional data provided by the Company in response to OTS' interrogatories. There are several instances where I disagree with the lag days used by PPL. My disagreement generally involves the date the Company has used for the service period, which has the effect of shortening the expense lag days (and increasing the working capital allowance). For each of those instances, I have recalculated the lag days. I will explain why I disagree with the calculation and how I have corrected those lag days later in this section of my testimony.

In addition to the changes that I have made to certain lag days, I have adjusted the cash working capital study to reflect the level of expense deemed necessary for utility operations. As a result of the various O&M expense adjustments that I have made to the cost of service, it is necessary to reflect those adjustments in the expenses contained in the lead-lag study to avoid a misstatement of the cash working capital allowance. On Schedule LKM-6, page 2, I show the removal of the various O&M expense adjustments that I have made from the expenses used in the cash working capital study.

Q. CAN YOU EXPLAIN IN DEPTH THE CHANGES YOU HAVE MADE TO THE CALCULATION OF THE LAG DAYS?

A. Yes. The changes I made to the lag days were all related to the lag days for Other Operating Expenses. The first category affected is Materials and Supplies expense. Within this category, I disagree with the lag days calculated for Pennsy Supply, Inc. and Signalcrafters. With regard to the Pennsy Supply lag days, PPL calculated the lag days based on the invoice date of May 20, 2006. However, according to the invoice, the charges were for a transaction that occurred on May 16, 2006. This is the date that should be used as the service date, not the invoice date. Therefore, I have corrected the service period. With regard to the Signalcrafters invoice, PPL stated that two invoices were included in the voucher study for the same transaction. One invoice was the initial invoice submitted for payment, but was denied for some reason. The second invoice was a resubmission of the invoice for the same transaction which was then paid. Therefore, for purposes of calculation of the lag days I used the initial service associated with the initial invoice that was submitted and the payment date associated with the resubmitted invoice. I believe this better captures the length time to pay for the transaction.

The second category I changed is the Printing and Office Supplies expense. PPL included several credit card transactions for which it used a date which was generally two days after the transaction date. I have revised the lag days for printing and office supplies to reflect the transaction date as indicated by the invoice instead of the date chosen by PPL.

Tree Trimming expense is the third category that I changed. The adjustment I made was to remove all Asplundh transactions. According to PPL, Asplundh experienced billing problems for services it provided to PPL through September 2006. Since all invoices used in the voucher study were related to services through September 2006, I have removed them because they are not reliable, because of the billing problems, for use in measuring the normal payment pattern of the Company.

Finally, the lag days for Work by Outsiders expense was changed to remove transactions related to Henkels & McCoy, Inc. In PPL's calculation, it used the invoice date as the service period "because a work period is not specified on the invoice."[1] A sample invoice that was provided by PPL included several work requests at various stages of billing for each work request on the invoice. I believe the invoice as provided cannot be used for lead-lag purposes. The lead-lag study is supposed to measure the date from receipt of service to payment of the service. If the invoice selected does not provide the date the service was received, it should not be used in the lag day calculation because it excludes a critical data needed for the calculation. Hence, I have removed these invoices from the lag day calculation.

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[1] Response to OTS-RE-114D.

Q. WHAT IS THE IMPACT OF YOUR ADJUSTMENTS TO THE LEAD LAG STUDY?

A. The combined effect of my working capital adjustments results in a $6.3 million decrease to Pennsylvania jurisdictional rate base. The adjustment to cash working capital is summarized on Schedule LKM-6, page 1.

Revenue Adjustments

Miscellaneous Revenues

Q. PLEASE EXPLAIN WHY YOU ARE PROPOSING AN ADJUSTMENT TO MISCELLANEOUS REVENUES.

A. Miscellaneous revenues are ancillary revenues that are not directly derived from the sale of energy. The major types of revenues in this category are: Reconnection Fees, NSF Fees, Service Charges, Temporary Facilities and the Alliance Agreement. During the historic test year PPL reported $369,431 of miscellaneous revenues. While the Company has received miscellaneous revenues over the last three years, it did not include any in its future test year cost of service. PPL claims that miscellaneous revenues are unplanned, so it has not included any specific projection in its future test year cost of service.

Despite the Company's assertion, I do not believe it is reasonable to fail to include any miscellaneous revenues in the cost of service. From a ratemaking perspective, these are recurring revenues that are received by the Company that help cover expenses. Therefore, to ignore these revenues in the cost of service would be inappropriate. Moreover, from 2004 to 2006, reconnection fees have increased from $70,246 to $245,501, or 249 percent. NSF fees have increased from $127,104 to $139,180 and the alliance agreement revenues have increased from $30,000 to $276,251. Even though there are offsets to these revenues in the Miscellaneous Revenues account because of items such as temporary facilities, the net revenues have grown during this period from a debit amount $24,065 (negative revenues) to $369,431. Therefore, I am proposing an adjustment to include miscellaneous revenues in the cost of service.

Q. HOW DID YOU CALCULATE YOUR ADJUSTMENT?

A. I calculated my adjustment by using the actual 2006 amount of $369,000 as the going level revenue amount. Although a growth rate could have been calculated based on the 3-year period 2004-2006, the use of the significant increases between 2004 and 2006 would result in growth rates that are not likely to be sustained. Part of the reason for the large increases in revenues from 2004 to 2006 is the passage of the Responsible Utility Customer Protection Act, known as Chapter 14. The effect of this law caused significant increases in the reconnection fees for PPL and other utilities operating in Pennsylvania. In order not to overstate the increase in these revenues, I used a conservative approach by using the actual 2006 amount. The change in the law not only explains why there is such a significant increase in the revenues, but it lends credence to my position that these are normal recurring revenues that PPL will receive in the future.

On Schedule LKM-7, page 1, I present my adjustment to increase miscellaneous revenues by $369,000.

Forfeited Discounts

Q. PLEASE EXPLAIN YOUR ADJUSTMENT TO FORFEITED DISCOUNTS.

A. Forfeited discounts are late payment fees collected by the Company from customers. In PPL's last rate case (Docket No. R-00049255), the Commission found it to be reasonable to use a formula based on a 3-year weighted average of actual late payment revenue to revenue from electricity sales. PPL has used this approach to derive its Forfeited Discounts revenues of $8,923,000. However, the Company used the 2003 through 2005 period to derive its average. I have used this same approach, but have updated the 3-year period that ends in 2006, the historic test year. This results in an adjustment to Forfeited Discounts that increased the amount included by the Company in the cost of service by $898,000. I believe it is more appropriate to use the most recent period which includes the historic test year in this proceeding. This adjustment is presented on Schedule LKM-8.

Rent from Electric Property

Q. WHAT ADJUSTMENT HAVE YOU MADE TO RENT FROM ELECTRIC PROPERTY?

A. In PPL's future test year, it has projected a decrease in rent from electric property. According to the Company, it is projecting a decrease because the test year rent revenues included non-recurring items. However, the data show that even if the non-recurring items are removed, rent from electric property would still have grown over the 2004 to 2006 period. Therefore, I am proposing an adjustment to reflect the growth trend in rent from electric property.

Q. HOW DID YOU CALCULATE YOUR ADJUSTMENT?

A. I calculated my adjustment by first calculating the growth rate for the 2005-2006 period. This period was used instead of the 3-year period 2004-2006 because Facilities Rent increased from $0 to $7.6 million between 2004 and 2005. If the 2004-2005 increase in Facilities Rent were included in the growth rate calculation, it would result in a much higher rate which I do not believe exists. Instead, I am using the 2005-2006 growth rate to be conservative in deriving the level of additional revenues I am including in the cost of service. Given that PPL had indicated that its 2006 rent revenues contained non-recurring items, I removed the non-recurring revenues from the 2006 revenue before applying the growth rate in order to avoid overstating the level of revenue. As a result, no non-recurring revenues are included in the adjusted revenues that I have included in the cost of service. This adjustment is presented on Schedule LKM-9, and it increases revenues by $2.6 million.

Expense Adjustments

Employee Expenses

Q. WHY HAVE YOU ADJUSTED EMPLOYEE EXPENSES?

A. PPL has included employee expenses of $1.2 million in the cost of service. According to the Company, this amount includes $900,000 for employee expenses such as mileage, parking fees, meals and miscellaneous out-of-pocket expenses, and $300,000 for employee relocations. The concern I have with the projected level of these expenses is twofold. First, during 2006, the Company recorded $500,000 for employee expenses related to mileage, parking fees, meals and miscellaneous out-of-pocket expenses. However, in explaining the increased budgeted levels, PPL indicates that the $500,000 was escalated to $600,000 for the 2007 budget, and then an additional $300,000 for such expenses related to offsite seminars and conferences was added. In response to OCA-VI-14, PPL states that during 2006 employees did attend off site seminars and conferences and those costs were included in the $500,000 on which the $600,000 included in the 2007 budget was based. The Company has not offered a satisfactory reason for the need for the additional $300,000 of expense. Therefore, I believe these costs should be removed from the cost of service.

The second concern involves employee relocation costs. Included in the total $1.2 million that that PPL is projecting for employee expenses is an increase of $200,000 in employee relocation expense over the historic test year level of $100,000. The

Company explains this increase as being caused by the relocation of a new vice president and general manger. The relocation costs related to the hiring of employees at this level is not a normal recurring event. If it were, the 2006 operating results would have reflected relocation costs at this level. Also the 2006 level of costs is consistent with 2005 and 2004. Therefore, I believe the costs comprising the $200,000 increase are non-recurring costs that should be removed from the cost of service.

On Schedule LKM-10, I present my adjustment to employee expenses, which reduces the cost of service by $449,000.

Telephone and Leased Wires

Q. WHAT ADJUSTMENT ARE YOU RECOMMENDING FOR TELEPHONE AND LEASED WIRES EXPENSE?

A. PPL increased its telephone and leased wires expense by $400,000 in the 2007 budget used as the cost of service in this proceeding. The reason cited by PPL for this increase is the need for additional lines due to the distribution rate case filing. However, when asked to produce documentation to substantiate its claim, the Company's response suggests that the cost increase was based on an assumption that additional call coverage would be needed for a temporary period of eight-months.

I am proposing an adjustment to remove these costs from O&M expenses because they are non-recurring temporary costs and unsupported. On Schedule LKM-11, I remove the $400,000 from the cost of service.

Advertising Expense

Q. PLEASE EXPLAIN YOUR ADJUSTMENT TO ADVERTISING EXPENSE.

A. The Company increased the test year expense in Account 909 (Information and Instructional Advertising) by $4.4 million. According to the Company, the funds will be used for consumer education programs related to conservation programs and the Meter Data Management System (MDMS) program. As a result of MDMS, there will be usage data available to customers that will allow them to better understand their electricity usage. The Company has included the $4.4 million as if it will be a normal ongoing expense. The largest component of those costs is $3.3 million allocated to television advertising. To put it in the proper perspective, the $3.3 million is significant because between 2002 and 2006, there was only one year (2003) when advertising expense exceeded $1.0 million, and the $3.3 million exceeds those costs by over $1.2 million. In fact, during that period advertising expenses were generally at or below the $500,000 level.

The Company states that the $4.4 million is being spent to introduce customers to the customer interface component of the MDMS.[2] The Company also agrees that after the introduction, those costs will no longer be incurred. Therefore, I do not believe that the Company will continue television advertising at the $3.3 million level as the ongoing level of expenses. In fact, in the response to OCA VII-13, the Company states only that it anticipates spending at the $3 million level, and does not provide any budget amounts for 2008 and 2009. Moreover, in the Business Case developed for the MDMS, implementation costs will not be incurred after 2007, and the only costs to be incurred in 2008 through 2010 are for customer care and computer related costs. The customer care

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[2] Mr. Krall's direct testimony, page 16, lines 10 to 15.

costs do not equate to $4.4 million annually, so it is clear that level of spending is not anticipated.

Q. WHAT ADJUSTMENT ARE YOU PROPOSING TO ADVERTISING EXPENSE?

A. There are two adjustments I am proposing to make to advertising expense. The first adjustment is to normalize the $3.3 million television advertising component of the $4.4 million over a 3-year period. This adjustment normalizes the television advertising component while leaving other components of advertising expense at the 2007 budget level. Hence, I have allowed for additional expenditures related to conservation. The second adjustment removes the $400,000 PPL included in the cost of service for institutional advertising. The Commission has a long-standing practice of not allowing institutional advertising in rates. Institutional advertising is focused on corporate image and does little to benefit the customers. On Schedule LKM-12, I present this adjustment to reduce O&M expenses by $2.6 million.

Q. ARE THERE ANY OTHER FACTORS THAT ALLOW YOU TO BELIEVE YOUR ADJUSTMENT IS REASONABLE?

A. Yes. Cost savings associated with MDMS have not been fully reflected in the cost of service. Future cost savings can be allocated to future advertising costs.

Materials and Supplies Expense

Q. WHAT ADJUSTMENT ARE YOU PROPOSING TO MATERIALS AND SUPPLIES EXPENSE?

A. In PPL's budget, it increased Materials and Supplies expense by $1.324 million. The Company explains the increase as being caused primarily by the need to repair distribution plant and the effect of materials and supplies being returned to inventory.

According to the Company, $800,000 of the future test year increase is related to the repair and replacement of non-capital substation equipment. However, a review of the budgets for 2008 and 2009 reveals a budget level more in line with the 2006 expense. Consequently, I believe the projected increase of $800,000 is due to non-recurring events and that the total expense is not representative of the normal ongoing level of expenses. Therefore, on Schedule LKM-13, I present my adjustment to reduce O&M expense by $799,000.

Pension Expense

Q. WHY HAVE YOU ADJUSTED PENSION EXPENSE?

A. The pension expense that PPL included in the cost of service is based upon the budgeted total pension costs of $28 million for the PPL Retirement Plan and $7.5 million for the PPL Supplemental Executive Retirement Plan (SERP). I requested the Company's most recent actuarial reports for it pension plans, and I am recommending that the pension expense that is included in the cost of service be based upon the Company's most recent actuarial studies.

Q. PLEASE EXPLAIN WHY FUNDS FROM THE BLACK LUNG TRUST HAVE BEEN INCORPORATED IN YOUR ADJUSTMENT TO PENSION EXPENSE.

A. The Black Lung Trust Fund was created in the 1980s by Pennsylvania Mines Corporation (a subsidiary of the former PP&L Company, the Company's predecessor) pursuant to the Black Lung Benefits Revenue Act of 1977 (the 1977 Act). The Black Lung Trust established a trust fund from which to pay the claims of Pennsylvania Mines Corporation's coal mine workers that are eligible to receive benefits under the 1977 Act. In August 2006, President Bush signed into law a provision that would allow excess trust fund assets to be used to pay accident and health benefits for insurance covering retired coal miners and their dependents. PPL's (the electric utility) pension expense is derived from an allocation of PPL Corporation's (the parent company) pension plan, which also covers retired employees of Pennsylvania Mines Corporation. The pension plan received payments from the Black Lung Trust during 2006 which had an effect on PPL Electric's pension expense. For 2006, PPL reported negative pensions and benefits expense because of a credit from the Black Lung Trust. PPL has indicated that the pension plan will receive $4.0 million annually from the Black Lung Trust. Since there is one pension plan that covers all workers, the $4.0 million is going to reduce the pension plan cost just as reflected in the Company's operating results for 2006. Therefore, in my pension expense calculation, I have reflected the $4.0 million reduction as well.

Q. HOW DID YOU CALCULATE YOUR ADJUSTMENT TO PENSION EXPENSE?

A. My adjustment to pension expense for the PPL Retirement Plan is based upon the Company's most recent actuarial study which was dated March 2007. I used the total pension cost of $25,966,337 and subtracted the $4,000,000 from the Black Lung Trust. For the SERP, the most recent amount from an actuarial study was the 2006 fiscal year amount, which I have used in my calculation. The 2006 amount was used because I believe that it is appropriate to use only the most recent actuarial amounts rather than budgetary estimates. These amounts were allocated to PPL Electric Utilities level and then I applied the O&M ratio to derive the expense amount. On Schedule LKM-14, I present this adjustment which reduces O&M expenses by $1.2 million.

Postretirement Benefits Other Than Pension Expense

Q. WHY HAVE YOU ADJUSTED POSTRETIREMENT BENEFITS OTHER THAN PENSION EXPENSE?

A. PPL included postretirement benefits other than pension based upon a budgeted cost of $36 million. As is the case with pension expense, PPL Electric Utilities postretirement benefits other than pension expense is an allocation of PPL Corporation's postretirement benefits plan. Postretirement benefits in an actuarially determined expense and the ratemaking allowance should be based upon an actuarial study and not on an amount projected for budgeting purposes. Accordingly, I am proposing to adjust this expense to reflect the most recent postretirement benefit study available, which is for the test year 2006. Therefore the adjustment I am recommending removes the budgeted postretirement benefit cost and replaces it with the amount from the most recent actuarial study. On Schedule LKM-15, I reduce postretirement benefits expense by $362,000 to reflect the most recent actuarial study.

Property Insurance Expense

Q. PLEASE EXPLAIN YOUR ADJUSTMENT TO PROPERTY INSURANCE EXPENSE.

A. PPL included $7,973,000 in the test year for Account No. 924, Property Insurance Expenses. PPL explained that $7,973,000 is made up of $7,560,000 for its storm insurance policy and $413,000 related to an allocation from the 2007 budget. I do not believe the budget allocation of $413,000 is valid. Therefore, the adjustment I am proposing removes the $413,000 from the cost of service.

Q. PLEASE EXPLAIN WHY YOU BELIEVE THE ADDITIONAL $413,000 BUDGET AMOUNT IS NOT VALID.

A. As explained by PPL, the Company budgets are based on the category of expense rather than FERC accounts. According to the Company, after the budget is developed, costs are allocated to FERC accounts where the budgeted expense category is identifiable to specific FERC accounts. Any remaining budgeted costs are then allocated to FERC accounts based upon each account's relationship to total O&M expense on an actual basis for the historic test year.[3] Based upon the Company's description, only the storm insurance expense should have been included in Account 924. The storm insurance policy is a new cost that the Company only began to incur in 2006, and it is clearly a cost that is specifically eligible to be recorded in account 924. In fact, it was the only cost included in that account during 2006. Prior to 2006 (2003 through 2005), there were no costs recorded in Account 924. Hence, there is no basis on which to include additional costs in this account. Therefore, I have removed the $413,000 from that account on Schedule LKM-16.

Storm Insurance Expense

Q. PLEASE EXPLAIN YOUR ADJUSTMENT TO STORM INSURANCE EXPENSE.

A. In June 2006, the Company acquired insurance coverage for damage sustained from storms. Under the insurance policy, PPL pays an annual premium of $7.5 million, with a deductible of $5.0 million per occurrence, or $7.5 million for all storms. The insurance coverage limits are $15.0 million per storm, or $20 million for all storms during the year. In the testimony of company witness Krall, he explains the benefits of the storm insurance as follows:

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[3] Direct testimony of J.R. Schadt, page 14.

> During 2005, the Company incurred $23.8 million in storm-related costs with the largest single storm being the ice storm event at $20.3 million. Assuming, for the purposes of this illustration, that the coverage was in place from January 1, 2005 to January 1, 2006. The ice storm would have been the first event and would have satisfied the single occurrence deductible of $5 million. Primary coverage would then have provided $11.1 million (or $15.3 million less the $4.2 million associated with capital and regular pay and benefits). The remaining $3.5 million in storm-related costs reflects several small storms. The Company would have been responsible for the first $2.5 million under the annual deductible. The remaining $1 million, less capital and regular wages and benefits, would have been covered by PPL Power. In this example, there would have been no need for the Company to petition the Commission for approval to defer for accounting purposes or to pursue recovery of extraordinary costs. Customers would have paid a $5.7 million premium and, in exchange, received $12.1 million in storm restoration benefits.

Q. DO YOU AGREE WITH MR. KRALL'S ANALYSIS?

A. No, because the ratepayer cost is actually higher than Mr. Krall indicates. The insurance acquired by the Company is provided in two layers. The first layer is provided by an affiliate, PPL Power Insurance. The annual premium for that layer is $6.0 million. The second layer is provided by two reinsurers, Ariel Re and ACE Bermuda. The annual premium for that layer is $1,560,000. The total insurance is, therefore, $7.650 million. In addition to the insurance premiums, PPL has included $7.5 million in the cost of service for normal storm damage costs, (in 2005, the Company collected $7.0 million in storm damage costs from customers). Using Mr. Krall's example, customers would have paid approximately $15.0 million for $12.1 million of insurance coverage. Simply said, the insurance acquired by PPL is not beneficial to customers because of the high premium, high deductible and low coverage limit. In essence, PPL is requesting the Commission to allow it to pre-collect storm damage costs and give it to an affiliate to invest[4] (one of the functions of insurance companies is to invest premiums) while

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[4] The function of insurance companies is to invest premiums. In the response to OCA I-58, the Company indicates that PPL Power Insurance is in the process of building a reserve.

increasing costs to its customers. By PPL's own admission, storm damage insurance has not been an economically successful prospect. In the response to OCA I-58(d) PPL stated "[h]istorically, primary commercial insurance companies have been reluctant to provide storm damage coverage for transmission and distribution lines at reasonable costs and deductibles." It is important to note that when it came to establishing the premium that PPL Power Insurance charges PPL Electric Utilities for storm damage insurance, PPL Power Insurance asked insurance companies to provide estimates of the premiums they would have charged if they were willing to underwrite the insurance themselves, and then used the premium data they were provided to set the premium PPL Electric Utilities is currently charged. Hence, it appears that the Company has chosen to take part in a transaction with an affiliate that it considered unreasonable when dealing with non-affiliates. As a result of the foregoing, I believe the storm damage insurance is not in the benefit of customers, and should not be included in the cost of service.

Q. WHAT ADJUSTMENT HAVE YOU MADE TO STORM DAMAGE INSURANCE EXPENSE?

A. I am proposing an adjustment remove the $7.5 million storm damage insurance expense from the cost of service on Schedule LKM-17.

Amortization of Negative Net Salvage

Q. PLEASE EXPLAIN YOUR ADJUSTMENT TO THE AMORTIZATION OF THE NEGATIVE NET SALVAGE.

A. The Company has included the amortization of negative net salvage based on four years of historical data and one year of projected data. Counsel has advised me that the Commission has an established precedent of allowing the net salvage based on five years of historical data rather than the inclusion of projected data. Therefore I believe it is necessary to adjust the net salvage claim to reflect the most recent five years of historical data. This adjustment is presented on Schedule LKM-18, and it reduces expenses by $592,000.

Capital Stock Tax

Q. PLEASE EXPLAIN YOUR ADJUSTMENT TO THE CAPITAL STOCK TAX EXPENSE.

A. The Company included $2.9 million as the budgeted level of capital stock tax expense for the test period. The $2.9 million is based upon the capital stock tax formula as provided in Pennsylvania Corporate Tax Report Form. The capital stock tax is being phased out through 2010. Over the next three years, there will be a 1 mill reduction in the tax rate in each year. Hence during 2008, the rate will be 2.89 mills instead of the current 3.89 mills. Therefore, I have calculated the capital stock tax based upon the capital stock tax rate of 2.89 mills, which is the rate that will be applicable during the rate effective period.

On Schedule LKM-19, I present this adjustment which reduces Taxes Other Than Income by $641,000.

Q. ARE THERE ANY OTHER ISSUES RELATING TO THE CAPITAL STOCK TAX THAT YOU WOULD LIKE TO DISCUSS?

A. Yes. In PPL's filing, it included the capital stock tax in the revenue requirement gross-up factor. As a result, the revenue requirement sought by PPL included an additional $226,000. In my presentation of the revenue requirements, I have removed the capital stock tax from the gross-up factor. Given that I have included the 2007 net income in the capital stock tax calculation, the effect of the rate increase has been reflected. Therefore, the revenue gross-up factor should not include a component for the capital stock tax. By removing the capital stock tax from the gross-up factor, I have reduced the revenue requirement by $226,000.

It should be noted that in the PPL Gas Utilities case at Docket No. R-00061398, the Commission found that the Capital Stock Tax should not be included in the revenue gross-up factor and that it is appropriate to reflect the capital stock tax rate for the rate effective period.

Interest Synchronization

Q. PLEASE EXPLAIN YOUR INTEREST SYNCHRONIZATION ADJUSTMENT.

A. To determine the tax-deductible interest for ratemaking, I have multiplied the adjusted rate base by the weighted cost of debt included in the capital structure. This procedure synchronizes the interest deduction for tax purposes with the interest component of the return on rate base to be recovered from ratepayers. As shown in Schedule LKM-20, this adjustment decreases the interest deduction by $265,000 compared to the interest deduction recognized by PPL in its filing. This increases state and federal income taxes by $26,000 and $84,000, respectively.

Energy Efficiency Rider

Q. THE COMPANY HAS PROPOSED A RIDER TO RECOVER ITS ENERGY EFFICIENCY PROGRAM-RELATED COSTS. WOULD YOU PLEASE COMMENT?

A. PPL has proposed a mechanism called the Energy Efficiency Rider (EER) to recover the costs incurred under its energy efficiency program to residential and small commercial customers. The Company proposes to compute the annual rider by estimating the program costs annually which would be added to the bills of customers taking service under Rate Schedules RS, RTS, RTD and GS-1. At the end of each 12-month period, the Company plans to identify any under- or over-collections which would be collected from or refunded to customers with interest. The program costs will be costs that will be under the Company's control. There is no evidence to suggest that there will be large fluctuations in costs that are beyond the Company's control that puts it at financial risk. Therefore, these costs are normal period costs that should be part of base rates and not separately collected through a rider. For these reasons and those also discussed by OCA witness Galligan, I recommend that the Commission not accept the Company's proposal to include these costs in a separate rider.

Rider Recovery

Q. ARE THERE ANY OTHER RIDER RELATED ISSUES?

A. Yes. In both my testimony and that of OCA witness Colton and OCA witness Galligan, recommendations are made to move certain expenses out of a Rider and into base rates for recovery purposes. For the purposes of this testimony, however, I have shown my distribution base rate revenue requirement on a basis comparable to the Company's presentation. The final distribution base rate revenue requirement will need to reflect the inclusion of any expenses that are moved from Rider recovery to base rate recovery.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

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BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

PPL ELECTRIC UTILITIES)
CORPORATION) DOCKET NO. R-00072155

SCHEDULES ACCOMPANYING THE DIRECT TESTIMONY OF LAFAYETTE K. MORGAN, JR.

ON BEHALF OF THE

OFFICE OF CONSUMER ADVOCATE

JULY 2007

EXETER
ASSOCIATES, INC.
5565 Sterrett Place
Suite 310
Columbia, Maryland 21044

Docket No. R-00072155
Schedule LKM-1
Page 1 of 2

PPL ELECTRIC UTILITIES CORPORATION

Summary of Operating Income
For the Test Year Ended December 31, 2007
($000)

	PAPUC Jurisdictional Amount per Co.	OCA Cost of Service Adjustments	Amount After Adjustments	OCA Recommended Change In Revenue	After Proposed Rate Increase
Operating Revenues	$ 664,695	$ 2,990	$ 667,685	$ 34,444	$ 702,129
Late Payment Revenue	8,923	898	9,821	116	9,937
Total Operating Revenues	$ 673,618	$ 3,888	$ 677,506	$ 34,560	$ 712,066
Operating Expenses					
O&M Expenses	$ 339,555	$ (11,963)	$ 327,592	$ 276	$ 327,868
Depreciation & Amortization Expenses	111,825	(530)	111,295	-	111,295
Taxes Other Than Income	49,849	(566)	49,283	2,039	51,322
Current State Income Tax	9,599	1,719	11,318	3,221	14,539
Current Federal Income Tax	32,452	5,422	37,874	10,158	48,032
Deferred Income Taxes	8,378	-	8,378	-	8,378
Investment Tax Credit	(1,673)	-	(1,673)	-	(1,673)
Total Operating Expenses	$ 549,985	$ (5,919)	$ 544,066	$ 15,694	$ 559,760
Net Operating Income	$ 123,633	$ 9,807	$ 133,440	$ 18,866	$ 152,306
Rate Base	$ 2,022,969		$ 2,014,632		$ 2,014,632
Return On Rate Base	6.11%		6.62%		7.56%

PPL ELECTRIC UTILITIES CORPORATION

Summary of Revenue Increase at OCA Rate of Return
For the Test Year Ended December 31, 2007
($000)

		Amount	
Adjusted Rate Base		$ 2,014,632	Schedule LKM-2, Page 2
Required Rate of Return		7.560%	
Net Operating Income Required		$ 152,306	
Net Operating Income at Present Rates		133,440	Schedule LKM-1, Page 1
Income Deficiency/(Surplus)		$ 18,866	
Revenue Multiplier		1.83186	
Required Change in Company Revenue		$ 34,560	
Proposed Revenue Change		$ 34,560	
Uncollectibles	0.80%	276	
Gross Revenues Tax	5.90%	2,039	
Subtotal		$ 32,245	
State Income Tax	9.99%	3,221	
Subtotal		$ 29,024	
Federal Income Tax	35.00%	10,158	
Net Income Increase Required		$ 18,866	

Docket No. R-00072155
Schedule LKM- 2
Page 1 of 2

PPL ELECTRIC UTILITIES CORPORATION

Summary of Rate Base
For the Test Year Ended December 31, 2007
($000)

	PAPUC Jurisdictional Amount per Co.	OCA Rate Base Adjustments	Amount After Adjustments
Total Plant in Service	$ 3,848,933	$ -	$ 3,848,933
Accumulated Depreciation	(1,464,244)	-	(1,464,244)
Net Plant in Service	$ 2,384,689	$ -	$ 2,384,689
Cash Working Capital	$ 18,702	$ (6,335)	$ 12,367
Materials & Supplies	24,250	-	24,250
Plant Held For Future Use	2,002	(2,002)	-
Customer Advances	(269)	-	(269)
Customer Deposits	(15,950)	-	(15,950)
Accumulated Deferred Income Taxes	(390,455)	-	(390,455)
Total Rate Base	$ 2,022,969	$ (8,337)	$ 2,014,632

PPL ELECTRIC UTILITIES CORPORATION

Summary of Rate Base Adjustments
For the Test Year Ended December 31, 2007
($000)

	Source	PAPUC *Jurisdictional* Amount per Co.
Rate Base per Company Filing	Schedule LKM-2, Page 1	$ 2,022,969
OCA Adjustments:		
Plant Held For Future Use	Schedule LKM-5	$ (2,002)
Cash Working Capital	Schedule LKM-6, Page 1	(6,335)
Total Ratemaking Adjustments		$ (8,337)
Adjusted Rate Base per OCA		$ 2,014,632

Docket No. R-00072155
Schedule LKM-3
Page 1 of 2

PPL ELECTRIC UTILITIES CORPORATION

Summary of Adjustments to Net Income
For the Test Year Ended December 31, 2007
($000)

	Total Company Amount
Net Income per Company	$ 123,633
OCA Adjustments:	
Reflect Miscellaneous Revenues	$ 203
Annualize Forfeited Discount Revenues	495
Annualize Rent from Electric Property Revenues	1,533
Remove Excess Employee Expenses	263
Normalize Telephone and Leased Wire Expense	234
Normalize Advertising Expense	1,527
Normalize Materials and Supplies Expense	467
Annualize Pension Expense	716
Annualize OPEB Expense	212
Annualize Property Insurance Expense	217
Remove Storm Insurance Expense	3,364
Normalize Negative Net Salvage	310
Normalize Capital Stock Tax	375
Interest Synchronization	(110)
Total Ratemaking Adjustments	$ 9,807
Total Adjusted Net Income per OCA	$ 133,440

PPL ELECTRIC UTILITIES CORPORATION

Summary of Adjustments to Net Income
For the Test Year Ended December 31, 2007
($000)

	Operating Revenues	O&M Expenses	Depreciation & Amortization Expenses	Taxes Other Than Income	Current State Income Taxes	Current Federal Income Tax	Deferred Income Taxes	Investment Tax Credit	Net Operating Income
PA Jurisdictional Amount per Company	$ 673,618	$ 339,555	$ 111,825	$ 49,849	$ 9,599	$ 32,452	$ 8,378	$ (1,673)	$ 123,633
OCA Adjustments:									
Reflect Miscellaneous Revenues	$ 369	$ -	$ -	$ 22	$ 35	$ 109	$ -	$ -	$ 203
Annualize Forfeited Discount Revenues	898	-	-	53	84	266	-	-	495
Annualize Rent from Electric Property Revenues	2,621	-	-	-	262	826	-	-	1,533
Remove Excess Employee Expenses	-	(449)	-	-	45	141	-	-	263
Normalize Telephone and Leased Wire Expense	-	(400)	-	-	40	126	-	-	234
Normalize Advertising Expense	-	(2,610)	-	-	261	822	-	-	1,527
Normalize Materials and Supplies Expense	-	(799)	-	-	80	252	-	-	467
Annualize Pension Expense	-	(1,224)	-	-	122	386	-	-	716
Annualize OPEB Expense	-	(362)	-	-	36	114	-	-	212
Annualize Property Insurance Expense	-	(370)	-	-	37	116	-	-	217
Remove Storm Insurance Expense	-	(5,749)	-	-	574	1,811	-	-	3,364
Normalize Negative Net Salvage	-	-	(530)	-	53	167	-	-	310
Normalize Capital Stock Tax	-	-	-	(641)	64	202	-	-	375
Interest Synchronization	-	-	-	-	26	84	-	-	(110)
Total Ratemaking Adjustments	$ 3,888	$ (11,963)	$ (530)	$ (566)	$ 1,719	$ 5,422	$ -	$ -	$ 9,807
Total Adjusted Income	$ 677,506	$ 327,592	$ 111,295	$ 49,283	$ 11,318	$ 37,874	$ 8,378	$ (1,673)	$ 133,440

Docket No. R-00072155
Schedule LKM-4

PPL ELECTRIC UTILITIES CORPORATION

Reconciliation of Current State and Federal Income Taxes
For the Test Year Ended December 31, 2007

		Test Year *Per Company*	Ratemaking *Adjustments*	Test Year at Present *Rates*	Increase at OCA *Rate of Return*	After Proposed Increase
CALCULATION OF COMBINED CURRENT INCOME TAX						
Net Operating Income Before Income Taxes		$ 165,684	$ 16,948	$ 182,632	$ 32,245	$ 214,877
Adjustments for Income Taxes (Including Interest)		(61,281)	265	(61,016)	-	(61,016)
Subtotal		$ 104,403	$ 17,213	$ 121,616	$ 32,245	$ 153,861
Special Tax Deductions		(8,320)	-	(8,320)	-	(8,320)
State Taxable Income		$ 96,083	$ 17,213	$ 113,296	$ 32,245	$ 145,541
State Income Tax	9.99%	$ 9,599	$ 1,720	$ 11,318	$ 3,221	$ 14,540
Federal Taxable Income Before State Income Tax		$ 104,403	$ 17,213	$ 121,616	$ 32,245	$ 153,861
State Income Tax		$ 9,599	$ 1,720	$ 11,318	$ 3,221	$ 14,540
Federal Taxable Income		$ 94,804	$ 15,493	$ 110,298	$ 29,024	$ 139,321
Federal Income Tax	35.00%	33,182	5,423	38,604	10,158	48,762
Consolidated Tax Adjustment		(616)	-	(616)	-	(616)
Federal Tax Credits		(114)	-	(114)	-	(114)
Net Federal Income Tax		$ 32,452	$ 5,423	$ 37,874	$ 10,158	$ 48,032
Net Combined Current Income Tax		$ 42,050	$ 7,142	$ 49,192	$ 13,380	$ 62,572
Total Combined Current Income Taxes (Schedule LKM-1, Page 1)		42,051	7,141	49,192	13,379	62,571
Unreconciled/Rounding		$ (1)	$ 1	$ 0	$ 1	$ 1

Docket No. R-00072155
Schedule LKM-5

PPL ELECTRIC UTILITIES CORPORATION

Adjustment to Remove Plant Held For Future Use
For the Test Year Ended December 31, 2007
($000)

	PAPUC Jurisdictional Amount 1/
Total Distribution Plant Held For Future Use Included in Rate Base	$ 2,002
Adjustment to Rate Base	$ (2,002)

Notes:
1/ Exhibit Future 1, C-1.

PPL ELECTRIC UTILITIES CORPORATION

Adjustment to Allowance for Cash Working Capital
For the Test Year Ended December 31, 2007
($000)

		Amount	
O&M Expense Cash Working Capital	$	8,271	1/
Average Prepayments		2,470	2/
Accrued Taxes		16,595	3/
Interest Payments		(8,915)	4/
Preferred and Preference Dividends		9	5/
Total Cash Working capital requirement per OCA	$	18,430	
Total Cash Working capital requirement per Company		26,931	2/
Adjustment to Cash Working Capital	$	(8,501)	
PAPUC Jurisdictional Allocation Factor		74.52%	6/
Adjustment to Cash Working Capital	$	(6,335)	

Notes:
1/ Schedule LKM 6, Page 2.
2/ Exhibit Future 1, C-4, Page 1.
3/ Schedule LKM 6, Page 5.
4/ Schedule LKM 6, Page 6.
5/ Schedule LKM 6, Page 7.
6/ Calculated based on data presented on Exhibit JMK-2, Page 16, Line 9.

PPL ELECTRIC UTILITIES CORPORATION

O&M Allowance for Cash Working Capital
For the Test Year Ended December 31, 2007
($000)

		Amount	1/
Total Pro Forma O&M Expenses	$	553,025	
Less: Non-cash Items and Adjustments			
Uncollectibles		20,155	
On-Track Customer Assistance Expense		4,500	
Amortization of 2005 Ice Storm Cost		1,611	
Remove Excess Employee Expenses		500	
Normalize Telephone and Leased Wire Expense		400	
Remove Institutional Advertising from Account 909		400	
Normalize Materials and Supplies Expense		800	
Adjustment to Pension Expense		2,157	
Adjustment to Postretirement Benefits Expense		627	
Annualize Property Insurance Expense		413	
Remove Storm Insurance Expense		7,560	
Total Reductions from Working Capital Base		39,123	
Pro Forma O&M Expenses for Cash Working Capital	$	513,902	
Daily O&M Expense	$	1,408	
Average Revenue Lag Days		45.20	2/
Average O&M Expense Lag Days		39.33	3/
Average Net Lag		5.87	
O&M Expense Cash Working Capital per OCA	$	8,271	

Notes:
1/ Exhibit Future C-4, Page 2.
2/ Revenue Lag Days per Exhibit Historic C-4, Page 2.
3/ Schedule LKM-6, Page 2.

PPL ELECTRIC UTILITIES CORPORATION

Calculation of O&M Expenses Lag
For the Test Year Ended December 31, 2007

	Amount 1/	Days Lags 1/	Dollar Days
Payroll	$ 87,338	12.00	$ 1,048,056
Employee Benefits	28,838	35.00	1,009,330
Affiliate Support Costs	94,519	35.00	3,308,165
Other Operating Expense	345,849	47.77 2/	16,521,006
Total O&M Expenses	$ 556,544		$ 21,886,557
Weighted Lag Days		39.33	

Notes:
1/ Exhibit Historic C-4, Page 2.
2/ Schedule LKM-6, Page 3.

PPL ELECTRIC UTILITIES CORPORATION

Calculation of Other Expenses Lag
For the Test Year Ended December 31, 2007

	Amount 1/	Days Lags 1/	Dollar Days
Employee Expenses	$ 562,871	12.00	$ 6,754,452
Materials & Supplies	488,233	37.37 2/	18,245,061
Printing & Office Supplies	161,382	38.69 3/	6,243,637
Tree Trimming	7,282,572	57.03 4/	415,311,621
Work by Outsiders	7,581,220	80.35 5/	609,134,561
Services	1,537,331	20.91	32,145,591
Postage	1,319,124	(7.01)	(9,247,059)
Telephones & leased Wires	908,779	35.12	31,916,318
Rents	3,438,660	17.74	61,001,828
Advertising	66,462	36.93	2,454,442
Miscellaneous	1,554,308	10.00	15,543,080
Adjustment to O&M Expenses	$ 24,900,942		$ 1,189,503,532
Weighted Lag Days		47.77	

Notes:
1/ Attachment II-B-4, Page 4.
2/ Schedule LKM-6, Page 4.
3/ Schedule LKM-6, Page 5.
4/ Schedule LKM-6, Page 6.
5/ Schedule LKM-6, Page 7.

PPL ELECTRIC UTILITIES CORPORATION

Accrued Taxes
For the Test Year Ended December 31, 2007

	Amount	12-Month Accrued Factor 1/	Accrued Taxes
Federal Income Tax	$ 69,135	-3.82%	$ (2,641)
PA Income Taxes	20,872	-1.74%	(363)
PA Gross Receipts Tax	52,291	35.76%	18,699
PA Capital Stock Tax	2,271	-1.74%	(40)
PA Public Utility Realty Tax	4,039	23.26%	939
Total Accrued Taxes			$ 16,595

Notes:
1/ Exhibit Future C-4, Page 4.

PPL ELECTRIC UTILITIES CORPORATION

Interest Payments
For the Test Year Ended December 31, 2007

		Amount
Total Company Rate Base	$	2,637,137
Weighted Cost of Debt		2.75%
Pro forma Interest Expense	$	72,521
Daily Interest Expense	$	199
Net Interest Lag Days		44.80
Total Accrued Taxes	$	8,915

Notes:
1/ Exhibit Future C-4, Page 4.

PPL ELECTRIC UTILITIES CORPORATION

Preferred and Preference Dividends
For the Test Year Ended December 31, 2007

	Accrued Taxes
Total Company Rate Base	$ 2,637,137
Weighted Cost of Debt	0.65%
Pro forma Interest Expense	$ 17,141
Daily Interest Expense	$ 47
Net Interest Lag Days	(0.20)
Total Accrued Taxes	$ (9)

Notes:
1/ Exhibit Future C-4, Page 4.

PPL ELECTRIC UTILITIES CORPORATION

Calculation of Materials Expense Lag
For the Test Year Ended December 31, 2007

	Voucher Number 1/	Invoice Number 1/	Mid Point of Service Period 1/	Payment Date 1/	Amount 1/	Lag Days 1/	Dollar Days
NOVA Electric	02407015	014183	6/30/06	7/31/06	$ 15,135.00	31	$ 469,185
RFL Electronics Inc	02402522	92499	6/29/06	7/31/06	13,690.00	32	438,080
TMC Industries	02408720	0611531RA	7/12/06	8/11/06	12,937.50	30	388,125
PENNSY SUPPLY	02382268	1511781	5/16/06 2/	7/17/06	2,166.00	62	134,292
Westgate Global Logistics	023969552	266607	6/22/06	7/13/06	1,050.00	21	22,050
Signalcrafters Tech Inc.	02432314/024314	3325/3334/	7/20/06 2/	9/14/06	26,800.00	56	1,500,800
GE Parts Super Center	02427683	884165399	8/8/06	9/7/06	24,890.73	30	746,722
G&W Electric Co	02433901	G93607	8/18/06	9/18/06	12,360.00	31	383,160
Dent Instruments	02395156	56585	6/14/06	8/2/06	8,388.00	49	411,012
Westgate Global Logistics	02434371	267156	8/21/06	9/5/06	2,750.00	15	41,250
Trenwa Inc.	02420553	20184	7/31/06	8/30/06	2,000.00	30	60,000
George S Coyne Chemical Co. Inc	02415660	700397	7/18/06	8/17/06	1,509.00	30	45,270
Pennsylvania Transformer	02432137	21073	8/18/06	9/25/06	5,500.00	38	209,000
MESA Technical Associates	02420553	1889	8/29/06	9/28/06	3,389.00	30	101,670
A TO S METALS INC	02451007	11812	8/18/06	9/27/06	1,251.00	40	50,040
					$ 133,816.23		$ 5,000,656
						37.37	

Notes:
1/ Attachment II-B-4, Page 4.
2/ Response to OTS-RE-111-D.

PPL ELECTRIC UTILITIES CORPORATION

Calculation of Printing & Office Supply Expense Lag
For the Test Year Ended December 31, 2007

	Voucher Number 1/	Invoice Number 1/	Mid Point of Service Period 1/	Payment Date 1/	Amount 1/	Lag Days 1/	Dollar Days
Credit Card Purchase		0000254574	6/15/06	7/29/06	$ 2,415.79	44	$ 106,295
GRAYBAR ELECTRIC CO Inc	02403100	918598037	6/29/06	7/31/06	1,975.63	32	63,220
Credit Card Purchase		0000252107	5/26/06	7/18/06	497.36	53	26,360
Credit Card Purchase		0000252107	5/26/06	7/18/06	432.21	53	22,907
Credit Card Purchase		0000255463	7/14/06	8/8/06	1,773.00	25	44,325
Alphagraphics	02410304	39159	7/13/06	9/13/06	450.00	62	27,900
Credit Card Purchase		00000256799	6/20/06	8/23/06	2,415.79	64	154,611
Credit Card Purchase		0000256774	7/17/06	8/17/06	- 2/	31	-
Credit Card Purchase		0000257867	7/14/06	8/29/06	557.76	46	25,657
Credit Card Purchase		0000257646	8/7/06	8/25/06	1,259.42	18	22,670
Credit Card Purchase		0000260621	9/8/06	9/26/06	1,315.18	18	23,673
EDS Corporation	02432226	u2045563	8/15/06	9/25/06	840.02	41	34,441
Credit Card Purchase		0000261563	9/12/06	9/30/06	630.45	18	11,348.10
					$ 14,562.61		$ 563,406
						38.69	

Notes:
1/ Attachment II-B-4, Page 5.
2/ Response to OTS-RE-112-D.

PPL ELECTRIC UTILITIES CORPORATION

Calculation of Tree Trimming Expense Lag
For the Test Year Ended December 31, 2007

	Voucher Number 1/	Invoice Number 1/	Mid Point of Service Period 1/	Payment Date 1/	Amount 1/	Lag Days 1/	Dollar Days
ASPLUNDH TREE EXPERT CO	02408597	175702	7/5/06	8/14/06	$ - 2/	40	$ -
ASPLUNDH TREE EXPERT CO	02408522	175705	7/5/06	8/14/06	- 2/	40	-
JAFLO INC	02419774	000931	6/21/06	8/21/06	46,000.50	61	2,806,031
JAFLO INC	02419774	000931	6/21/06	8/21/06	22,878.75	61	1,395,604
ASPLUNDH TREE EXPERT CO	02431283	27E052	8/9/06	9/20/06	- 2/	42	-
JAFLO INC	02419774	000931	6/21/06	8/21/06	8,915.50	61	543,846
JAFLO INC	02420237	000934	7/5/2006	8/28/06	5,883.62	54	317,715
ASPLUNDH TREE EXPERT CO	02431307	31E055	6/5/06	9/20/06	- 2/	107	-
ASPLUNDH TREE EXPERT CO	02446817	195033	5/6/06	10/10/06	- 2/	157	-
PNC Bank	02446427	31E056	7/31/06	9/25/06	83,228.12	56	4,660,775
JAFLO INC	02450680	000940	8/16/06	10/6/06	34,106.86	51	1,739,450
ASPLUNDH TREE EXPERT CO	02431313	195037	8/9/06	9/20/06	- 2/	42	-
ASPLUNDH TREE EXPERT CO	02431314	29E056	8/9/06	9/20/06	- 2/	42	-
ASPLUNDH TREE EXPERT CO	02431299	29E055	8/9/06	9/20/06	- 2/	42	-
ASPLUNDH TREE EXPERT CO	02431327	29E056	8/9/06	9/20/06	- 2/	42	-
ASPLUNDH TREE EXPERT CO	02431313	195037	8/9/06	9/20/06	- 2/	42	-
ASPLUNDH TREE EXPERT CO	02431314	29E056	8/9/06	9/20/06	- 2/	42	-
					$ 201,013.35		$ 11,463,420
						57.03	

Notes:
1/ Attachment II-B-4, Page 6.
2/ Response to OTS-RE-113-D.

PPL ELECTRIC UTILITIES CORPORATION

Calculation of Work By Outsiders Lag
For the Test Year Ended December 31, 2007

	Voucher Number 1/	Invoice Number 1/	Mid Point of Service Period 1/	Payment Date 1/	Amount 1/	Lag Days 1/	Dollar Days
Utilities International	02404750	PPLEUCBS2603	3/15/06	7/13/06	$ 30,683.80	120	$ 3,682,056
East Coast Drilling & Trenching	02398583	062206PPL31	6/22/06	7/24/06	24,999.00	32	799,968
HENKELS & MCCOY	02391791	PPLA06I1168	6/6/06	7/7/06	- 2/	31	-
The Trehab Center	02412633	60106	6/15/06	7/31/06	20,097.00	46	924,462
HENKELS & MCCOY	02379235	*PPLA06I1120*	*5/16/06*	*7/13/06*	- 2/	58	-
Duggan & Marcon	02406727	6161AA	7/11/06	8/10/06	16,500.00	30	495,000
Osmose Utilities Services	02355012	726300061	4/12/2006	7/26/06	15,219.37	105	1,598,034
KT Power	02407492	11485	5/18/06	7/27/06	12,482.74	70	873,792
HENKELS & MCCOY	02425895	PPLA06I1341	7/26/06	9/1/06	- 2/	37	-
Waste Management of PA	02428609	82530	7/5/06	9/11/06	13,594.11	68	924,399
AGROTORS INC	02429653	2006200127	8/4/06	9/11/06	13,500.00	38	513,000
Everhart & Hoover Power Line	02425123	0807063	7/29/06	9/6/06	11,648.71	39	454,300
Lineal Industries	02422657	248859	7/21/06	9/1/06	10,406.00	42	437,052
Miller Brothers	02331532	602003	3/8/06	9/14/06	68,691.00	190	13,051,290
HENKELS & MCCOY	02448612	*PPLA06I1451*	*9/6/06*	*10/6/06*	- 2/	30	-
Pavemasters	02446433	081506	8/15/06	10/4/06	35,793.00	50	1,789,650
AGROTORS INC	02449617	2006200134	9/13/06	10/16/06	28,350.00	33	935,550
The Trehab Center	02439242	80106	8/15/2006	10/2/2006	21,791.00	48	1,045,968
AGROTORS INC	02433924	200620029	8/16/2006	9/20/2006	21,600.00	35	756,000
HENKELS & MCCOY	02448751	*PPLA06I1449*	*9/6/2006*	*10/6/2006*	- 2/	30	-
HENKELS & MCCOY	02449587	PPLA06I1461	9/6/2006	10/6/2006	- 2/	30	-
D L Fry Inc.	02439841	I200658	9/1/2006	10/2/2006	10,779.36	31	334,160
					$ 356,135.09		$ 28,614,681
						80.35	

Notes:
1/ Attachment II-B-4, Page 7.
2/ Response to OTS-RE-114-D.

Docket No. R-00072155
Schedule LKM-7

PPL ELECTRIC UTILITIES CORPORATION

Adjustment to Reflect Miscellaneous Revenues
For the Test Year Ended December 31, 2007
($000)

	Jurisdictional Amount	
Total Historic Test Year Miscellaneous Revenues	$ 369	1/
Total Miscellaneous Revenues per Company	0	
Adjustment to Miscellaneous Revenues	$ 369	

Notes:
1/ Exhibit Historic 1, D-3, Page 1.

Docket No. R-00072155
Schedule LKM-8

PPL ELECTRIC UTILITIES CORPORATION

Adjustment to Annualize Forfeited Discount Revenues
For the Test Year Ended December 31, 2007
($000)

	Amount	
Total Sale of Electricity Revenues	$ 2,924,512	1/
3-Year Forfeited Discount Ratio	0.34%	2/
Annualized Forfeited Discount Revenues	$ 9,821	
Annualized Forfeited Discount Revenues Per Company	8,923	
Adjustment to Forfeited Discount Revenues	$ 898	

Notes:
1/ Exhibit Future 1, D-3, Page 1.
2/ Response to OTS-RE-32-D.

Docket No. R-00072155
Schedule LKM-9

PPL ELECTRIC UTILITIES CORPORATION

Adjustment to Annualize Rent from Electric Property Revenues
For the Test Year Ended December 31, 2007
($000)

	Amount	
2006 Rent from Electric Property Revenues	$ 32,041	1/
Remove Non-recurring Items		
Unauthorized pole Attachments	(650)	2/
Fiber Optic System Rent	(600)	2/
Recurring Rent from Electric Property Revenues	$ 30,791	
2005 -2006 growth rate	8.14%	3/
Annualized Rent from Electric Property Revenues	$ 33,297	
Annualized Rent from Electric Property Revenues per PPL	30,596	4/
Adjustment to Annualize Rent from Electric Property Revenues	$ 2,701	
PAPUC Jurisdictional Allocation Factor	97.05%	5/
Adjustment to Revenues	$ 2,621	

Notes:
1/ Exhibit Historic 1, B-3.
2/ Response to OCA VI-9.
3/ Data from Response to OTS -RE-46-D. Growth excludes non-recurring items of $1.25 million.
4/ Exhibit Future 1, B-3.
5/ Exhibit JMK-2, Page 26, Lines 10 & 11.

Docket No. R-00072155
Schedule LKM-10

PPL ELECTRIC UTILITIES CORPORATION

Adjustment to Remove Excess Employee Expenses
For the Test Year Ended December 31, 2007
($000)

	Amount	
Unusual Relocation Location Costs	$ 200	1/
Unsupported Employee Expenses	300	1/
Adjustment to T&D O&M Expenses	$ (500)	
PAPUC *Jurisdictional Allocation Factor*	89.83%	2/
Adjustment to O&M Expenses	$ (449)	

Notes:

1/ Response to OTS-RE-129.
2/ Calculated based on data presented on Exhibit JMK-2, Page 20, Line 5.

Docket No. R-00072155
Schedule LKM-11

PPL ELECTRIC UTILITIES CORPORATION

Adjustment to Normalize Telephone and Leased Wire Expense
For the Test Year Ended December 31, 2007
($000)

	Amount	
Non-Recurring Costs included in the Cost of Service	$ 400	1/
Adjustment to T&D O&M Expenses	$ (400)	
PAPUC Jurisdictional Allocation Factor	100.00%	
Adjustment to O&M Expenses	$ (400)	

Notes:
1/ Response to OTS-RE-129.

Docket No. R-00072155
Schedule LKM-12

PPL ELECTRIC UTILITIES CORPORATION

Adjustment to Normalize Advertising Expense
For the Test Year Ended December 31, 2007
($000)

	Amount	
Energy Conservation/Efficiency Television Advertising	$ 3,315	1/
Normalization Period	3	
Normalized Amount	$ 1,105	
Test year Amount	3,315	
Adjustment to Energy Conservation/Efficiency Television Advertising	$ (2,210)	
Institutional Advertising Included in Account 909	$ 400	1/
Remove Institutional Advertising Included in Account 909	$ (400)	
Adjustment to T&D O&M Expenses	$ (2,610)	
PAPUC Jurisdictional Allocation Factor	100.00%	2/
Adjustment to O&M Expenses	$ (2,610)	

Notes:

1/ Response to OTS-RE-62-D.

2/ Calculated based on data presented on Exhibit JMK-2, Page 25, Line 4.

Docket No. R-00072155
Schedule LKM-13

PPL ELECTRIC UTILITIES CORPORATION

Adjustment to Normalize Materials and Supplies Expense
For the Test Year Ended December 31, 2007
($000)

	Amount	
Non-Capital Repairs to Substation Equipment	$ 800	1/
Adjustment to T&D O&M Expenses	$ (800)	
PAPUC Jurisdictional Allocation Factor	99.92%	2/
Adjustment to O&M Expenses	$ (799)	

Notes:
1/ Response to OCA VI-11.
2/ Calculated based on data presented on Exhibit JMK-2, Page 25, Line 2.

Docket No. R-00072155
Schedule LKM-14

PPL ELECTRIC UTILITIES CORPORATION

Adjustment to Annualize Pension Expense
For the Test Year Ended December 31, 2007
($000)

	Amount	
PPL Retirement Plan		
Pension Cost per PPL Corp. March 2007 Actuarial Study	$ 25,966	1/
Black Lung Funds	4,000	2/
Net Pension Costs	$ 21,966	
PPL Electric Allocation Factor	35.75%	3/
PPL Electric Allocated Pension Costs	$ 7,853	
O&M Percentage	64.50%	3/
PPL Electric Pension Expense	$ 5,065	
PPL Electric Pension Expense per Budget	6,457	3/
Adjustment to PPL Retirement Plan Expenses	$ (1,392)	
PPL Supplemental Executive Retirement Plan (SERP)		
PPL Corp. 2006 SERP Actuarial Cost	$ 8,100	4/
PPL Electric Allocation Factor	7.50%	3/
PPL Electric Allocated Pension Costs	$ 608	1/
O&M Percentage	64.50%	3/
PPL Electric SERP Pension Expense	$ 392	
PPL Electric SERP Pension Expense per Budget	367	3/
Adjustment to T&D O&M Expenses	$ 25	
Adjustment to T&D O&M Expenses	$ (1,367)	
PAPUC Jurisdictional Allocation Factor	89.54%	5/
Total Adjustment to O&M Expense	$ (1,224)	

Notes:

1/ Page MS-1 of March 2007 Actuarial Valuation Report provided in the response to OTS-RE-69.
2/ Per Response to OCA VI-20.
3/ Per Response to OCA I-38.
4/ Actuarial Valuation Report provided in Attachment 3 to the response to OTS-RE-69.
5/ Calculated based on data presented on Exhibit JMK-2, Page 23, Line 6.

Docket No. R-00072155
Schedule LKM-15

PPL ELECTRIC UTILITIES CORPORATION

Adjustment to Annualize Postretirement Benefits Other Than Pension Expense
For the Test Year Ended December 31, 2007
($000)

		Amount	
2006 OPEB Actuarial Study Costs	$	34,328	1/
PPL Electric Allocation Factor		37.41%	2/
PPL Electric Allocated OPEB Costs	$	12,842	
O&M Percentage		64.50%	2/
PPL Electric OPEB Expense	$	8,283	
PPL Electric OPEB Expense per 2007 Budget		8,688	2/
Adjustment to T&D O&M Expenses	$	(405)	
PAPUC Jurisdictional Allocation Factor		89.54%	3/
Adjustment to O&M Expense	$	(362)	

Notes:

1/ Page MS-1 of Actuarial Valuation Report provided in Attachment 5 of the response to OTS-RE-69.

2/ Per Response to OCA I-39.

3/ Calculated based on data presented on Exhibit JMK-2, Page 23, Line 6.

Docket No. R-00072155
Schedule LKM-16

PPL ELECTRIC UTILITIES CORPORATION

Adjustment to Annualize Property Insurance Expense
For the Test Year Ended December 31, 2007
($000)

	Amount	
Unsupported Costs Included in Account 926	$ 413	1/
Adjustment to T&D O&M Expenses	$ (413)	
PAPUC Jurisdictional Allocation Factor	89.54%	2/
Adjustment to O&M Expenses	$ (370)	

Notes:
1/ Response to OTS-RE-67.
2/ Calculated based on data presented on Exhibit JMK-2, Page 20, Line 4.

Docket No. R-00072155
Schedule LKM-17

PPL ELECTRIC UTILITIES CORPORATION

Adjustment to Remove Storm Damage Insurance Expense
For the Test Year Ended December 31, 2007
($000)

	Amount	
Annual Storm Insurance Expense	$ 7,560	1/
Adjustment to T&D O&M Expenses	$ (7,560)	
PAPUC Jurisdictional Allocation Factor	76.04%	2/
Adjustment to O&M Expenses	$ (5,749)	

Notes:

1/ Exhibit Historic I, Schedule D-10.

2/ Calculated based on data presented on Exhibit JMK-1, Page 20, Line 11.

Docket No. R-00072155
Schedule LKM-18

PPL ELECTRIC UTILITIES CORPORATION

Adjustment to Normalize Negative Net Salvage

For the Test Year Ended December 31, 2007
($000)

	Cost of Removal		Gross Salvage		Negative Net Salvage	
12 Months Ending:						
December 31, 2002	$ 7,936	1/	$ (1,392)	1/	$ 6,544	
December 31, 2003	11,860	2/	(1,802)	2/	10,058	
December 31, 2004	13,097	2/	(1,453)	2/	11,644	
December 31, 2005	11,076	2/	(5,906)	2/	5,170	
December 31, 2006	13,710	2/	(2,564)	2/	11,146	
5-Year Average per OCA					$ 8,912	
5-Year Average per Company					9,504	2/
Adjustment					$ (592)	
PAPUC Jurisdictional Allocation Factor					89.54%	
Adjustment to Depreciation & Amortization Expenses					$ (530)	

Notes:
1/ Response to OCA I-50.
2/ Attachment II-D-13.

Docket No. R-00072155
Schedule LKM-19

PPL ELECTRIC UTILITIES CORPORATION

Adjustment to Normalize Capital Stock Tax Expense
For the Test Year Ended December 31, 2007
($000)

	Amount 1/
2003 Net Income	$ 28,470
2004 Net Income	60,302
2005 Net Income	92,437
2006 Net Income	85,102
2007 Net Income	126,534
Total Book Income	$ 392,845
Average Net Income	$ 78,569
Average Net Income / 9.5%	$ 827,042
Net Worth @ End of Year	$ 1,236,625
Net Worth per Return X .75	$ 927,469
Total Average Net Income / 9.5% and Net Worth per Return X .75	$ 1,754,511
Subtotal Divided by 2	$ 877,255
Less Exemption	(150)
Capital Stock Value	$ 877,105
Apportionment Percentage	0.895720
Taxable Value	$ 785,641
Rate	0.289% 2/
Capital Stock Tax	$ 2,271
PA Education Tax Credit	(144)
Net Capital Stock Tax	$ 2,127
Capital Stock Tax per Company	2,912
Adjustment to Taxes Other Than Income	$ (641)

Notes

1/ Exhibit Future D-12, Page 2.

2/ Capital Stock Tax Rate Effective 2008.

Docket No. R-00072155
Schedule LKM-20

PPL ELECTRIC UTILITIES CORPORATION

Interest Synchronization Adjustment
For the Test Year Ended December 31, 2007

		Amount	
OCA Rate Base	$	2,014,632	1/
Weighted Cost of Debt		2.75%	
Adjusted Interest Deduction	$	55,402	
Interest Deduction Per Company		55,667	2/
Adjustment to Synchronize Interest Expense	$	(265)	
Effective State Income Tax Rate		9.99%	
Adjustment to State Income Taxes	$	26	
Federal Income Tax Base		($239)	
Federal Income Tax Rate		35.00%	
Adjustment to Federal Income Taxes	$	84	

Notes:

1/ Schedule LKM-2, Page 1.

2/ Exhibit JMK-2, Section III, Page 28.

OCA STATEMENT NO. 1S
Hbg TX AUG 1 3 2007

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

PPL ELECTRIC UTILITIES)
CORPORATION) DOCKET NO. R-00072155

SURREBUTTAL TESTIMONY OF

LAFAYETTE K. MORGAN, JR.

RECEIVED
AUG 1 4 2007
PA PUBLIC UTILITY COMMISSION
SECRETARY'S BUREAU

ON BEHALF OF THE

OFFICE OF CONSUMER ADVOCATE

AUGUST 2007

DOCUMENT
FOLDER

EXETER
ASSOCIATES, INC.
5565 Sterrett Place
Suite 310
Columbia, Maryland 21044

TABLE OF CONTENTS

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

PPL ELECTRIC UTILITIES)
CORPORATION) DOCKET NO. R-00072155

Surrebuttal Testimony of Lafayette K. Morgan, Jr.

Introduction and Summary

Q. WOULD YOU PLEASE STATE YOUR NAME AND BUSINESS ADDRESS?

A. My name is Lafayette K. Morgan, Jr. I am a Senior Regulatory Analyst with Exeter Associates, Inc. Our offices are located at 5565 Sterrett Place, Columbia, Maryland 21044. Exeter is a firm of consulting economists specializing in issues pertaining to public utilities.

Q. ARE YOU THE SAME LAFAYETTE MORGAN JR. WHO PRESENTED DIRECT TESTIMONY IN THIS PROCEEDING?

A. Yes, I am.

Q. WHAT IS THE PURPOSE FOR YOUR SURREBUTTAL TESTIMONY?

A. The purpose of my surrebuttal testimony is to respond to the rebuttal testimonies of PPL witnesses Schadt, Krall and Kleha.

Q. ARE YOU PRESENTING ANY SCHEDULES WITH YOUR SURREBUTTAL TESTIMONY?

A. Yes. I have attached Schedules LKM-1S through LKM-20S to this testimony. These schedules present the OCA's updated position on PPL's rate increase. Based upon the revisions I have made, and discuss herein, the OCA is now recommending an increase in distribution revenues of $38.0 million.

Q. ARE THERE ANY ISSUES ON WHICH YOU BELIEVE THE COMPANY AND THE OCA AGREE WITH REGARD TO REVENUE REQUIREMENTS?

A. Yes. I believe the Company and the OCA are in agreement on the following issues:

- Plant Held for Future Use
- Lead/Lag Days
- Miscellaneous Revenues
- Relocation Costs Forfeited Discounts
- Telephone and Leased Wire Expense
- Pension Expense Postretirement Benefits Expense
- Negative Net Salvage
- Capital Stock Tax

Cash Working Capital

Q. YOU INDICATE ABOVE THAT THE OCA AND PPL ARE IN AGREEMENT ON LEAD/LAG DAYS. WHY DO YOU STILL MAKE AN ADJUSTMENT TO CASH WORKING CAPITAL?

A. In my direct testimony, I recommended several adjustments to the lead/lag days that affected Materials and Supplies Expense, Printing and Office Supplies Expense, Tree Trimming Expense and Work By Outsiders Expense. In Mr. Kleha's rebuttal testimony, he addressed my concerns about each of those expenses, and made changes to the Company's lag days. I believe the changes made by the Company to the lead/lag days are reasonable. Therefore, I have accepted the lag days used in the Company's revised lead/lag study. However, an adjustment to cash working capital is still necessary because of corollary affects of those O&M expenses about which we still disagree. This is a routine adjustment that does not represent any philosophical difference on working capital components. On Schedule LKM-6S, page 1, I present this adjustment which reduces Pennsylvania jurisdictional rate base by $1,102,000.

Rent from Electric Property

Q. MR. SCHADT HAS DISAGREED WITH YOUR ADJUSTMENT TO RENT FROM ELECTRIC PROPERTY REVENUES, BUT HAS REVISED THE RENT FROM ELECTRIC PLANT THAT PPL HAS INCLUDED IN THE COST OF SERVICE. WOULD YOU PLEASE COMMENT ON HIS REBUTTAL TESTIMONY ON THIS ISSUE?

A. In my direct testimony, I recommended an adjustment to Rent from Electric Property to reflect growth in those revenues consistent with previous periods. Mr. Schadt disagrees with my adjustment primarily because of the growth rate I used in my adjustment. In short, Mr. Schadt believes the 8.14 percent that I used in deriving my adjustment is too high. He also goes on to characterize my adjustment as arbitrary, and states that there is no basis to conclude that PPL's growth between 2006 and 2007 will be as high as its 2005 to 2006 growth.

In my direct testimony, I explained how I chose the growth rate that I used in my adjustment and that a data limitation existed when I prepared my testimony. Despite the data limitation, I used a growth rate from data that was directly related to rent from electric property, which was not at all arbitrary as Mr. Schadt has stated. In fact, I point out in my direct testimony that an attempt was made not to overstate the growth rate by limiting the period from which the growth rate was calculated. That being said, PPL, in its rebuttal testimony, has now provided better data for the 2004 to 2006 period, which I believe is more appropriate to use for ratemaking purposes.

Q. DO YOU AGREE WITH THE GROWTH THAT THE COMPANY REFLECTED IN ITS REVISED RENT FROM ELECTRIC PROPERTY REVENUES?

A. No. Rather than use the historic growth rate to project the ongoing revenues for the rate effective period, Mr. Schadt has chosen to use the revenues budgeted for the 2007 budget year. According to him, these revenues are based on known contracts and rates and reflect recent experience. On Exhibit JRS 5, Schedule 2, Document 1, he shows that the compound growth rate for the 2004 to 2006 period is 1.93 percent. I believe it is more appropriate to use the historic compound growth rate rather than the 2007 projected revenue. Applying the historic growth rate to the historic test year revenue produces an ongoing level of revenues that is likely to be received during the rate effective period. Conversely, the 2007 revenues that the Company has proposed do not reflect the ongoing level of revenues during the rate effective period. Instead, they only reflect the level of revenues expected to be received during 2007. The rates from this proceeding will be in effect during 2008 and beyond. Based on the historic growth pattern, the revenues collected during the rate effective period would more likely reflect the growth of the 2006 revenues at the historic growth rate rather than 2007 budget revenues.

Based on the foregoing, I have revised my adjustment to Rent from Electric Property to the 1.93 percent growth rate rather than the 8.14 percent used in my direct testimony. This adjustment is presented on Schedule LKM-9S and it reflects an increase in rent from electric property revenues of $357,000.

Employee Expenses

Q. PLEASE EXPLAIN THE REMAINING DIFFERENCE BETWEEN THE OCA AND PPL RELATING TO EMPLOYEE EXPENSES.

A. In my direct testimony, I proposed an adjustment to remove a portion of employee relocation costs and other employee expenses. The relocation cost was adjusted because it appeared to be unusually high when compared to the previous year. When I inquired about the unusual level of the relocation expenses, PPL explained that what appeared to be higher than usual costs were caused by the hiring of new high level managers. In my direct testimony, I explained that such expenses were not recurring costs, and that it would be proper to remove them from the cost of service. In its rebuttal testimony, the Company stated that the data I was provided contained an error, and that the historical test year expense was higher than what was reported. In view of the corrected data, the future test year amount proposed by the Company is reasonable and does not warrant an adjustment. Therefore, I have withdrawn my adjustment to remove a portion of relocation costs.

With regard to Other Employee Expenses, I removed a portion of the costs as not being supported, and the Company has not offered any new data to show that the costs it included are reasonable. According to the response to OTS-RE-129, during the historic test year PPL incurred costs of $500,000 relating to employee travel and attendance to meeting and seminars. Based on its budget, PPL included $600,000 in the future test year for these same activities. This amount reflects a 20 percent increase over the historic test year amount. I do not have a problem with this portion of the future test year costs as it is not unusual to recognize some growth in expenses. The problem is created when, further on in the data response, PPL indicates that it included $300,000 for what appear to be the same activities for which it had already included $600,000. Although PPL describes the additional $300,000 slightly differently by labeling it as the costs related to offsite seminars and conferences, PPL (in the response to OCA VI-14) confirms that the 2006 expenses of $500,000 did include the costs of attending offsite seminars and conferences. In the response to OCA VI-14, the Company failed to provide any additional support for such a significant increase. In Mr. Schadt's rebuttal testimony, he simply asserts that my adjustment is wrong but again offers no additional data to support his claim. Therefore, it is still my position that the costs have not been supported, and I am recommending that the Commission adopt the $300,000 adjustment to remove those expenses. On Schedule LKM-10S, I present this adjustment which decreases O&M expense by $269,000 on a Pennsylvania jurisdictional basis.

Materials and Supply Expense

Q. WOULD YOU PLEASE ADDRESS THE CRITICISM OF YOUR ADJUSTMENT TO NORMALIZE MATERIALS AND SUPPLIES EXPENSE BY MR. SCHADT?

A. Yes. In my direct testimony I recommended an adjustment to normalize Materials and Supplies expense by removing nonrecurring costs. Mr. Schadt has responded by focusing on one data response, which could lead the Commission to make the wrong conclusion about this issue. Hence, it is necessary to clarify the issue before responding to Mr. Schadt's claim. The goal of my analysis was to determine the components of the increase in materials and supplies and to ensure that the components were appropriately supported.

In its cost of service, PPL has included $6,714,000, which reflects an increase of $1,324,000 in O&M expenses for Materials and Supplies Expense. PPL stated that the increase was caused by the return of unused materials and supplies to inventory during 2006.[1] As part of my review, it was necessary to determine whether the 2006 return of materials and supplies was an unusual event, and if not, whether the

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[1] When materials and supplies are issued for use in operations, the costs are charged to expenses causing an increase in expenses. When unused materials and supplies are returned to inventory, the costs are credited to materials and supplies causing a decrease in expenses.

budgeted expenses reflected the normal return of unused materials and supplies to inventory. In the response to OCA VI-10, PPL stated that the return of materials and supplies to inventory was a normal part of operations. The Company also confirmed that due to the manner in which the budgets are prepared, the budgeted amount for materials and supplies expense did not include more costs than needed.

From the response to OCA I-11, I was also able to determine that only a portion of the $1,324,000 was actually related to the return of unused materials. According to that response, the total amount of the materials and supplies returned to inventory during 2006 was $566,558. As a result, out of the $1,324,000 increase in expenses that the PPL had claimed as being related to return of materials and supplies to inventory, $757,000 was unaccounted for. In the response to OCA VI-11, PPL explained this difference by essentially indicating that it had increased the O&M budget by $800,000 to account for repairs and replacement of non-capital substation repairs and replacement.

However, the Company's actual budgets do not support the $800,000 increase reflected in the cost of service. In the response to OCA I-12, PPL stated that the budget for materials and supplies for repairs and replacement for 2007, 2008 and 2009 was $5,129,000, $5,411,000 and $5,842,000, respectively. In comparison, the actual expense for 2004, 2005 and 2006 were $5,096,000, $4,461,000 and $5,390,000. As can be seen, the 2007 budget is less than the actual 2006 amount, the 2008 budget is slightly higher than the 2006 amount, and the 2009 budget is $450,000 higher than the 2006 amount ($350,000 less than the $800,000 amount included in the cost of service). Hence, there appears to be no corroborating documentation to support the $800,000 increase that the Company is claiming.

Q. WHY DO YOU BELIEVE MR. SCHADT'S REBUTTAL TESTIMONY COULD LEAD TO AN ERRONEOUS CONCLUSION?

A. Mr. Schadt simply shows the growth in the materials and supplies budget with no reference to the actual expense and then points to a higher total expense budget to prove that expenses are increasing. He presents budget data as if they are actual expenses, when in reality there are many variables that can change those amounts. In fact, by the time the 2009 budget is finalized and adopted, the amounts are likely to be very different from the amount he uses to support his 8.8 percent cost increase. Consistent with that finding, I believe the Commission should reject Mr. Schadt's position and adopt my adjustment to reduce O&M expenses by $800,000 as shown on Schedule LKM-13S.

Storm Damage Insurance Expense

Q. WOULD YOU PLEASE RESPOND TO MR. KRALL'S REBUTTAL TESTIMONY ON STORM DAMAGE INSURANCE EXPENSE?

A. Yes. Mr. Krall's rebuttal testimony attempts to discredit my testimony by citing what he sees as "fundamental errors" in my analysis. First, he criticizes me for summing up the total insurance costs and the amount collected in rates for storm damage. However, he states that amount should have been lower because I should have only considered the distribution portion of the insurance costs. Second, he states that I underestimated the cost of the ice storm damage by considering only the O&M costs. He further confuses this issue by citing "another way to analyze" the benefit of the storm damage insurance. Nevertheless, Mr. Krall has offered an alternative to the Company's initial claim whereby the PPL will accept recovery of the actual 5-year average storm damage costs. This would result in a decrease of $3.5 million on a

Pennsylvania jurisdictional basis from the Company's initial claim. The alternative proposal by PPL is acceptable to the OCA because it reflects a normalized level of actual storm damage cost which tend to fluctuate from year to year. Therefore, on Schedule LKM-17S, I have revised my adjustment to reflect this reduction in costs.

Consumer Education Advertising Expenses

Q. MR. KRALL DISAGREES WITH YOUR ADJUSTMENT TO NORMALIZE A PORTION OF THE CONSUMER EDUCATION ADVERTISING EXPENSES. PLEASE RESPOND TO HIS TESTIMONY.

A. My primary disagreement with Mr. Krall on the consumer education advertising expense centers on the $3.3 million of television advertising. Based on all the evidence provided, there is not an adequate basis to conclude that the Company will be spending that amount of money on television advertising on an ongoing basis.

Mr. Krall responded to my direct testimony by stating in his rebuttal testimony that I have misinterpreted the data response, which he attached to his testimony. As can be seen in the data response, it is stated that the Company "<u>anticipates</u>" spending $4.4 million per year. In my view "anticipates" does not imply a commitment or that there are definite plans to make these expenditure. In the response to OCA VII-20, the Company provided the MDMS Business Case, which presumably is the document that supports the investment in the MDMS. As I pointed out in my direct testimony, the business case, which includes the expenditures for future years, does not include the $4.4 million. Mr. Krall acknowledges this on page 18, lines 19 to 21 of his rebuttal testimony. Despite no evidence or any planning document to show that level of expenditure will be made, Mr. Krall's conclusion that I have misinterpreted the data in reaching the decision to remove the costs from O&M

expenses is unfounded. The Commission, therefore, should reject his position and adopt my adjustment reducing expenses by $2.2 million as presented on Schedule LKM-12S.

Q. HOW DO YOU RESPOND TO MR. KRALL'S REBUTTAL ON THE INSTITUTIONAL ADVERTISING EXPENSE ADJUSTMENT THAT YOU REMOVED FROM THE COST OF SERVICE?

A. I believe the Commission has been clear on its position on institutional advertising. In fact, Mr. Krall does not dispute the Commission's stance on institutional advertising as stated in my direct testimony. Instead, his rebuttal indicates that the costs that were described as institutional advertising are really informational advertising. However, he offers no documentation or advertising copy to support the Company's claim. Therefore, I believe my adjustment to remove the $400,000 on Schedule LKM-12S should be accepted by the Commission.

Negative Net Salvage

Q. MR. SCHADT INDICATES IN HIS REBUTTAL TESTIMONY THAT THE COMPANY CORRECTED AN ERROR IN ITS NET SALVAGE CLAIM. HOW DOES THIS AFFECT YOUR ADJUSTMENT?

A. When I calculated my adjustment to negative net salvage amortization, I used the $9,504,000 amount reported on Question II-D-13 of the Company's filing as the amount included in the cost of service. In Mr. Schadt's rebuttal, he states that the actual amount included in the cost of service as filed was $12,005,000 rather than the $9,504,000. As a result, the Company has corrected the error in its rebuttal filing.

Despite the fact that the cost of service includes the correct amount for negative net salvage, my $530,000 adjustment is unchanged. This is because my adjustment assumed that the corrected amount of $9,504,000 was the amount included in the cost of service. PPL's $9,504,000 is based upon four years of historical data and one year of projected data. As I indicated in my direct testimony, counsel has advised me that the Commission has previously allowed amortization of net salvage based upon five years of actual historical data. The use of actual 5-year historical negative net salvage is reasonable because the Company is allowed to recover its actual net salvage costs. Given that the net salvage is not subject to true-up, the use of the projected data may result in an over- or under-recovery of net salvage. Therefore, the Company's negative net salvage amortization should be adjusted by $530,000 as shown on Schedule LKM-18S.

Q. DOES THIS CONCLUDE YOUR SURREBUTTAL TESTIMONY?

A. Yes, it does.

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BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

PPL ELECTRIC UTILITIES CORPORATION	))	DOCKET NO. R-00072155

SCHEDULES ACCOMPANYING THE SURREBUTTAL TESTIMONY OF

LAFAYETTE K. MORGAN, JR.

ON BEHALF OF THE

OFFICE OF CONSUMER ADVOCATE

AUGUST 2007

EXETER
ASSOCIATES, INC.
5565 Sterrett Place
Suite 310
Columbia, Maryland 21044

PPL ELECTRIC UTILITIES CORPORATION

Summary of Operating Income
For the Test Year Ended December 31, 2007
($000)

	PAPUC Jurisdictional Amount per Co.	OCA Cost of Service Adjustments	Amount After Adjustments	OCA Recommended Change In Revenue	After Proposed Rate Increase
Operating Revenues	$ 667,322	$ 357	$ 667,679	$ 37,893	$ 705,572
Late Payment Revenue	9,262	-	9,262	113	9,375
Total Operating Revenues	$ 676,584	$ 357	$ 676,941	$ 38,006	$ 714,947
<u>Operating Expenses</u>					
O&M Expenses	$ 339,648	$ (7,194)	$ 332,454	$ 304	$ 332,758
Depreciation & Amortization Expenses	109,643	(530)	109,113	-	109,113
Taxes Other Than Income	49,227	-	49,227	2,241	51,468
Current State Income Tax	9,824	804	10,628	3,543	14,171
Current Federal Income Tax	33,162	2,534	35,696	11,171	46,867
Deferred Income Taxes	8,378	-	8,378	-	8,378
Investment Tax Credit	(1,673)	-	(1,673)	-	(1,673)
Total Operating Expenses	$ 548,209	$ (4,386)	$ 543,823	$ 17,259	$ 561,082
Net Operating Income	$ 128,375	$ 4,743	$ 133,118	$ 20,747	$ 153,865
Rate Base	$ 2,020,328		$ 2,019,226		$ 2,019,226
Return On Rate Base	6.35%		6.59%		7.62%

PPL ELECTRIC UTILITIES CORPORATION

Summary of Revenue Increase at OCA Rate of Return
For the Test Year Ended December 31, 2007
($000)

		Amount	
Adjusted Rate Base		$ 2,019,226	Schedule LKM-2S, Page 2
Required Rate of Return		7.62%	
Net Operating Income Required		$ 153,865	
Net Operating Income at Present Rates		133,118	Schedule LKM-1S, Page 1
Income Deficiency/(Surplus)		$ 20,747	
Revenue Multiplier		1.83186	
Required Change in Company Revenue		$ 38,006	
Proposed Revenue Change		$ 38,006	
Uncollectibles	0.80%	304	
Gross Revenues Tax	5.90%	2,241	
Subtotal		$ 35,461	
State Income Tax	9.99%	3,543	
Subtotal		$ 31,918	
Federal Income Tax	35.00%	11,171	
Net Income Increase Required		$ 20,747	

Docket No. R-00072155
Schedule LKM- 2S
Page 1 of 2

PPL ELECTRIC UTILITIES CORPORATION

Summary of Rate Base
For the Test Year Ended December 31, 2007
($000)

	PAPUC Jurisdictional Amount per Co.	OCA Rate Base Adjustments	Amount After Adjustments
Total Plant in Service	$ 3,848,933	$ -	$ 3,848,933
Accumulated Depreciation	(1,464,244)	-	(1,464,244)
Net Plant in Service	$ 2,384,689	$ -	$ 2,384,689
Cash Working Capital	$ 18,063	$ (1,102)	$ 16,961
Materials & Supplies	24,250	-	24,250
Plant Held For Future Use	-	-	-
Customer Advances	(269)	-	(269)
Customer Deposits	(15,950)	-	(15,950)
Accumulated Deferred Income Taxes	(390,455)	-	(390,455)
Total Rate Base	$ 2,020,328	$ (1,102)	$ 2,019,226

PPL ELECTRIC UTILITIES CORPORATION

Summary of Rate Base Adjustments
For the Test Year Ended December 31, 2007
($000)

	Source	PAPUC Jurisdictional Amount per Co.
Rate Base per Company Filing	*Schedule LKM-2S, Page 1*	*$ 2,020,328*
OCA Adjustments:		
Plant Held For Future Use	Schedule LKM-5S	$ -
Cash Working Capital	Schedule LKM-6S, Page 1	(1,102)
Total Ratemaking Adjustments		$ (1,102)
Adjusted Rate Base per OCA		$ 2,019,226

PPL ELECTRIC UTILITIES CORPORATION

Summary of Adjustments to Net Income
For the Test Year Ended December 31, 2007
($000)

	Total Company Amount
Net Income per Company	$ 128,375
OCA Adjustments:	
Reflect Miscellaneous Revenues	$ -
Annualize Forfeited Discount Revenues	-
Annualize Rent from Electric Property Revenues	209
Remove Excess Employee Expenses	157
Normalize Telephone and Leased Wire Expense	-
Normalize Advertising Expense	1,527
Normalize Materials and Supplies Expense	467
Annualize Pension Expense	-
Annualize OPEB Expense	-
Annualize Property Insurance Expense	-
Remove Storm Insurance Expense	2,056
Normalize Negative Net Salvage	310
Normalize Capital Stock Tax	-
Interest Synchronization	16
Total Ratemaking Adjustments	$ 4,743
Total Adjusted Net Income per OCA	$ 133,118

PPL ELECTRIC UTILITIES CORPORATION

Summary of Adjustments to Net Income
For the Test Year Ended December 31, 2007
($000)

	Operating Revenues	O&M Expenses	Depreciation & Amortization Expenses	Taxes Other Than Income	Current State Income Taxes	Current Federal Income Tax	Deferred Income Taxes	Investment Tax Credit	Net Operating Income
PA Jurisdictional Amount per Company	$ 676,584	$ 339,648	$ 109,643	$ 49,227	$ 9,824	$ 33,162	$ 8,378	$ (1,673)	$ 128,375
OCA Adjustments:									
Reflect Miscellaneous Revenues	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Annualize Forfeited Discount Revenues	-	-	-	-	-	-	-	-	-
Annualize Rent from Electric Property Revenues	357	-	-	-	36	112	-	-	209
Remove Excess Employee Expenses	-	(269)	-	-	27	85	-	-	157
Normalize Telephone and Leased Wire Expense	-	-	-	-	-	-	-	-	-
Normalize Advertising Expense	-	(2,610)	-	-	261	822	-	-	1,527
Normalize Materials and Supplies Expense	-	(799)	-	-	80	252	-	-	467
Annualize Pension Expense	-	-	-	-	-	-	-	-	-
Annualize OPEB Expense	-	-	-	-	-	-	-	-	-
Annualize Property Insurance Expense	-	-	-	-	-	-	-	-	-
Remove Storm Insurance Expense	-	(3,515)	-	-	351	1,108	-	-	2,056
Normalize Negative Net Salvage	-	-	(530)	-	53	167	-	-	310
Normalize Capital Stock Tax	-	-	-	-	-	-	-	-	-
Interest Synchronization	-	-	-	-	(4)	(12)	-	-	16
Total Ratemaking Adjustments	$ 357	$ (7,194)	$ (530)	$ -	$ 804	$ 2,534	$ -	$ -	$ 4,743
Total Adjusted Income	$ 676,941	$ 332,454	$ 109,113	$ 49,227	$ 10,628	$ 35,696	$ 8,378	$ (1,673)	$ 133,118

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Schedule LKM-4S

PPL ELECTRIC UTILITIES CORPORATION

Reconciliation of Current State and Federal Income Taxes
For the Test Year Ended December 31, 2007

		Test Year Per Company	Ratemaking Adjustments	Test Year at Present Rates	Rate Change at OCA Rate of Return	After Proposed Increase
CALCULATION OF COMBINED CURRENT INCOME TAX						
Net Operating Income Before Income Taxes		$ 171,361	$ 8,081	$ 179,442	$ 35,461	$ 214,903
Adjustments for Income Taxes (Including Interest)		(64,702)	(37)	(64,739)	-	(64,739)
Subtotal		$ 106,659	$ 8,044	$ 114,703	$ 35,461	$ 150,164
Special Tax Deductions		(8,320)	-	(8,320)	-	(8,320)
State Taxable Income		$ 98,339	$ 8,044	$ 106,383	$ 35,461	$ 141,844
State Income Tax	9.99%	$ 9,824	$ 804	$ 10,628	$ 3,543	$ 14,170
Federal Taxable Income Before State Income Tax		$ 106,659	$ 8,044	$ 114,703	$ 35,461	$ 150,164
State Income Tax		$ 9,824	$ 804	$ 10,628	$ 3,543	$ 14,170
Federal Taxable Income		$ 96,835	$ 7,240	$ 104,075	$ 31,918	$ 135,994
Federal Income Tax	35.00%	33,892	2,534	36,426	11,171	47,598
Consolidated Tax Adjustment		(616)	-	(616)	-	(616)
Federal Tax Credits		(114)	-	(114)	-	(114)
Net Federal Income Tax		$ 33,162	$ 2,534	$ 35,696	$ 11,171	$ 46,868
Net Combined Current Income Tax		$ 42,986	$ 3,338	$ 46,324	$ 14,714	$ 61,038
Total Combined Current Income Taxes (Schedule LKM-1, Page 1)		42,986	3,338	46,324	14,714	61,038
Unreconciled/Rounding		$ -	$ -	$ -	$ -	$ -

Docket No. R-00072155
Schedule LKM-5S

PPL ELECTRIC UTILITIES CORPORATION

Adjustment to Remove Plant Held For Future Use
For the Test Year Ended December 31, 2007
($000)

	PAPUC Jurisdictional Amount 1/
Total Distribution Plant Held For Future Use Included in Rate Base	$ -
Adjustment to Rate Base	$ -

Notes:
1/ Exhibit Future 1, C-1.

PPL ELECTRIC UTILITIES CORPORATION

Adjustment to Allowance for Cash Working Capital
For the Test Year Ended December 31, 2007
($000)

		Amount	
O&M Expense Cash Working Capital	$	15,106	1/
Average Prepayments		2,470	2/
Accrued Taxes		16,906	3/
Interest Payments		(9,139)	4/
Preferred and Preference Dividends		9	5/
Total Cash Working capital requirement per OCA	$	25,352	
Total Cash Working capital requirement per Company		26,931	2/
Adjustment to Cash Working Capital	$	(1,579)	
PAPUC Jurisdictional Allocation Factor		69.79%	6/
Adjustment to Cash Working Capital	$	(1,102)	

Notes:
1/ Schedule LKM 6S, Page 2.
2/ Exhibit Future 1-Revised, C-4, Page 1.
3/ Schedule LKM 6S, Page 5.
4/ Schedule LKM 6S, Page 6.
5/ Schedule LKM 6S, Page 7.
6/ Calculated based on data presented on Exhibit JMK-2A-Revised, Page 17, Line 10.

PPL ELECTRIC UTILITIES CORPORATION

O&M Allowance for Cash Working Capital
For the Test Year Ended December 31, 2007
($000)

	Amount 1/
Total Pro Forma O&M Expenses	$ 579,384
Less: Non-cash Items and Adjustments	
Uncollectibles	20,155
On-Track Customer Assistance Expense	4,500
Amortization of 2005 Ice Storm Cost	1,611
Remove Excess Employee Expenses	300
Normalize Telephone and Leased Wire Expense	-
Normalize Advertising	2,610
Normalize Materials and Supplies Expense	800
Adjustment to Pension Expense	-
Adjustment to Postretirement Benefits Expense	-
Annualize Property Insurance Expense	-
Remove Storm Insurance Expense	3,515
Total Reductions from Working Capital Base	33,491
Pro Forma O&M Expenses for Cash Working Capital	$ 545,893
Daily O&M Expense	$ 1,496
Average Revenue Lag Days	45.20 2/
Average O&M Expense Lag Days	35.10 1/
Average Net Lag	10.10
O&M Expense Cash Working Capital per OCA	$ 15,106

Notes:

1/ Exhibit Future 1-Revised, C-4, Page 2.

2/ Revenue Lag Days per Exhibit Historic C-4, Page 2.

PPL ELECTRIC UTILITIES CORPORATION

Calculation of O&M Expenses Lag
For the Test Year Ended December 31, 2007

Amount 1/	Lag Days 1/	Dollar Days

Withdrawn

Notes:
1/ Exhibit Historic C-4, Page 2.
2/ Schedule LKM-6S, Page 4.

PPL ELECTRIC UTILITIES CORPORATION

Calculation of Other Expenses Lag
For the Test Year Ended December 31, 2007

Amount 1/	Lag Days 1/	Dollar Days

Withdrawn

Notes:
1/ Attachment II-B-4, Page 4.
2/ Schedule LKM-6S, Page 8.
3/ Schedule LKM-6S, Page 9.
4/ Schedule LKM-6S, Page 10.
5/ Schedule LKM-6S, Page 11.

PPL ELECTRIC UTILITIES CORPORATION

Accrued Taxes
For the Test Year Ended December 31, 2007

	Amount	12-Month Accrued Factor 1/	Accrued Taxes
Federal Income Tax	$ 65,679	-3.82%	$ (2,509)
PA Income Taxes	20,847	-1.74%	(363)
PA Gross Receipts Tax	52,777	35.76%	18,873
PA Capital Stock Tax	2,012	-1.74%	(35)
PA Public Utility Realty Tax	4,039	23.26%	939
Total Accrued Taxes			$ 16,906

Notes:
1/ Exhibit Future C-4, Page 4.

PPL ELECTRIC UTILITIES CORPORATION

Interest Payments
For the Test Year Ended December 31, 2007

		Amount	
Total Company Rate Base	$	2,644,059	
Weighted Cost of Debt		2.82%	
Pro forma Interest Expense	$	74,562	
Daily Interest Expense	$	204	
Net Interest Lag Days		44.80	1/
Total Accrued Taxes	$	9,139	

Notes:
1/ Exhibit Future C-4, Page 5.

Docket No. R-00072155
Schedule LKM-6S

PPL ELECTRIC UTILITIES CORPORATION

Preferred and Preference Dividends
For the Test Year Ended December 31, 2007

	Accrued Taxes	
Total Company Rate Base	$ 2,644,059	
Weighted Cost of Debt	0.65%	
Pro forma Interest Expense	$ 17,186	
Daily Interest Expense	$ 47	
Net Interest Lag Days	(0.20)	1/
Total Accrued Taxes	$ (9)	

Notes:
1/ Exhibit Future C-4, Page 6.

PPL ELECTRIC UTILITIES CORPORATION

Calculation of Materials Expense Lag
For the Test Year Ended December 31, 2007

Voucher Number 1/	Invoice Number 1/	Mid Point of Service Period 1/	Payment Date 1/	Amount 1/	Lag Days 1/	Dollar Days

Withdrawn

Notes:
1/ Attachment II-B-4, Page 4.
2/ Response to OTS-RE-111-D.

PPL ELECTRIC UTILITIES CORPORATION

Calculation of Printing & Office Supply Expense Lag
For the Test Year Ended December 31, 2007

Voucher Number 1/	Invoice Number 1/	Mid Point of Service Period 1/	Payment Date 1/	Amount 1/	Lag Days 1/	Dollar Days

Withdrawn

Notes:
1/ Attachment II-B-4, Page 5.
2/ Response to OTS-RE-112-D.

PPL ELECTRIC UTILITIES CORPORATION

Calculation of Tree Trimming Expense Lag
For the Test Year Ended December 31, 2007

Voucher Number 1/	Invoice Number 1/	Mid Point of Service Period 1/	Payment Date 1/	Amount 1/	Lag Days 1/	Dollar Days

Withdrawn

Notes:
1/ Attachment II-B-4, Page 6.
2/ Response to OTS-RE-113-D.

PPL ELECTRIC UTILITIES CORPORATION

Calculation of Work By Outsiders Lag
For the Test Year Ended December 31, 2007

Voucher Number 1/	Invoice Number 1/	Mid Point of Service Period 1/	Payment Date 1/	Amount 1/	Lag Days 1/	Dollar Days

Withdrawn

Notes:
1/ Attachment II-B-4, Page 7.
2/ Response to OTS-RE-114-D.

Docket No. R-00072155
Schedule LKM-7S

PPL ELECTRIC UTILITIES CORPORATION

Adjustment to Reflect Miscellaneous Revenues
For the Test Year Ended December 31, 2007
($000)

	Jurisdictional Amount	
Total Historic Test Year Miscellaneous Revenues	$ 369	1/
Total Miscellaneous Revenues per Company	369	2/
Adjustment to Miscellaneous Revenues	$ -	

Notes:
1/ Exhibit Historic 1, D-3, Page 1.
2/ Exhibit Future 1-Revised, D-3, Page 1.

Docket No. R-00072155
Schedule LKM-8S

PPL ELECTRIC UTILITIES CORPORATION

Adjustment to Annualize Forfeited Discount Revenues
For the Test Year Ended December 31, 2007
($000)

	Amount 1/
Total Sale of Electricity Revenues	$ 3,122,688
3-Year Forfeited Discount Ratio	0.30%
Annualized Forfeited Discount Revenues	$ 9,262
Annualized Forfeited Discount Revenues Per Company	9,262
Adjustment to Forfeited Discount Revenues	$ -

Notes:
1/ Exhibit JRS 5, Schedule 1, Document 1.

Docket No. R-00072155
Schedule LKM-9S

PPL ELECTRIC UTILITIES CORPORATION

Adjustment to Annualize Rent from Electric Property Revenues
For the Test Year Ended December 31, 2007
($000)

	Amount 1/
2006 Jurisdictional Rent from Electric Property Revenues	$ 29,481
2004 -2006 Compund Annual Growth Rate	1.93%
Annualized Jurisdictional Rent from Electric Property Revenues	$ 30,050
Annualized Jurisdictional Rent from Electric Property Revenues per PPL	29,693
Adjustment to Revenues	$ 357

Notes:
1/ Exhibit JRS 5, Schedule 2, Document 1.

Docket No. R-00072155
Schedule LKM-10S

PPL ELECTRIC UTILITIES CORPORATION

Adjustment to Remove Excess Employee Expenses
For the Test Year Ended December 31, 2007
($000)

	Amount	
Unusual Relocation Location Costs	$ -	1/
Unsupported Employee Expenses	300	1/
Adjustment to T&D O&M Expenses	$ (300)	
PAPUC Jurisdictional Allocation Factor	89.83%	2/
Adjustment to O&M Expenses	$ (269)	

Notes:
1/ Response to OTS-RE-129.
2/ Calculated based on data presented on Exhibit JMK-2, Page 20, Line 5.

Docket No. R-00072155
Schedule LKM-11S

PPL ELECTRIC UTILITIES CORPORATION

Adjustment to Normalize Telephone and Leased Wire Expense
For the Test Year Ended December 31, 2007
($000)

	Amount	
Telephone and Leased Wire Expense	$ 400	1/
Normalization Period (Years)	3	
Normalized Telephone and Leased Wire Expense	$ 133	
Telephone and Leased Wire Expense Included in Cost of Service	133	2/
Adjustment to T&D O&M Expenses	$ 0	
PAPUC Jurisdictional Allocation Factor	100.00%	
Adjustment to O&M Expenses	$ -	

Notes:

1/ Response to OTS-RE-129.

2/ Witness Schadt's Rebuttal Testimony at Pages 8 and 9.

Docket No. R-00072155
Schedule LKM-12S

PPL ELECTRIC UTILITIES CORPORATION

Adjustment to Normalize Advertising Expense
For the Test Year Ended December 31, 2007
($000)

	Amount	
Energy Conservation/Efficiency Television Advertising	$ 3,315	1/
Normalization Period	3	
Normalized Amount	$ 1,105	
Test year Amount	3,315	
Adjustment to Energy Conservation/Efficiency Television Advertising	$ (2,210)	
Institutional Advertising Included in Account 909	$ 400	1/
Remove Institutional Advertising Included in Account 909	$ (400)	
Adjustment to T&D O&M Expenses	$ (2,610)	
PAPUC Jurisdictional Allocation Factor	100.00%	2/
Adjustment to O&M Expenses	$ (2,610)	

Notes:

1/ Response to OTS-RE-62-D.

2/ Calculated based on data presented on Exhibit JMK-2, Page 25, Line 4.

PPL ELECTRIC UTILITIES CORPORATION

Adjustment to Normalize Materials and Supplies Expense
For the Test Year Ended December 31, 2007
($000)

	Amount	
Non-Capital Repairs to Substation Equipment	$ 800	1/
Adjustment to T&D O&M Expenses	$ (800)	
PAPUC Jurisdictional Allocation Factor	99.92%	2/
Adjustment to O&M Expenses	$ (799)	

Notes:
1/ Response to OCA VI-11.
2/ Calculated based on data presented on Exhibit JMK-2, Page 25, Line 2.

Docket No. R-00072155
Schedule LKM-14S

PPL ELECTRIC UTILITIES CORPORATION

Adjustment to Annualize Pension Expense
For the Test Year Ended December 31, 2007
($000)

	Amount 1/
PPL Retirement Plan	
Pension Cost per PPL Corp. March 2007 Actuarial Study	$ 25,966
Black Lung Funds	-
Net Pension Costs	$ 25,966
PPL Electric Allocation Factor	35.75%
PPL Electric Allocated Pension Costs	$ 9,283
O&M Percentage	64.50%
PPL Electric Pension Expense	$ 5,987
PPL Electric Pension Expense per Budget	5,987
Adjustment to PPL Retirement Plan Expenses	$ -
PPL Supplemental Executive Retirement Plan (SERP)	
PPL Corp. 2006 SERP Actuarial Cost	$ 7,187
PPL Electric Allocation Factor	7.59%
PPL Electric Allocated Pension Costs	$ 545
O&M Percentage	64.50%
PPL Electric SERP Pension Expense	$ 352
PPL Electric SERP Pension Expense per Budget	352
Adjustment to T&D O&M Expenses	$ -
Adjustment to T&D O&M Expenses	$ -
PAPUC Jurisdictional Allocation Factor	89.54%
Total Adjustment to O&M Expense	$ -

Notes:

1/ Exhibit JRS 5, Schedule 7, Document 1.

Docket No. R-00072155
Schedule LKM-15S

PPL ELECTRIC UTILITIES CORPORATION

Adjustment to Annualize Postretirement Benefits Other Than Pension Expense
For the Test Year Ended December 31, 2007
($000)

	Amount 1/
2006 OPEB Actuarial Study Costs	$ 39,505
PPL Electric Allocation Factor	37.41%
PPL Electric Allocated OPEB Costs	$ 14,779
O&M Percentage	64.50%
PPL Electric OPEB Expense	$ 9,532
PPL Electric OPEB Expense per 2007 Budget	9,532
Adjustment to T&D O&M Expenses	$ -
PAPUC Jurisdictional Allocation Factor	89.54%
Adjustment to O&M Expense	$ -

Notes:
1/ Exhibit JRS 5, Schedule 8, Document 1.

Docket No. R-00072155
Schedule LKM-16S

PPL ELECTRIC UTILITIES CORPORATION

Adjustment to Annualize Property Insurance Expense
For the Test Year Ended December 31, 2007
($000)

	Amount	
Unsupported Costs Included in Account 926	$ -	1/
Adjustment to T&D O&M Expenses	$ -	
PAPUC Jurisdictional Allocation Factor	89.54%	2/
Adjustment to O&M Expenses	$ -	

Notes:
1/ Response to OTS-RE-67.
2/ Calculated based on data presented on Exhibit JMK-2, Page 20, Line 4.

Docket No. R-00072155
Schedule LKM-17S

PPL ELECTRIC UTILITIES CORPORATION

Adjustment to Remove Storm Damage Insurance Expense
For the Test Year Ended December 31, 2007
($000)

		Amount	
Five-year Average Storm Damage Expense	$	12,800	
PAPUC Jurisdictional Allocation Factor		76.04%	1/
Jurisdictional Five-year Average Storm Damage Expense	$	9,734	
Total Jurisdictional Storm Damge Insurance Premiums and Normalized Storm Damge not Covered by Insurance		13,249	2/
Adjustment to T&D O&M Expenses	$	(3,515)	
PAPUC Jurisdictional Allocation Factor		100.00%	2/
Adjustment to O&M Expenses	$	(3,515)	

Notes:
1/ Calculated based on data presented on Exhibit JMK-1, Page 20, Line 11.
2/ Mr. Krall's Rebuttal Testimony at Page 7, line 22.

Docket No. R-00072155
Schedule LKM-18S

PPL ELECTRIC UTILITIES CORPORATION

Adjustment to Normalize Negative Net Salvage

For the Test Year Ended December 31, 2007
($000)

	Cost of Removal		Gross Salvage		Negative Net Salvage	
12 Months Ending:						
December 31, 2002	$ 7,936	1/	$ (1,392)	1/	$ 6,544	
December 31, 2003	11,860	2/	(1,802)	2/	10,058	
December 31, 2004	13,097	2/	(1,453)	2/	11,644	
December 31, 2005	11,076	2/	(5,906)	2/	5,170	
December 31, 2006	13,710	2/	(2,564)	2/	11,146	
5-Year Average per OCA					$ 8,912	
5-Year Average per Company					9,504	2/
Adjustment					$ (592)	
PAPUC Jurisdictional Allocation Factor					89.54%	
Adjustment to Depreciation & Amortization Expenses					$ (530)	

Notes:
1/ Response to OCA I-50.
2/ Attachment II-D-13.

Docket No. R-00072155
Schedule LKM-19S

PPL ELECTRIC UTILITIES CORPORATION

Adjustment to Normalize Capital Stock Tax Expense
For the Test Year Ended December 31, 2007
($000)

	Amount 1/
2003 Net Income	$ 28,470
2004 Net Income	60,302
2005 Net Income	92,437
2006 Net Income	85,102
2007 Net Income	50,350
Total Book Income	$ 316,661
Average Net Income	$ 63,332
Average Net Income / 9.5%	$ 666,655
Net Worth @ End of Year	$ 1,332,576
Net Worth per Return X .75	$ 999,432
Total Average Net Income / 9.5% and Net Worth per Return X .75	$ 1,666,087
Subtotal Divided by 2	$ 833,043
Less Exemption	(150)
Capital Stock Value	$ 832,893
Apportionment Percentage	0.895720
Taxable Value	$ 746,039
Rate	0.289% 2/
Capital Stock Tax	$ 2,156
PA Education Tax Credit	(144)
Net Capital Stock Tax	$ 2,012
Capital Stock Tax per Company	2,012
Adjustment to Taxes Other Than Income	$ -

Notes
1/ Exhibit Future 1 D-12, Page 2, Revised 7/27/2007.
2/ Capital Stock Tax Rate Effective 2008.

Docket No. R-00072155
Schedule LKM-20S

PPL ELECTRIC UTILITIES CORPORATION

Interest Synchronization Adjustment
For the Test Year Ended December 31, 2007

		Amount	
OCA Rate Base	$	2,019,226	1/
Weighted Cost of Debt		2.82%	
Adjusted Interest Deduction	$	56,942	
Interest Deduction Per Company		56,905	2/
Adjustment to Synchronize Interest Expense	$	37	
Effective State Income Tax Rate		9.99%	
Adjustment to State Income Taxes	$	(4)	
Federal Income Tax Base		$33	
Federal Income Tax Rate		35.00%	
Adjustment to Federal Income Taxes	$	(12)	

Notes:
1/ Schedule LKM-2, Page 1.
2/ Exhibit JMK-2A-Revised, Section III, Page 28.

OCA St. No. 2

AUG 13 2007

BEFORE THE PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA PUBLIC UTILITY COMMISSION

V.

PPL ELECTRIC UTILITIES CORPORATION

DOCKET NO. R-00072155

DOCUMENT
FOLDER

DIRECT TESTIMONY OF

DAVID C. PARCELL

RECEIVED

AUG 14 2007

PA PUBLIC UTILITY COMMISSION
SECRETARY'S BUREAU

TOPIC ADDRESSED:
FAIR RATE OF RETURN

ON BEHALF OF
OFFICE OF CONSUMER ADVOCATE

JULY 6, 2007

TABLE OF CONTENTS

APPLICATION OF
PPL ELECTRIC UTILITIES CORPORATION
DOCKET NO. R-00072155

DIRECT TESTIMONY
OF
DAVID C. PARCELL

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME, OCCUPATION, AND BUSINESS ADDRESS.

A. My name is David C. Parcell. I am President and Senior Economist of Technical Associates, Inc. My business address is Suite 601, 1051 East Cary Street, Richmond, Virginia 23219.

Q. PLEASE BRIEFLY DESCRIBE YOUR BACKGROUND AND EXPERIENCE.

A. I hold B.A. (1969) and M.A. (1970) degrees in economics from Virginia Polytechnic Institute and State University (Virginia Tech) and a M.B.A. (1985) from Virginia Commonwealth University. I have been a consulting economist with Technical Associates since 1970. In connection with this, I have previously filed cost of capital testimony in about 400 public utility ratemaking proceedings before some 40 regulatory agencies in the United States and Canada.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. I have been retained by the Office of Consumer Advocate ("OCA") to evaluate the cost of capital aspects of the current filing of PPL Electric Utilities Corporation ("PPL Electric" or "Company"). I have performed independent studies and am making recommendations of the current cost of capital for PPL Electric. In addition, since PPL Electric is a subsidiary of PPL Corporation ("PPL" or "Parent"), I have also evaluated this entity in my analyses.

Q. HAVE YOU PREPARED AN EXHIBIT IN SUPPORT OF YOUR TESTIMONY?

A. Yes, I have prepared one exhibit, labeled Exhibit DCP-1, identified as Schedule 1 through Schedule 15. This exhibit was prepared either by me or under my direction. The information contained in this exhibit is correct to the best of my knowledge and belief.

II. RECOMMENDATIONS AND SUMMARY

Q. WHAT ARE YOUR RECOMMENDATIONS IN THIS PROCEEDING?

A. My overall cost of capital recommendation for PPL Electric is:

	Percent	Cost	Return
Long-Term Debt	46.41%	5.93%	2.75%
Preferred Stock	10.46%	6.24%	0.65%
Common Equity	43.13%	9.63%	4.15%
Total	100.00%		7.56%[1]

The application of PPL Electric requests a return on common equity of 11.5 percent and overall rate of return of 8.36 percent.

Q. PLEASE SUMMARIZE YOUR ANALYSES AND CONCLUSIONS.

A. This proceeding is concerned with PPL Electric's regulated electric utility operations in Pennsylvania. My analyses are concerned with the Company's total cost of capital. The first step in performing these analyses is the development of the appropriate capital structure. PPL Electric's proposed capital structure is the estimated December 31, 2007 capital structure of the Company. I have also used this capital structure in my analyses.

The second step in a cost of capital calculation is a determination of the embedded cost rates of debt and preferred stock. I have used the cost rates for debt and preferred stock proposed by PPL Electric.

The third step in the cost of capital calculation is the estimation of the cost of common equity. I have employed three recognized methodologies to estimate the cost of equity for PPL Electric. Each of these methodologies is applied to two groups of proxy electric utilities. These three methodologies and my findings are:

Methodology	Range
Discounted Cash Flow	9.0-10.25% (9.63% mid-point)
Capital Asset Pricing Model	9.9-10.3% (10.1% mid-point)
Comparable Earnings	10.0%

---

[1] The 7.56% total reflects the actual total cost of capital, as shown on Schedule 13. This contrasts with the apparent 7.55% sum of the individual "return" figures shown above. The difference relates to the fact that the actual returns listed here are rounded, whereas Schedule 13 indicates non-rounded figures.

Based upon these findings, it is my conclusion that the cost of common equity for PPL Electric is within a range of 9 percent to 10.25 percent (9.625 percent mid-point), which reflects the range for each model examined. I recommend 9.625 percent as the cost of equity for PPL Electric. I note that this recommendation gives more weight to the DCF methodology.

Combining these three steps into weighted cost of capital results in an overall rate of return of 7.56 percent (which incorporates a cost of common equity of 9.625 percent).

III. ECONOMIC/LEGAL PRINCIPLES AND METHODOLOGIES

Q. WHAT ARE THE PRIMARY ECONOMIC AND LEGAL PRINCIPLES THAT ESTABLISH THE STANDARDS FOR DETERMINING A FAIR RATE OF RETURN FOR A REGULATED UTILITY?

A. Public utility rates are normally established in a manner designed to allow the opportunity for recovery of their costs, including capital costs. This is frequently referred to as "cost of service" ratemaking. Rates for regulated public utilities traditionally have been primarily established using the "rate base - rate of return" concept. Under this method, utilities are allowed to recover a level of operating expenses, taxes, and depreciation deemed reasonable for rate-setting purposes, and are granted an opportunity to earn a fair rate of return on the assets utilized (i.e., rate base) in providing service to their customers.

The rate base is derived from the asset side of the utility's balance sheet as a dollar amount, and the rate of return is developed from the liabilities/owners' equity side of the balance sheet as a percentage. The revenue impact of the cost of capital is thus derived by multiplying the rate base by the rate of return and allowing a factor for income taxes.

The rate of return is developed from the cost of capital, which is estimated by weighting the capital structure components (i.e., debt, preferred stock, and common equity) by their percentages in the capital structure and multiplying these by their cost rates. This is also known as the weighted cost of capital.

Technically, "fair rate of return" is a legal and accounting concept that refers to an ex post (after the fact) earned return on an asset base, while the cost of capital is an economic and financial concept which refers to an ex ante (before the fact) expected or required return on a liability base. In regulatory proceedings, however, the two terms are often used interchangeably. I have equated the two concepts in my testimony.

From an economic standpoint, a fair rate of return is normally interpreted to mean that an efficient and economically managed utility will be able to maintain its financial integrity, attract capital, and establish comparable returns for similar risk investments.

These concepts are derived from economic and financial theory and are generally implemented using financial models and economic concepts.

Although I am not a lawyer, and I do not offer a legal opinion, my testimony is based on my understanding that two United States Supreme Court decisions are universally cited as providing the standards for a fair rate of return. The first is Bluefield Water Works and Improvement Company v. Public Serv. Comm'n of West Virginia, 262 U.S. 679 (1923). In this decision, the Court stated:

> What annual rate will constitute **just compensation** depends upon many circumstances and must be **determined by** the **exercise of fair and enlightened judgment**, having regard to all relevant facts. A **public utility** is entitled to such rates as will permit it to **earn a return** on the value of the property which it employs for the convenience of the public equal to that **generally being made** at the same time and in the same general part of the country on **investments in other business undertakings** which are **attended by corresponding risks and uncertainties**; but it has no **constitutional right to profits** such as are realized or anticipated in **highly profitable enterprises or speculative ventures**. The **return** should be reasonably sufficient to assure confidence in the **financial soundness** of the utility, and should be adequate, **under efficient and economical management**, to maintain and **support its credit** and **enable it to raise the money** necessary for the proper discharge of its public duties. A rate of return may be reasonable at one time, and become too high or too low by changes affecting opportunities for investment, the money market, and business conditions generally.

Bluefield, 262 U.S. at 692-93 (emphasis added). It is my understanding that the Bluefield decision established the following standards for a fair rate of return: comparable earnings, financial integrity, and capital attraction. It also noted the changing level of required returns over time as well as an underlying assumption that the utility be operated in an efficient manner.

The second decision is Federal Power Commission v. Hope Natural Gas Company, 320 U.S. 591 (1942). In that decision, the Court stated:

> The rate-making process under the [Natural Gas] Act, i.e., the fixing of 'just and reasonable' rates, involves a **balancing** of the **investor** and **consumer interests** . . . . From the investor or company point of view it is important that there be enough revenue not only for operating expenses but also for the capital costs of the business. These include service on the debt and dividends on the stock. By that standard the **return** to the equity

> **owner** should be **commensurate** with **returns** on **investments** in **other enterprises having corresponding risks**. That return, moreover, should be sufficient to assure confidence in the **financial integrity** of the enterprise, so as to ***maintain its credit*** and to ***attract capital***.

Hope, 320 U.S. at 603 (emphasis added). The Hope case is also frequently credited with establishing the "end result" doctrine, which maintains that it is the end result that is reviewed for reasonableness.

The three economic and financial parameters in the Bluefield and Hope decisions— comparable earnings, financial integrity, and capital attraction— reflect the economic criteria encompassed in the "opportunity cost" principle of economics. The opportunity cost principle provides that a utility and its investors should be afforded an opportunity (not a guarantee) to earn a return commensurate with returns they could expect to achieve on investments of similar risk. The opportunity cost principle is consistent with the fundamental premise on which regulation rests, namely, that it is intended to act as a surrogate for competition.

Q. HOW CAN THESE PARAMETERS BE EMPLOYED TO ESTIMATE THE COST OF CAPITAL FOR A UTILITY?

A. Neither the courts nor economic/financial theory have developed exact and mechanical procedures for precisely determining the cost of capital. This is the case because the cost of capital is an opportunity cost and is prospective-looking, which dictates that it must be estimated.

There are several useful models that can be employed to assist in estimating the cost of equity capital - the component of the capital structure that is the most difficult to determine. These include the discounted cash flow ("DCF"), capital asset pricing model ("CAPM"), comparable earnings ("CE") and risk premium ("RP") methods. Each of these methods (or models) differs from the others and each, if properly employed, can be a useful tool in estimating the cost of common equity for a regulated utility.

Q. WHICH METHODS HAVE YOU EMPLOYED IN YOUR ANALYSES OF THE COST OF COMMON EQUITY IN THIS PROCEEDING?

A. I have utilized three methodologies to determine PPL Electric's cost of common equity: the DCF, CAPM, and CE methods. Each of these methodologies will be described in more detail in my testimony that follows.

IV. GENERAL ECONOMIC CONDITIONS

Q. WHY ARE ECONOMIC AND FINANCIAL CONDITIONS IMPORTANT IN DETERMINING THE COSTS OF CAPITAL?

A. The costs of capital, for both fixed-cost (debt and preferred stock) components and common equity, are determined in part by current and prospective economic and financial conditions. At any given time, each of the following factors has an influence on the costs of capital: the level of economic activity (i.e., growth rate of the economy), the stage of the business cycle (i.e., recession, expansion, or transition), and the level of inflation. My understanding is that use of the factors is consistent with the Supreme Court's Bluefield decision, which noted that "[a] rate of return may be reasonable at one time, and become too high or too low by changes affecting opportunities for investment, the money market, and business conditions generally." 262 U.S. at 693.

Q. WHAT INDICATORS OF ECONOMIC AND FINANCIAL ACTIVITY HAVE YOU EVALUATED IN YOUR ANALYSES?

A. I have examined several sets of economic statistics for the period 1975 to present. I chose this period because it permits the evaluation of economic conditions over three full business cycles plus the current cycle to date, and thus makes it possible to assess changes in long-term trends. This period also approximates the beginning and continuation of active rate case activities by public utilities.

A business cycle is commonly defined as a complete period of expansion (recovery and growth) and contraction (recession). A full business cycle is a useful and convenient period over which to measure levels and trends in long-term capital costs because it incorporates the cyclical (i.e., stage of business cycle) influences and thus permits a comparison of structural (or long-term) trends.

Q. PLEASE DESCRIBE THE TIMEFRAME OF THE THREE PRIOR BUSINESS CYCLES AND THE MOST CURRENT CYCLE.

A. The three prior complete cycles and current cycle cover the following periods:

Business Cycle	Expansion Cycle	Contraction Period
1975-1982	Mar. 1975-July 1981	Aug. 1981-Oct. 1982
1982-1991	Nov. 1982-July 1990	Aug. 1990-Mar. 1991
1991-2001	Apr. 1991-Mar. 2001	Apr. 2001-Nov. 2001
Current	Dec. 2001-Present	

Q. DO YOU HAVE ANY GENERAL OBSERVATIONS CONCERNING THE CHANGING TRENDS IN ECONOMIC CONDITIONS AND THEIR IMPACT ON COSTS OVER THIS BROAD PERIOD?

A. Yes, I do. As I will describe below, the U.S. economy has enjoyed general prosperity and stability over the period since the early 1980s. This period has been characterized by longer economic expansions, relatively tame contractions, relatively low and declining inflation, and declining interest rates and other capital costs. The current business cycle began in late 2001, following a somewhat modest recession in 2001. During the recession and early in the succeeding expansion, the Federal Reserve lowered interest rates (i.e., the Federal Funds rate) eleven times in 2001 and twice in 2003 in an effort to stimulate the economy.

Q. PLEASE DESCRIBE RECENT AND CURRENT ECONOMIC AND FINANCIAL CONDITIONS AND THEIR IMPACT ON THE COSTS OF CAPITAL.

A. Schedule 2 shows several sets of economic data. Page 1 contains general macroeconomic statistics while Pages 2 and 3 contain financial market statistics. Page 1 of Schedule 2 shows that the U.S. economy is currently in the fifth year of an economic expansion. This is indicated by the growth in real (i.e., adjusted for inflation) Gross Domestic Product, industrial production, and the unemployment rate. This current expansion has generally been characterized as slower growth, in comparison to prior expansions. This has resulted in lower inflationary pressures and interest rates.

The rate of inflation is also shown on Page 1 of Schedule 2. As is reflected in the Consumer Price Index (CPI), for example, inflation rose significantly during the 1975-1982 business cycle and reached double-digit levels in 1979-1980. The rate of inflation declined substantially in 1981 and remained at or below 6.1 percent during the 1983-1991 business cycle. The 2.5 percent rate of inflation in 2006 was similar to the levels since 2000, but was well below the levels of the past thirty years.

Q. WHAT HAVE BEEN THE TRENDS IN INTEREST RATES?

A. Pages 2 and 3 of Schedule 2 shows several series of interest rates. Rates rose sharply to record levels in 1975-1981 when the inflation rate was high and generally rising. Interest rates then fell substantially in conjunction with inflation rates throughout the remainder of the 1980s and throughout the 1990s. Interest rates declined even further from 2000-2004 and generally recorded their lowest levels since the 1960s.

This low level of interest rates, in conjunction with the recent strength of the U.S. economy, may create an expectation that any near-term movement of interest rates will be upward. In fact, the Federal Reserve has, since the middle of 2004, increased short-term interest rates on seventeen occasions, although each time by only 0.25 percent, in an attempt to insure that any perceived inflationary expectations will not stifle continued economic growth. Nevertheless, the economic recovery to date has not resulted in a pronounced increase in long-term rates. Further, the current level of the Federal Funds rate is about the same as the level in existence when the series of reductions began in 2000. Even if long-term rates were to increase moderately, they would still remain well below historical levels.

Q. WHAT HAVE BEEN THE TRENDS IN COMMON SHARE PRICES?

A. Page 4 of Schedule 2 shows several series of common stock prices and ratios. These indicate that share prices were basically stagnant during the high inflation/interest rate environment of the late 1970s and early 1980s. On the other hand, the 1983-1991 business cycle and the most recent cycle have witnessed a significant upward trend in stock prices. During the initial years of the current expansion, however, stock prices were volatile and declined substantially from their highs reached in 1999 and early 2000. Share prices have increased somewhat since 2003 and currently stand at near record high levels.

Q. WHAT CONCLUSIONS DO YOU DRAW FROM THIS DISCUSSION OF ECONOMIC AND FINANCIAL CONDITIONS?

A. It is apparent that capital costs are currently low in comparison to the levels that have prevailed over the past three decades. In addition, even a moderate increase in interest rates, as well as other capital costs, would still result in capital costs that are low by historic standards. Therefore, it can reasonably be expected that cost of equity models currently produce returns that are lower than was the case in prior years.

V. PPL ELECTRIC'S CAPITAL STRUCTURE AND COSTS OF DEBT & PREFERRED STOCK

Q. PLEASE BRIEFLY DESCRIBE PPL ELECTRIC.

A. PPL Electric is an electric utility that serves approximately 1.4 million customers in 29 counties of Pennsylvania. The Company was historically known as Pennsylvania Power & Light Company, prior to the creation of its holding company structure during restructuring. PPL Electric is a subsidiary of PPL.

Q. PLEASE DESCRIBE PPL.

A. PPL is an energy and utility holding company. PPL has the following three reportable segments.

- Supply - domestic energy marketing and domestic generation and domestic development operations of PPL Energy Supply.
- International Delivery - international energy businesses of PPL Global that are primarily focused on the distribution of electricity; and,
- Pennsylvania Delivery - regulated electric and gas delivery operations of PPL Electric and PPL Gas Utilities.

Q. WHAT HAVE BEEN THE BUSINESS SEGMENT RATIOS OF PPL IN RECENT YEARS?

A. This is shown on Schedule 3. Schedule 3 indicates, as of 2006, the Pennsylvania Delivery segment (which is dominated by PPL Electric) accounted for about one-half of the revenues of PPL, about one-fifth of net income, and about one-fourth of total assets. Of the Pennsylvania Delivery segment's operations, PPL Electric is much larger than PPL Gas. It is thus clear that PPL Electric is the primary component of PPL.

Q. WHAT ARE THE CURRENT BOND RATINGS OF PPL AND PPL ELECTRIC?

A. The current ratings of PPL and PPL Electric are:

	Standard & Poor's	Moody's	Fitch
PPL Credit Ratings			
Issuer Rating	BBB	Baa2	BBB
PPL Electric Credit Ratings			
First Mortgage Bonds	A-	A3	A-

Source: UniSource Energy Web Site

It is apparent that PPL Electric's single-A rated debt is higher than PPL, which has triple-B rated debt. This differential is due, in large part, to the lower risk which PPL Electric faces, as well as the "ring fencing" of the Company's debt that somewhat insulates it from the non-regulated activities of PPL.

Q. HOW HAVE YOU EVALUATED THE CAPITAL STRUCTURE OF PPL ELECTRIC?

A. I examined the recent (2002-2006) capital structure ratios of PPL Electric. These are shown on Schedule 4, Page 1. I have summarized below the common equity ratios for PPL Electric:

	Including S-T Debt	Excluding S-T Debt
2002	42.1%	42.3%
2003	44.1%	44.1%
2004	46.6%	47.3%
2005	45.0%	45.7%
2006	42.0%	42.6%

This indicates that PPL Electric's equity ratio increased from 2002 to 2004, then decreased slightly since 2004.

Q. WHAT HAVE BEEN THE RECENT CAPITAL STRUCTURES OF PPL?

A. These are shown on Schedule 4, Page 2. The common equity ratios of PPL have been as follows:

2006	42.0%	42.2%
	Including S-T Debt	Excluding S-T Debt
2002	32.7%	36.9%
2003	33.5%	33.6%
2004	40.9%	41.0%
2005	41.5%	42.4%

These common equity ratios are seen to be slightly lower than those of PPL Electric.

Q. HOW DO PPL ELECTRIC'S COMMON EQUITY RATIOS COMPARE WITH THOSE OF OTHER ELECTRIC UTILITIES?

A. Schedule 5 shows this comparison. This indicates that PPL Electric's current common equity ratio is slightly lower than those of the two groups of electric companies followed by AUS Utility Reports.

Q. WHAT CAPITAL STRUCTURE RATIOS HAS PPL ELECTRIC REQUESTED IN THIS PROCEEDING?

A. The Company requests use of a capital structure, estimated as of December 31, 2007, comprised of 43.13 percent common equity, 10.46 percent preferred stock, and 46.41 percent debt. I also use this capital structure in my cost of capital analyses.

Q. WHAT ARE THE COST RATES OF DEBT AND PREFERRED STOCK IN THE COMPANY'S APPLICATION?

A. The Company's filing cites a cost rate of long-term debt of 5.93 percent and a cost of preferred stock of 6.24 percent. I use the company-proposed rates for debt and preferred stock in my cost of capital analyses. In accepting these rates, I note that the Company represents that the calculations are consistent with the manner in which debt and preferred stock costs were calculated in the Company's last rate proceeding.

Q. CAN THE COST OF COMMON EQUITY BE DETERMINED WITH THE SAME DEGREE OF PRECISION AS THE COST OF DEBT?

A. No. The cost rate of debt is largely determined by interest payments, issue prices, and related expenses. The cost of common equity, on the other hand, cannot be precisely quantified, primarily because this cost is an opportunity cost. There are, however, several models which can be employed to estimate the cost of common equity. Three of the primary methods – DCF, CAPM, and CE – are developed in the following sections of my testimony. I note that this Commission and other regulatory Commissions favor the DCF methodology, and I accordingly give more weight to this methodology in my recommendation.

VI. SELECTION OF COMPARISON GROUPS

Q. HOW HAVE YOU ESTIMATED THE COST OF COMMON EQUITY FOR PPL ELECTRIC?

A. PPL Electric is not a publicly-traded company. Consequently, it is not possible to directly apply cost of equity models to PPL Electric. PPL is publicly-traded, but its diversified operations indicate that this Company should not be used as the sole source of PPL Electric's cost of equity.

It is customary to analyze groups of comparison or "proxy" companies to determine the cost of common equity for public utilities. I have examined two such groups for comparison to PPL Electric. The first group of proxy companies is a group of eleven electric and combination gas electric companies that have similar operating and risk characteristics to those of PPL and PPL Electric. These companies are identified on Schedule 6.

The second proxy group is the group of eight electric utilities that PPL Electric witness Moul used in his analyses, a list of which is found on Schedule 7.

VII. DISCOUNTED CASH FLOW ANALYSIS

Q. WHAT IS THE THEORY AND METHODOLOGICAL BASIS OF THE DISCOUNTED CASH FLOW MODEL?

A. The discounted cash flow (DCF) model is one of the oldest, as well as the most commonly-used, models for estimating the cost of common equity for public utilities. It is my understanding that this Commission places primary reliance on the DCF method in setting rates for public utilities. The DCF model is based on the "dividend discount model" of financial theory, which maintains that the value (price) of any security or commodity is the discounted present value of all future cash flows. The most common variant of the DCF model assumes that dividends are expected to grow at a constant rate. This variant of the dividend discount model is known as the constant growth or Gordon DCF model. This is the most commonly-used DCF model. The constant growth aspect of the model reflects an assumption that the growth rate is assumed to be constant (as opposed to a multi-stage growth assumption). I have used the Gordon DCF model because it is the most commonly-used version of DCF and also because I believe it more directly reflects investor decision making. In this framework, the price of a stock is determined as follows:

$$K = \frac{D}{P} + g$$

where:
P = current price
D = current dividend rate
K = discount rate (cost of capital)
G = constant rate of expected growth

This formula essentially states that the return expected or required by investors is comprised of two factors: the dividend yield (current income) and expected growth in dividends (future income).

Q. PLEASE EXPLAIN HOW YOU HAVE EMPLOYED THE DCF MODEL.

A. I have utilized the constant growth DCF model. In doing so, I have combined the current dividend yield for each group of comparison utility stocks described in the previous section with several indicators of expected dividend growth.

Q. HOW DID YOU DERIVE THE DIVIDEND YIELD COMPONENT OF THE DCF EQUATION?

A. There are several methods which can be used for calculating the dividend yield component. These methods generally differ in the manner in which the dividend rate is employed, i.e., current versus future dividends or annual versus quarterly compounding of dividends. I believe the most appropriate dividend yield component is a quarterly compounding variant which is expressed as follows:

$$Yield = \frac{D_0(1+0.5g)}{P_0}$$

This dividend yield component recognizes the timing of dividend payments and dividend increases.

The P_0 in my yield calculation is the average (of high and low) stock prices for each company for the most recent three month period (March-May, 2007). The D_0 is the current annualized dividend rate for each company.

Q. HOW HAVE YOU ESTIMATED THE DIVIDEND GROWTH COMPONENT OF THE DCF EQUATION?

A. The dividend growth rate component of the DCF model is usually the most crucial and controversial element involved in using this methodology. The objective of estimating the dividend growth component is to reflect the growth expected by investors which is embodied in the price (and yield) of a company's stock. As such, it is important to recognize that individual investors have different expectations and consider alternative indicators in deriving their expectations. A wide array of techniques exist for estimating the growth expectations of investors. As a result, it is evident that no single indicator of growth is always used by all investors. It therefore is necessary to consider alternative indicators of dividend growth in deriving the growth component of the DCF model.

I have considered five indicators of growth in my DCF analyses. These are:

1. 2002-2006 (5 year average) earnings retention, or fundamental growth;
2. 5 year average of historic growth in earnings per share (EPS), dividends per share (DPS), and book value per share (BVPS);
3. 2007-2011 projections of earnings retention growth;
4. 2004-2011 projections of EPS, DPS, and BVPS; and
5. 5 year projections of EPS growth as reported in First Call.

I believe this combination of growth indicators is a representative and appropriate set with which to estimate investor expectations of dividend growth for the groups of comparison companies.

Q. PLEASE DESCRIBE YOUR DCF CALCULATIONS.

A. Schedule 7 presents my DCF analysis. Page 1 shows the calculation of the "raw" (i.e., prior to adjustment for growth) dividend yield. Pages 2-3 show the growth rate for the groups of comparison companies. Page 4 shows the DCF calculations, which are presented on several bases: mean, median and high values. These results can be summarized as follows:

	Mean	Median	High Value
Comparison Group	9.2%	9.1%	10.2%
Moul Group	7.8%	8.0%	11.3%

I note that these calculations should not be interpreted as my DCF conclusions, but rather as numeric values that form the basis of quantitative and qualitative analyses of the cost of capital at the current time.

Q. WHAT DO YOU CONCLUDE FROM YOUR DCF ANALYSES?

A. Based upon my analyses, I believe a range of 9 percent to 10.25 percent represents the current DCF cost of equity for the comparison groups. This is approximated by the upper portion of the range of DCF calculations for the electric groups examined in the previous analysis. The 9 percent rate reflects the upper portion of the mean/median results, while the 10.25 percent rate approximates the "high value" DCF results for the Comparison Group. I have not given weight in my DCF recommendation to the 11.2 percent "high value" for the Moul Group since this is largely determined by the single growth rate (i.e., EPS) for a single company (i.e., Northeast Utilities – 12.0 percent) that is clearly an "outlier". Mr. Moul's Testimony on page 4, lines 8-14 also appears to support this view.

Q. MR. MOUL STATES, IN HIS TESTIMONY, THAT THE PENNSYLVANIA COMMISSION HAS, IN RECENT CASES, ADDED SOME 45 BASIS POINTS TO THE DCF RESULTS TO REFLECT MARKET-TO-BOOK RATIOS OF OVER 100 PERCENT. SHOULD SUCH AN ADJUSTMENT BE ADDED TO YOUR DCF RECOMMENDATION?

A. No, it should not. My DCF conclusions, which focus on the high end of the DCF results, already reflect relatively high levels of market-to-book ratios. As I indicate above, both the low-end of my DCF range (9.0 percent) and the upper-end (10.25 percent) reflects the higher values of the DCF calculations (i.e., 9.0 percent is the top of the mean/median findings and 10.25 percent reflects the highest growth rate for the Comparison Group).

VIII. CAPITAL ASSET PRICING MODEL ANALYSIS

Q. PLEASE DESCRIBE THE THEORY AND METHODOLOGICAL BASIS OF THE CAPITAL ASSET PRICING MODEL.

A. The Capital Asset Pricing Model (CAPM) is a version of the risk premium method. The CAPM describes and measures the relationship between a security's investment risk and its market rate of return.

Q. HOW IS THE CAPM DERIVED?

A. The general form of the CAPM is:

$$K = R_f + \beta(R_m - R_f)$$

where: K = cost of equity
R_f = risk free rate
R_m = return on market
β = beta
R_m-R_f = market risk premium

As noted previously, the CAPM is a variant of the risk premium method. I believe the CAPM is generally superior to the simple risk premium method because the CAPM specifically recognizes the risk of a particular company or industry, whereas the simple risk premium method does not.

Q. WHAT GROUPS OF COMPANIES HAVE YOU UTILIZED TO PERFORM YOUR CAPM ANALYSES?

A. I have performed CAPM analyses for the same groups of utilities evaluated in my DCF analyses.

Q. WHAT RATE DID YOU USE FOR THE RISK-FREE RATE?

A. The first term of the CAPM is the risk free rate (R_f). The risk-free rate reflects the level of return which can be achieved without accepting any risk.

In reality, there is no such thing as a truly riskless asset. In CAPM applications, the risk-free rate is generally recognized by use of U.S. Treasury securities, as they are default-free because the government is able to print money and/or raise taxes to pay its debts.

Two types of Treasury securities are often utilized as the R_f component - short-term U.S. Treasury bills and long-term U.S. Treasury bonds. I have performed CAPM calculations using the three month average yield (March-May, 2007) for 20 year U.S. Treasury bonds. Over this three month period, these bonds had an average yield of 4.91 percent.

Q. WHAT BETAS DID YOU EMPLOY IN YOUR CAPM?

A. I utilized the most recent Value Line betas for each company in the groups of comparison utilities.

Q. HOW DID YOU ESTIMATE THE MARKET RISK PREMIUM COMPONENT?

A. The market risk premium component (R_m-R_f) represents the investor-expected premium of common stocks over the risk-free rate, or government bonds. For the purpose of estimating the market risk premium, I considered alternative returns of the S&P 500 (a broad-based group of large U.S. companies) and 20-year U.S. Treasury bonds.

Schedule 8 shows the return on equity for the S&P 500 group for the period 1978-2005 (all available years reported by S&P). The average return on equity for the S&P 500 group over the 1978-2005 period is 14.09 percent. This Schedule also indicates the annual yields on 20-Year U.S. Treasury bonds, as well as the annual differentials (i.e., risk premiums) between the S&P 500 and U.S. Treasury 20-Year bonds. Based upon these returns, I conclude that the risk premium is about 6.2 percent.

I have also considered the total returns for the S&P 500 group as well as for long-term government bonds, as tabulated by Ibbotson Associates, using both arithmetic and geometric means. I have considered the total returns for the entire 1926-2006 period, which are as follows:

	S&P 500	L-T Gov't Bonds	Risk Premium
Arithmetic	12.3%	5.8%	6.5%
Geometric	10.4%	5.4%	5.0%

I conclude from this that the expected risk premium is about 5.9 percent (i.e., average of all three risk premiums). I believe that a combination of arithmetic and geometric means is appropriate since investors have access to both types of means and, presumably, both types are reflected in investment decisions and thus stock prices and cost of capital.

Q. PLEASE DESCRIBE THE RESULTS OF YOUR CAPM ANALYSIS.

A. Schedule 9 shows my CAPM results. The results are as follows:

	Mean	Median
Comparison Group	10.3%	10.1%
Moul Group	9.9%	10.1%

Q. WHAT IS YOUR CONCLUSION CONCERNING THE CAPM COST OF EQUITY?

A. The CAPM results collectively indicate a cost of about 9.9 percent to 10.3 percent for the two groups of comparison utilities. I conclude that the CAPM cost of equity for the proxy groups is 10.1 percent, or the mid-point of this range.

IX. COMPARABLE EARNINGS ANALYSIS

Q. PLEASE DESCRIBE THE BASIS OF THE CE METHODOLOGY.

A. The CE method is derived from the "corresponding risk" standard of the Bluefield and Hope cases. This method is based upon the economic concept of opportunity cost. As previously noted, the cost of capital is an opportunity cost: the prospective return available to investors from alternative investments of similar risk.

The CE method is designed to measure the returns expected to be earned on the original cost book value of similar risk enterprises. Thus, this method provides a direct measure of the fair return, since it translates the competitive principle upon which regulation rests into practice.

The CE method normally examines the experienced and/or projected returns on book common equity. The logic for returns on book equity follows from the use of original cost rate base regulation for public utilities which uses a utility's book common equity to determine the cost of capital. This cost of capital is, in turn, used as the fair rate of return which is then applied to (multiplied by) the book value of rate base to establish the dollar level of capital costs to be recovered by the utility. This technique is thus consistent with the rate base methodology used to set utility rates.

Q. HOW HAVE YOU EMPLOYED THE CE METHODOLOGY IN YOUR ANALYSIS OF PPL ELECTRIC'S COMMON EQUITY COST?

A. I conducted the CE methodology by examining realized returns on equity for several groups of companies and evaluating the investor acceptance of these returns by reference to the resulting market-to-book ratios. In this manner it is possible to assess the degree to which a given level of return equates to the cost of capital. It is generally recognized for utilities that market-to-book ratios of greater than one (i.e., 100%) reflect a situation where a company is able to attract new equity capital without dilution (i.e., above book value).

I would further note that the CE analysis, as I have employed it, is based upon market data (through the use of market-to-book ratios) and is thus, essentially, a market test. As a result, my comparable earnings analysis is not subject to the criticisms occasionally made by some who maintain that past earned returns do not represent the cost of capital. In addition, my comparable earnings analysis uses prospective returns and thus is not strictly backward looking.

Q. WHAT TIME PERIODS HAVE YOU EXAMINED IN YOUR CE ANALYSIS?

A. My CE analysis considers the experienced equity returns of the comparison groups of utilities for the period 1992-2006 (i.e., last fifteen years). The comparable earnings analysis requires that I examine a relatively long period of time in order to determine trends in earnings over at least a full business cycle. Further, in estimating a fair level of return for a future period, it is important to examine earnings over a diverse period of time in order to avoid any undue influence by unusual or abnormal conditions that may occur in a single year or shorter period. Therefore, in forming my judgment of the current cost of equity I have focused on two periods: 2002-2006 (the last five years) and 1992-2001 (the most recent complete business cycle).

Q. PLEASE DESCRIBE YOUR CE ANALYSIS.

A. Schedules 10 and 11 contain summaries of experienced returns on equity for several groups of companies, while Schedule 12 presents a risk comparison of utilities versus unregulated firms.

Schedule 10 shows the earned returns on average common equity and market-to-book ratios for the two groups of comparison utilities. These can be summarized as follows:

	Historic		Prospective
Group	ROE	M/B	ROE
Comparison Group	12-1-13.7%	162-188%	12.9-13.7%
Moul Group	9.5-10.0%	131-144%	9.1-9.8%

These results indicate that historic returns of 9.5-13.7 percent have been adequate to produce market-to-book ratios of 131-188 percent for the groups of electric utilities. Furthermore, projected returns on equity for 2007, 2008 and 2010-2012 are within a range of 9.1 percent to 13.7 percent for the electric utility groups. These relate to 2006 market-to-book ratios of 141 percent or higher.

Q. HAVE YOU ALSO REVIEWED EARNINGS OF UNREGULATED FIRMS?

A. Yes. As an alternative, I also examined a group of largely unregulated firms. I have examined the Standard & Poor's 500 Composite group, since this is a well recognized group of firms that is widely utilized in the investment community and is indicative of the competitive sector of the economy. Schedule 11 presents the earned returns on equity and market-to-book ratios for the S&P 500 group over the past fourteen years (i.e., 1992-2005). As this exhibit indicates, over the two periods this group's average earned returns ranged from 12.2 percent to 14.7 percent with market-to-book ratios ranging between 299 percent and 341 percent.

Q. HOW CAN THE ABOVE INFORMATION BE USED TO ESTIMATE THE COST OF EQUITY FOR PPL ELECTRIC?

A. The recent earnings of the electric utility and S&P 500 groups can be utilized as an indication of the level of return realized and expected in the regulated and competitive sectors of the economy. In order to apply these returns to the cost of equity for comparison utilities, however, it is necessary to compare the risk levels of the electric utility industry with those of the competitive sector. I have done this in Schedule 12 which compares several risk indicators for the S&P 500 group and the utility groups. The information in this schedule indicates that the S&P 500 group is more risky than the utility comparison groups.

Q. WHAT RETURN ON EQUITY IS INDICATED BY THE CE ANALYSIS?

A. Based on the recent earnings and market-to-book ratios, I believe the CE analysis indicates that the cost of equity for comparison utilities is no more than 10 percent. Recent returns of 9.5-13.6 percent have resulted in market-to-book ratios of 131 and greater. Prospective returns of 9.1-13.7 percent have been accompanied by market-to-book ratios of over 140 percent. As a result, it is apparent that returns below this level would result in market-to-book ratios of well above 100 percent. An earned return of 10 percent or less should thus result in a market-to-book ratio of at least 100 percent.

X. RETURN ON EQUITY RECOMMENDATION

Q. PLEASE SUMMARIZE THE RESULTS OF YOUR THREE COST OF EQUITY ANALYSES.

A. My three methodologies produce the following:

Discounted Cash Flow	9.0-10.25% (9.625% mid-point)
Capital Asset Pricing Model	9.9-10.3% (10.1% mid-point)
Comparable Earnings	10.0%

My overall conclusion from these results is a range of 9 percent to 10.25 percent (9.625 percent mid-point), which focuses on the respective ranges of my individual model findings.

Q. WHAT IS YOUR COST OF EQUITY RECOMMENDATION FOR PPL ELECTRIC?

A. I recommend that PPL Electric be awarded a cost of common equity of 9.625 percent. This gives more emphasis to the DCF methodology which this Commission and other Commissions rely upon, as I do.

XI. TOTAL COST OF CAPITAL

Q. WHAT IS THE TOTAL COST OF CAPITAL FOR PPL ELECTRIC?

A. Schedule 13 reflects the total cost of capital for the Company using the Company's proposed capital structure, the Company's proposed costs of debt and preferred stock, along with my common equity cost recommendation. The resulting total cost of capital is 7.56 percent.

Q. DOES YOUR COST OF CAPITAL RECOMMENDATION PROVIDE THE COMPANY WITH A SUFFICIENT LEVEL OF EARNINGS TO MAINTAIN ITS FINANCIAL INTEGRITY?

A. Yes, it does. Schedule 14 shows the pre-tax coverage that would result if PPL Electric earned my cost of capital recommendation. As the results indicate, the mid-point of my recommended range would produce a coverage level which is within the benchmark range for an A rated utility. In addition, the debt ratio (which reflects the capital structure as proposed by the company) is within that benchmark for an A rated utility.

XII. COMMENTS ON COMPANY TESTIMONY

Q. PLEASE SUMMARIZE YOUR UNDERSTANDING OF MR. MOUL'S COST OF EQUITY ANALYSES AND RECOMMENDATIONS.

A. Mr. Moul's cost of equity analyses focus on four sets of studies, whose results are summarized below:

	Cost of Equity Findings
Discounted Cash Flow Analysis	11.01%
Risk Premium Analysis	11.50%
Capital Asset Pricing Model Analysis	12.29%
Comparable Earnings	15.05%
Average	12.46%
Median	11.90%
Mid-Point	13.03%

Mr. Moul recommends a cost of common equity for PPL Electric of 11.5 percent, which is the mid-point of his overall conclusions of 11.25 percent to 11.75 percent.

Q. DO YOU WISH TO COMMENT ON PORTIONS OF MR. MOUL'S TESTIMONY?

A. Yes. I will comment on each of the four methods Mr. Moul utilizes to determine the cost of common equity for PPL Electric.

Q. PLEASE SUMMARIZE YOUR UNDERSTANDING OF MR. MOUL'S DCF ANALYSIS.

A. Mr. Moul performs DCF analyses for a group of eight electric utilities. His results are as follows:

	Electric Group
Yield	4.29%
Growth	6.25%
Leverage	0.47%
DCF	11.01%

Q. WHAT COMMENTS DO YOU HAVE CONCERNING MR. MOUL'S GROWTH RATE RECOMMENDATION?

A. Mr. Moul recommends a 6.25 percent growth rate for his electric group. It is evident that this conclusion substantially exceeds investor expectations and is not even supported by Mr. Moul's analyses. As is indicated on Mr. Moul's Exhibit PRM-1, Schedules 9 and 10, most of the historic and projected growth rates of EPS, DPS, BVPS and cash flow per share (CFPS) are well below his recommendations. Of the eight historical growth rates he examined, only one is over 3.0 percent and five are below 2.0 percent. Further, of the eight projected long-term growth rates he considered, only one is as high as 6.25 percent and only four are over 4.0 percent. Mr. Moul's recommendation for 6.25 percent growth rate can thus only be derived by relying on two of sixteen growth indicators he examined.

Q. DO YOU HAVE ANY COMMENTS CONCERNING MR. MOUL'S PROPOSED LEVERAGE ADJUSTMENT?

A. Yes. Mr. Moul is proposing a "leverage adjustment" which is essentially an adjustment to the DCF cost rate to offset Mr. Moul's concern that "the divergence of stock prices from book values creates a conflict when the results of a market-derived cost of equity are applied to the common equity ratio measured at book value ...". Mr. Moul further claims that the existence of utility stock prices above book value creates greater financial risk for a book value capital structure versus a market value capital structure since the book value capital structure has a lower common equity ratio than the market value capital structure. As a result, Mr. Moul claims that "because the ratesetting process utilizes the book value capitalization, when computing the weighted average cost of capital, it is necessary to adjust the market-determined cost of equity for the higher financial risk related to the book value of the capitalization." Mr. Moul employs a formula to quantify the differential between the book value and market value capital structure and concludes a 0.47 percent upward adjustment to the DCF cost of equity is warranted.

I strongly disagree with Mr. Moul's proposed adjustment. Investors are well aware that electric utilities have their rates established based upon the book value of their assets (rate base) and capitalization. As a result, investors are not expecting a regulatory award on any other basis, nor should they be compensated for any difference between the book value and market value of their common equity.

I further note that, during the depressed stock price period of the 1970's and early 1980's, utility witnesses did not propose any negative leverage adjustments to lower the DCF cost of equity for the fact that utility market-to-book ratios were below 100 percent.

Q. PLEASE SUMMARIZE MR. MOUL'S RISK PREMIUM ANALYSIS.

A. Mr. Moul performs his risk premium analysis by combining the prospective yield on long-term A-rated pubic utility bonds (6.25 percent) with a 5.25 percent risk premium to derive a 11.50 percent cost of equity.

I primarily disagree with the risk premium components of Mr. Moul's risk premium method. His proposed risk premium is excessive and his conclusion thus overstates the cost of equity for PPL Electric.

Q. PLEASE COMMENT ON MR. MOUL'S 5.25 PERCENT RISK PREMIUM.

A. Mr. Moul's risk premium conclusion of 5.25 percent was developed by computing total returns (dividends/interest income plus capital gains/losses) for various classes of securities over various periods of time dating back to 1928.

Mr. Moul first averages his risk premium findings over four periods, with the following results:

1928-2006	5.37%
1952-2006	6.40%
1974-2006	5.61%
1979-2006	5.83%

In reaching the risk premium conclusion, Mr. Moul focuses on the two shorter periods (i.e., last 32 years and last 28 years) and concludes that 5.72 percent is the appropriate risk premium for the S&P Public Utilities. Based upon "differences in risk characteristics" between the S&P Public Utilities group and the electric group, he concludes that 5.25 percent is a reasonable equity risk premium for this case, which represents 92 percent of the risk premium of the S&P Utilities Group.

Mr. Moul's risk premium analyses are based on an erroneous assumption that past relationships between stock returns and bond returns are expected to prevail in the future. My Schedule 15 shows that the relationship between stock and bond returns has been very volatile over the periods examined by Mr. Moul. In fact the decade of the 1990's (most recent decade) showed an average differential (i.e., risk premium) of only 1.57 percent.

Q. PLEASE SUMMARIZE MR. MOUL'S CAPM METHODS.

A. Mr. Moul's CAPM method has the following results:

$$R_f + \beta(R_m - R_f) = k + adj. = K$$

$$5.25\% + .93 \text{ x } 6.47\% = 11.27\% + 1.02\% = 12.29\%$$

Q. DO YOU AGREE WITH MR. MOUL'S RISK-FREE RATE?

A. No. Mr. Moul's 5.25 percent risk free rate, which is based on yields on long-term U.S. Treasury bonds, exceeds both recent and current yields on these securities. My CAPM analysis shows that 20-year Treasury bonds have averaged 4.91 percent over the three-month period March-May 2007.

Q. DO YOU HAVE ANY COMMENTS CONCERNING MR. MOUL'S "LEVERAGED" BETA?

A. Yes, I do. Mr. Moul claims that "Value Line betas cannot be used directly in the CAPM unless those betas are applied to a capital structure measured with market values." He therefore employs a formula to adjust Value Line published betas to reflect tax rates and market value capital structures. The impact of this adjustment is to raise the average beta value for his electric group from 0.55 to 0.93.

I disagree with this adjustment. In essence, this is a similar adjustment to his "leverage adjustment" in his DCF analysis. The same reasons I stated in my response to this DCF adjustment apply to his CAPM leverage adjustment.

Q. PLEASE COMMENT ON MR. MOUL'S RISK PREMIUM.

A. Mr. Moul's 6.47 percent risk premium (R_m-R_f) was developed by estimating the total market forecast return for the 1,700 stocks followed by Value Line and the S&P 500 index (10.48 percent); as well as the 1926-2006 risk premium based upon the Ibbotson Associates total return (6.5 percent).

If the expected return of the 1,700 Value Line stocks, and S&P 500, is indeed 10.48 percent, then it is improper to maintain that a less risky company, such as PPL Electric, should have the same cost of equity.

Mr. Moul's second risk premium estimate – 6.5 percent from Ibbotson Associates for the period 1926-2006, has the same problems I described earlier in connection with Mr. Moul's risk premium analysis.

Q. PLEASE SUMMARIZE MR. MOUL'S COMPARABLE EARNINGS METHOD.

A. Mr. Moul's comparable earnings analysis examines the historic and forecasted returns for non-utility companies which he perceives as being of similar risk to his electric group. For these companies he calculated a 5-year historic median return on equity of 15.1 percent and a forecasted return of 15.0 percent, which average 15.05 percent – his comparable earnings conclusion.

I believe this analysis is an improper mechanism for estimating the cost of common equity for PPL Electric. The equivalence of timeliness, safety, financial strength, price stability, beta, and technical rank does not indicate that the expected earnings and cost of common equity for these non-utilities and utilities are the same. The 5-year historic and projected 3-5 year returns for the non-utilities is 15.1 percent and 15.0 percent, respectively in Mr. Moul's Schedule 14, whereas the expected returns for Mr. Moul's proxy group of electric utility companies is only 12.4 percent and 12.7 percent (my Schedule 10). This difference in returns demonstrates that utilities are able to maintain similar Value Line rankings to non-utilities while earning lower returns. This result indicates that the expected earnings for the non-utilities are greater than for utilities such as PPL Electric.

Q. HAVE YOU REVIEWED THE TESTIMONY OF PPL ELECTRIC WITNESS JULIE M. CANNELL?

A. Yes, I have. Ms. Cannell is also testifying in support of the 11.5 percent return on equity requested by PPL Electric. Her testimony focuses on the "perspective of investors."

Q. DO YOUR HAVE ANY COMMENTS CONCERNING MS. CANNELL'S TESTIMONY?

A. Yes, I do. I have a number of comments about her testimony. First, I disagree with her comment (Page 2, lines 9-11) that investors now require a higher return when investing in the electric industry.

It is apparent that the trend in allowed return for electric utilities has been downward in recent years. According to a publication by Regulatory Research Associates titled "Regulatory Focus" the average allowed return on equity established by regulatory agencies for U.S. electric utilities since 2000 has been:

Year	ROE
2000	11.43%
2001	11.09%
2002	11.16%
2003	10.97%
2004	10.75%
2005	10.54%
2006	10.36%

As this demonstrates, the trend has been downward since 2000, not upward as Ms. Cannell implies. At the same time, investors have evaluated electric utility stocks, as evidenced by the level of market-to-book ratios, as follows:

Year	Electric	Gas/Electric
2001	177%	169%
2002	141%	130%
2003	157%	148%
2004	178%	169%
2005	177%	177%
2006	202%	194%

This indicates that, from the "perspective of investors," the decline in authorized returns on equity has been expected and accepted, as evidenced by the increase in market-to-book ratios over this period.

Q. HOW DO THESE AUTHORIZED RETURNS ON EQUITY RELATE TO THE 11.5 PERCENT REQUESTED BY PPL ELECTRIC?

A. It is apparent that PPL's requested 11.5 percent return on equity is well outside the mainstream of authorized returns for other electric utilities. In fact, according to the same Regulatory Research Associates report cited above, only two 2006 authorized returns in the entire year exceeded 11.0 percent, and one of these was for a wind-generation facility.

Q. DO YOU HAVE ANY COMMENTS ON MS. CANNELL'S ASSERTION, AS MADE ON PAGES 9-12, THAT "WIRES-ONLY'" COMPANIES ARE EXPOSED TO HIGHER RISKS?

A. Yes, I do. It is obvious that Ms. Cannell's views on the risks of "wires only" companies are at odds with that of the rating agencies. I explain why below.

Q. HOW DO THE RISKS OF DISTRIBUTION AND TRANSMISSION OPERATIONS COMPARE TO THE OTHER PRIMARY OPERATIONS OF ELECTRIC UTILITIES?

A. The primary categories of the operations of electric utilities are generally described as:

- distribution;
- transmission;
- generation; and
- energy marketing and trading.

The distribution and transmission operations are often lumped together ("wires") and the generation and energy trading operations are often categorized as separate types of operations. In recent years, several electric utilities (including PPL Electric) have "divested" their generation assets, either by a sale to an independent entity or by a transfer to an unregulated entity within the holding company structure that own the utilities.

It is widely recognized by the investment community (e.g., by rating agencies) that the wires operations are less risky than the generation and energy trading operations. This lower risk associated with the wires operations relates to the regulated nature of their activities, as distinguished from the competitive nature of some generation operations (i.e., those generation operations that are no longer part of a regulated electric utility).

Q. CAN YOU PROVIDE ANY INDEPENDENT VERIFICATION OF THE LOWER RISKS THAT INVESTORS PERCEIVE FOR WIRES OPERATIONS?

A. Yes. Over the past several years, Standard & Poor's Corporation ("S&P," one of the two major debt rating agencies) has provided on-going, unambiguous analyses and descriptions of its assessment of the lower risks of the regulated wires business relative to the unregulated generation business. An early example of this occurred in 1998, when S&P instituted its initial "business position" criteria for ranking the relative business risks of companies. In a September, 1998 article titled "Rating Methodology For Global Power Utilities," S&P stated:

> Standard & Poor's utilizes business profile assessments to measure a power company's qualitative credit fundamentals. Business profiles are expressed on a scale of 1 (strong) to 10 (weak). Business profiles incorporate country risk, sector risk, and utility-specific risk.
>
> . . .
>
> Owing to the **relatively low business risk of large transmission systems and regulated distribution systems (the "wires" business),** business profile assessments for these companies should fall within the 1-4 range. The generation business is the most risky, reflecting the competitive nature of this business, and generators will generally receive business profile assessments in the mid-to lower-end of the range. (Emphasis added).

S&P has continued to express this opinion since 1999. For example, in a November 20, 2002 report titled "U.S. Power and Energy Sector Credit Slide to Continue," S&P stated:

> The industry's attention has focused on the dozen or so very large energy merchant companies and developers and their affiliates, who are ensnared in the web of collapsing financial health, disclosure misrepresentations, and accounting irregularities.

> "It would indeed by easy to see the problems of these companies as symptomatic of the entire power industry," said Standard & Poor's Director Richard Cortright, Jr. "Yet, the **credit quality** of most participants engaged in the generation, transmission, and **distribution of electricity remains healthy and regulated**." (Emphasis added).

Further, during testimony before the U.S. Senate Energy and Natural Resource Committee's hearing on the financial condition of the U.S. electricity market, S&P credit analyst Suzanne G. Smith stated:

> Historically, ratings for the electric utility industry have been investment grade (the top four categories of the rating scale, from 'AAA' to 'BBB') mainly because they were **regulated**.
>
> . . .
>
> Over the past three years, the overall credit quality of the electricity industry has declined.
>
> . . .
>
> The **introduction of competition** into the electricity market and the increased level of investment in other nonenergy related businesses, which were funded with high levels of debt, have **caused an overall decline in the industry's financial health.**
>
> . . .
>
> Since the advent of deregulation, the **industry** has **generally moved from vertically integrated utilities** to a **mix of disaggregated electrical generation companies (gencos)**, distribution companies **(discos)**, and transmission companies **(transcos)**, as well as integrated companies. They are not uniform in their financial health. **For the regulated discos, and gencos, the overall financial condition has generally remained stable.** In fact, a small number of discos and **transos actually experienced financial improvement** last year.
>
> . . .
>
> The companies that experienced the most dramatic and negative charge in financial health are those that are operating in competitive power markets; companies that have no regulated business to temper losses and financial support from a stronger parent.

"Testimony on the Financial Condition of the U.S. Electricity Market," Standard & Poor's Utilities & Perspectives, March 17, 2003, at 8 (emphasis added). Additionally, in a March 15, 2004 article titled "Keys To Success For U.S. Electricity and Distribution Companies," S&P stated:

> **Standard & Poor's** Ratings Services **views the business risk of U.S. *electric transmission and distribution (T&D) companies as generally* low relative to their integrated peers. This is attributable to the**

> **protections afforded by regulation, relatively low operating risk, and the absence of meaningful competition.** As a result, Standard & Poor's has assigned business profile scores to T&D companies in the upper range of a 10-point scale (where '1' indicates lowest risk and '10' highest risk). Nearly all T&D companies have business profile scores of between '1' and '3', but some fall below '3; and only a few will be given a '1'. Although most T&D companies are likely to be rated as strong investment grade on a stand-alone basis, based on Standard & Poor's consolidated rating methodology, ratings of some T&D companies are lower, and sometimes even below investment grade, due to the higher business risk of their parents. (Emphasis added).

Finally and significantly, on June 7, 2004, in a report titled "New Business Profile Scores Assigned For U.S. Utility And Power Companies, Financial Guidelines Revised," S&P stated:

> Standard & Poor's Ratings Services has assigned new business profile scores to U.S. utility and power companies to better reflect the relative business risk among companies in the sector.
>
> . . .
>
> Standard & Poor's has segmented the utility and power industry into sub-sectors based on the dominant corporate strategy that a company is pursuing. Standard & Poor's has published a new U.S. utility and power company ranking list that reflects these sub-sectors.
>
> . . .
>
> Since the 10-point scale was introduced, the industry has transformed into a much less homogenous industry, where the divergence of business risk – particularly regarding management, strategy, and degree of competitive market exposure – has created a much wider spectrum of risk profiles. Yet over the same period, business profile scores actually converged more tightly around a median score of '4'. The new business profile scores, as of June 2, are shown in Chart 1. The overall median business profile score is now '5'.
>
> . . .
>
> **The average business profile scores for transmission and distribution companies and transmission-only companies are lower on the scale than the previous averages,** while the average business profile scores for integrated utilities, diversified energy, and energy merchants and developers are higher. (Emphasis added).

It is very apparent that the rating agencies regard the "wires only" segment of the electric utility industry to be less risky than the generation and merchant functions. This is evidenced by the fact that PPL Electric has a S&P business profile of "3", whereas PPL has a "7" business profile.

Q. ARE YOU AWARE OF ANY STATEMENTS MADE ON BEHALF OF PPL ELECTRIC THAT RECOGNIZE THE LOWER RISK OF ITS WIRES-ONLY OPERATIONS?

A. Yes, I am. In a May 10, 2001 filing by PPL Electric for approval to issue securities (Docket No. R-00049255), the Company made the following statements:

- In order to more accurately reflect the lower business risk of a wires company, and to reduce its overall cost of capital, PPL Electric Utilities has decided to increase the amount of debt in its capital structure.

- To further reduce its operating risk and to establish an arms length separation from its affiliates, PPL Electric Utilities will solicit bids to contract with energy supplier for a generation supply agreement . . . to meet its energy needs as the POLR from 2002 through the end of 2009 . . . this action will insulate PPL Electric Utilities from its affiliates and will substantially reduce its market risks associated with volatile market power prices while PPL Electric *Utilities is subject to the generation rate cap.*

These statements, made by PPL Electric itself, clearly contradict Ms. Cannell's perceptions of the Company.

Q. HOW DOES THE RISK OF PPL ELECTRIC COMPARE TO OTHER ELECTRIC UTILITIES?

A. PPL Electric is perceived to have lower risk than other electric utilities. One prominent indicator of this is the relative bond ratings of PPL Electric. Bond ratings, as acknowledged by Ms. Cannell, are "critically important."

As Ms. Cannell notes, PPL Electric has single A bond ratings by each of the three rating agencies. According to AUS Utility Reports, only fourteen electric or gas/electric companies (including PPL) of 64 have bond ratings by both Moody's and S&P of single A or above. This means that 50 of the 64 companies have bond ratings below that of PPL Electric.

Q. MR. MOUL MAINTAINS, ON PAGE 5, THAT PPL ELECTRIC SHOULD RECEIVE THE MID-POINT OF HIS RECOMMENDED RATE OF RETURN RANGE, OR 11.5 PERCENT, IN PART DUE TO THE "EXEMPLARY

PERFORMANCE" OF THE MANAGEMENT OF THE COMPANY. HE CITES MR. DECAMPLI'S TESTIMONY AS JUSTIFICATION FOR THIS. MR. DECAMPLI, IN TURN, DESCRIBES THE "MANAGEMENT EFFECTIVENESS" OF PPL ELECTRIC AS "ONE OF SEVERAL CONSIDERATIONS" THAT SUPPORT MR. MOUL'S 11.5 PERCENT RECOMMENDATION. DO YOU HAVE ANY COMMENTS ON THIS?

A. Yes, I do. There is no justification for giving PPL Electric a higher equity return due to a perception of "exemplary" or "effective" management. To the contrary, it should be expected that management would be effective in order to be awarded a fair rate of return. The Bluefield case, in fact, cited "efficient and economical management" as an underlying assumption for granting a utility an opportunity to earn a fair rate of return. 262 U.S. at 692.

Q. PPL ELECTRIC WITNESS KRALL MAINTAINS, ON PAGES 28-33, THAT THE GOVERNOR'S ENERGY INDEPENDENCE STRATEGY HAS SEVERAL PROVISIONS THAT, IF ENACTED, "COULD INCREASE THE RISK OF REVENUE LOSS FOR PPL ELECTRIC IN SEVERAL CRITICAL AREAS. DO YOU HAVE ANY RESPONSE TO THIS ASSERTION?

A. First, I have been advised by counsel that there are numerous bills pending before the Pennsylvania House and Senate on various energy issues. It is unclear which, if any, of these pending bills will become law. It is also unclear whether the passage of any of these bills will increase or decrease the Company's relative risk or cost of capital. This is particularly true as compared to Companies in other states which have recently reexamined and amended the restructuring laws. To the extent that the Company is worried about the effects of any new law on its default service procurement, these effects will not occur until after the end of the rate caps. For PPL, it has a Commission-approved POLR procurement plan that extends to the end of 2010. This extended timeframe allows the Commission to see if the market will react positively or negatively in the future.

Second, as the name implies, the proposal is intended to enhance the energy independence of Pennsylvania and its residents/businesses. Should its provisions be used as justification for increasing retail electric rates in the State, with the sole benefactor being PPL Electric and its stockholders, this would be contrary to the intentions of the Strategy.

Q. DOES THIS COMPLETE YOUR TESTIMONY?

A. Yes, it does.

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Exhibit___(DCP-1)
Schedule 1
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BACKGROUND AND EXPERIENCE PROFILE
DAVID C. PARCELL, MBA, CRRA
EXECUTIVE VICE PRESIDENT/SENIOR ECONOMIST

EDUCATION

1985	M.B.A., Virginia Commonwealth University
1970	M.A., Economics, Virginia Polytechnic Institute and State University, (Virginia Tech)
1969	B.A., Economics, Virginia Polytechnic Institute and State University, (Virginia Tech)

POSITIONS

2007-Present	President, Technical Associates, Inc.
1995-2007	Executive Vice President and Senior Economist, Technical Associates, Inc.
1993-1995	Vice President and Senior Economist, C. W. Amos of Virginia
1972-1993	Vice President and Senior Economist, Technical Associates, Inc.
1969-1972	Research Economist, Technical Associates, Inc.
1968-1969	Research Associate, Department of Economics, Virginia Polytechnic Institute and State University

ACADEMIC HONORS

Omicron Delta Epsilon - Honor Society in Economics
Beta Gamma Sigma - National Scholastic Honor Society of Business Administration
Alpha Iota Delta - National Decision Sciences Honorary Society
Phi Kappa Phi - Scholastic Honor Society

PROFESSIONAL DESIGNATIONS

Certified Rate of Return Analyst - Founding Member
Member of Association for Investment Management and Research (AIMR)

RELEVANT EXPERIENCE

Financial Economics -- Advised and assisted many Virginia banks and savings and loan associations on organizational and regulatory matters. Testified approximately 25 times before the Virginia State Corporation Commission and the Regional Administrator of National Banks on matters related to branching and organization for banks, savings and loan associations, and consumer finance companies.

Advised financial institutions on interest rate structure and loan maturity. Testified before Virginia State Corporation Commission on maximum rates for consumer finance companies.

Testified before several committees and subcommittees of Virginia General Assembly on numerous banking matters.

Clients have included First National Bank of Rocky Mount, Patrick Henry National Bank, Peoples Bank of Danville, Blue Ridge Bank, Bank of Essex, and Signet Bank.

Published articles in law reviews and other periodicals on structure and regulation of banking/financial services industry.

Utility Economics -- Performed numerous financial studies of regulated public utilities. Testified in over 300 cases before some thirty state and federal regulatory agencies.

Prepared numerous rate of return studies incorporating cost of equity determination based on DCF, CAPM, comparable earnings and other models. Developed procedures for identifying differential risk characteristics by nuclear construction and other factors.

Conducted studies with respect to cost of service and indexing for determining utility rates, the development of annual review procedures for regulatory control of utilities, fuel and power plant cost recovery adjustment clauses, power supply agreements among affiliates, utility franchise fees, and use of short-term debt in capital structure.

Presented expert testimony before federal regulatory agencies Federal Energy Regulatory Commission, Federal Power Commission, and National Energy Board (Canada), state regulatory agencies in Alabama, Alaska, Arizona, California, Connecticut, Delaware, District of Columbia, Florida, Georgia, Hawaii, Illinois, Indiana, Kansas, Kentucky, Maine, Maryland, Missouri, Nebraska, Nevada, New Mexico, Ohio, Oklahoma, Ontario (Canada), Pennsylvania, South Carolina, Texas, Utah, Vermont, Virginia, West Virginia, Washington, Wisconsin, and Yukon Territory (Canada).

Published articles in law reviews and other periodicals on the theory and purpose of regulation and other regulatory subjects.

Clients served include state regulatory agencies in Alaska, Arizona, Delaware, Missouri, North Carolina, Ontario (Canada), and Virginia; consumer advocates and attorneys general in Alabama, Arizona, District of Columbia, Florida, Georgia, Hawaii, Illinois, Indiana, Kansas, Kentucky, Maryland, Nevada, New Mexico, Ohio, Oklahoma, Pennsylvania, South Carolina, Texas, Utah, Vermont, Virginia, and West Virginia; federal agencies including Defense Communications Agency, the Department of Energy, Department of the Navy, and General Services Administration; and various organizations such as Bath Iron Works, Illinois Citizens' Utility Board, Illinois Governor's

Office of Consumer Services, Illinois Small Business Utility Advocate, Wisconsin's Environmental Decade, Wisconsin's Citizens Utility Board, and Old Dominion Electric Cooperative.

Insurance Economics -- Conducted analyses of the relationship between the investment income earned by insurance companies on their portfolios and the premiums charged for insurance. Analyzed impact of diversification on financial strength of Blue Cross/Blue Shield Plans in Virginia.

Conducted studies of profitability and cost of capital for property/casualty insurance industry. Evaluated risk of and required return on surplus for various lines of insurance business.

Presented expert testimony before Virginia State Corporation Commission concerning cost of capital and expected gains from investment portfolio. Testified before insurance bureaus of Maine, New Jersey, North Carolina, Rhode Island, South Carolina and Vermont concerning cost of equity for insurance companies.

Prepared cost of capital and investment income return analyses for numerous insurance companies concerning several lines of insurance business. Analyses used by Virginia Bureau of Insurance for purposes of setting rates.

Special Studies -- Conducted analyses which evaluated the financial and economic implications of legislative and administrative changes. Subject matter of analyses include returnable bottles, retail beer sales, wine sales regulations, taxi-cab taxation, and bank regulation. Testified before several Virginia General Assembly subcommittees.

Testified before Virginia ABC Commission concerning economic impact of mixed beverage license.

Clients include Virginia Beer Wholesalers, Wine Institute, Virginia Retail Merchants Association, and Virginia Taxicab Association.

Franchise, Merger & Anti-Trust Economics -- Conducted studies on competitive impact on market structures due to joint ventures, mergers, franchising and other business restructuring. Analyzed the costs and benefits to parties involved in mergers. Testified in federal courts and before banking and other regulatory bodies concerning the structure and performance of markets, as well as on the impact of restrictive practices.

Clients served include Dominion Bankshares, asphalt contractors, and law firms.

Transportation Economics -- Conducted cost of capital studies to assess profitability of oil pipelines, trucks, taxicabs and railroads. Analyses have been presented before the Federal Energy Regulatory Commission and Alaska Pipeline Commission in rate proceedings. Served as a consultant to the Rail Services Planning Office on the reorganization of rail services in the U.S.

Economic Loss Analyses -- Testified in federal courts, state courts, and other adjudicative forums regarding the economic loss sustained through personal and business injury whether due to bodily harm, discrimination, non-performance, or anticompetitive practices. Testified on economic loss to a commercial bank resulting from publication of adverse information concerning solvency. Testimony has been presented on behalf of private individuals and business firms.

MEMBERSHIPS

American Economic Association
Virginia Association of Economists
Richmond Society of Financial Analysts
Financial Analysts Federation
Society of Utility and Regulatory Financial Analysts

Board of Directors	1992-2000
Secretary/Treasurer	1994-1998
President	1998-2000

RESEARCH ACTIVITY

Books and Major Research Reports

"Stock Price As An Indicator of Performance," Master of Arts Thesis, Virginia Tech, 1970

"Revision of the Property and Casualty Insurance Ratemaking Process Under Prior Approval in the Commonwealth of Virginia," prepared for the Bureau of Insurance of the Virginia State Corporation Commission, with Charles Schotta and Michael J. Ileo, 1971

"An analysis of the Virginia Consumer Finance Industry to Determine the Need for Restructuring the Rate and Size Ceilings on Small Loans in Virginia and the Process by which They are Governed," prepared for the Virginia Consumer Finance Association, with Michael J. Ileo, 1973

State Banks and the State Corporation Commission: A Historical Review, Technical Associates, Inc., 1974

"A Study of the Implications of the Sale of Wine by the Virginia Department of Alcoholic Beverage Control", prepared for the Virginia Wine Wholesalers Association, Virginia Retail Merchants Association,
Virginia Food Dealers Association, Virginia Association of Chain Drugstores, Southland Corporation, and the Wine Institute, 1983.

"Performance and Diversification of the Blue Cross/Blue Shield Plans in Virginia: An Operational Review", prepared for the Bureau of Insurance of the Virginia State Corporation Commission, with Michael J. Ileo and Alexander F. Skirpan, 1988.

The Cost of Capital - A Practitioners' Guide, Society of Utility and Regulatory Financial Analysts, 1997 (previous editions in 1991, 1992, 1993, 1994, and 1995).

Papers Presented and Articles Published

"The Differential Effect of Bank Structure on the Transmission of Open Market Operations," Western Economic Association Meeting, with Charles Schotta, 1971

"The Economic Objectives of Regulation: The Trend in Virginia," (with Michael J. Ileo), William and Mary Law Review, Vol. 14, No. 2, 1973

"Evolution of the Virginia Banking Structure, 1962-1974: The Effects of the Buck-Holland Bill", (with Michael J. Ileo), William and Mary Law Review, Vol. 16, No. 3, 1975

"Banking Structure and Statewide Branching: The Potential for Virginia", William and Mary Law Review, Vol. 18, No. 1, 1976

"Bank Expansion and Electronic Banking: Virginia Banking Structure Changes Past, Present, and Future," William and Mary Business Review," Vol. 1, No. 2, 1976

"Electronic Banking - Wave of the Future?" (with James R. Marchand), Journal of Management and Business Consulting, Vol. 1, No. 1, 1976

"The Pricing of Electricity" (with James R. Marchand), Journal of Management and Business Consulting, Vol. 1, No. 2, 1976

"The Public Interest - Bank and Savings and Loan Expansion in Virginia" (with Richard D. Rogers), University of Richmond Law Review, Vol. 11, No. 3, 1977

"When Is It In the 'Public Interest' to Authorize a New Bank?", University of Richmond Law Review, Vol. 13, No. 3, 1979

"Banking Deregulation and Its Implications on the Virginia Banking Structure," William and Mary Business Review, Vol. 5, No. 1, 1983

"The Impact of Reciprocal Interstate Banking Statutes on The Performance of Virginia Bank Stocks", with William B. Harrison, Virginia Social Science Journal, Vol. 23, 1988.

"The Financial Performance of New Banks in Virginia", Virginia Social Science Journal, Vol. 24, 1989

"Identifying and Managing Community Bank Performance After Deregulation", with William B. Harrison, Journal of Managerial Issues, Vol. II, No. 2, Summer 1990

"The Flotation Cost Adjustment To Utility Cost of Common Equity - Theory, Measurement and Implementation," presented at Twenty-Fifth Financial Forum, National Society of Rate of Return Analysts, Philadelphia, Pennsylvania, April 28, 1993.

Biography of Myon Edison Bristow, Dictionary of Virginia Biography, Volume 2, 2001.

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ECONOMIC INDICATORS

YEAR	REAL GDP GROWTH	IND PROD GROWTH	UNEMP RATE	CPI	PPI
			1975 - 1982 Cycle.		
1975	-1.1%	-8.9%	8.5%	7.0%	6.6%
1976	5.4%	10.8%	7.7%	4.8%	3.7%
1977	5.5%	5.9%	7.0%	6.8%	6.9%
1978	5.0%	5.7%	6.0%	9.0%	9.2%
1979	2.8%	4.4%	5.8%	13.3%	12.8%
1980	-0.2%	-1.9%	7.0%	12.4%	11.8%
1981	1.8%	1.9%	7.5%	8.9%	7.1%
1982	-2.1%	-4.4%	9.5%	3.8%	3.6%
			1983 - 1991 Cycle		
1983	4.0%	3.7%	9.5%	3.8%	0.6%
1984	6.8%	9.3%	7.5%	3.9%	1.7%
1985	3.7%	1.7%	7.2%	3.8%	1.8%
1986	3.1%	0.9%	7.0%	1.1%	-2.3%
1987	2.9%	4.9%	6.2%	4.4%	2.2%
1988	3.8%	4.5%	5.5%	4.4%	4.0%
1989	3.5%	1.8%	5.3%	4.6%	4.9%
1990	1.8%	-0.2%	5.6%	6.1%	5.7%
1991	-0.5%	-2.0%	6.8%	3.1%	-0.1%
			1992 - 2001 Cycle		
1992	3.0%	3.1%	7.5%	2.9%	1.6%
1993	2.7%	3.3%	6.9%	2.7%	0.2%
1994	4.0%	5.4%	6.1%	2.7%	1.7%
1995	2.5%	4.8%	5.6%	2.5%	2.3%
1996	3.7%	4.3%	5.4%	3.3%	2.8%
1997	4.5%	7.2%	4.9%	1.7%	-1.2%
1998	4.2%	6.1%	4.5%	1.6%	0.0%
1999	4.5%	4.7%	4.2%	2.7%	2.9%
2000	3.7%	4.5%	4.0%	3.4%	3.6%
2001	0.8%	-3.5%	4.7%	1.6%	-1.6%
			Current Cycle		
2002	1.6%	0.0%	5.8%	2.4%	1.2%
2003	2.5%	1.1%	6.0%	1.9%	4.0%
2004	3.9%	2.5%	5.5%	3.3%	4.2%
2005	3.2%	3.2%	5.1%	3.4%	5.4%
2006	3.3%	3.9%	4.6%	2.5%	1.1%
2002					
1st Qtr.	2.7%	-3.8%	5.6%	2.8%	4.4%
2nd Qtr.	2.2%	-1.2%	5.9%	0.9%	-2.0%
3rd Qtr.	2.4%	0.8%	5.8%	2.4%	1.2%
4th Qtr.	0.2%	1.4%	5.9%	1.6%	0.4%
2003					
1st Qtr.	1.2%	1.1%	5.8%	4.8%	5.6%
2nd Qtr.	3.5%	-0.9%	6.2%	0.0%	-0.5%
3rd Qtr.	7.5%	-0.9%	6.1%	3.2%	3.2%
4th Qtr.	2.7%	1.5%	5.9%	-0.3%	2.8%
2004					
1st Qtr.	3.9%	2.8%	5.6%	5.2%	5.2%
2nd Qtr.	4.0%	4.9%	5.6%	4.4%	4.4%
3rd Qtr.	3.1%	4.6%	5.4%	0.8%	0.8%
4th Qtr.	2.6%	4.3%	5.4%	3.6%	7.2%
2005					
1st Qtr.	3.4%	3.8%	5.3%	4.4%	5.6%
2nd Qtr.	3.3%	3.0%	5.1%	1.6%	-0.4%
3rd Qtr.	4.2%	2.7%	5.0%	8.8%	14.0%
4th Qtr.	1.8%	3.1%	4.9%	-2.0%	4.0%
2006					
1st Qtr.	5.6%	3.4%	4.7%	4.8%	-0.2%
2nd Qtr.	2.6%	4.5%	4.6%	4.8%	5.6%
3rd Qtr.	2.0%	5.2%	4.7%	0.4%	-4.4%
4th Qtr.	2.5%	3.5%	4.5%	0.0%	3.6%
2007					
1st Qtr.	0.6%	2.5%	4.5%	4.8%	6.8%

Source: Council of Economic Advisors, Economic Indicators, various issues.

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Schedule 2
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INTEREST RATES

YEAR	PRIME RATE	US TREAS T BILLS 3 MONTH	US TREAS T BONDS 10 YEAR	UTILITY BONDS Aaa	UTILITY BONDS Aa	UTILITY BONDS A	UTILITY BONDS Baa
1975 - 1982 Cycle							
1975	7.86%	5.84%	7.99%	9.03%	9.44%	10.09%	10.96%
1976	6.84%	4.99%	7.61%	8.63%	8.92%	9.29%	9.82%
1977	6.83%	5.27%	7.42%	8.19%	8.43%	8.61%	9.06%
1978	9.06%	7.22%	8.41%	8.87%	9.10%	9.29%	9.62%
1979	12.67%	10.04%	9.44%	9.86%	10.22%	10.49%	10.96%
1980	15.27%	11.51%	11.46%	12.30%	13.00%	13.34%	13.95%
1981	18.89%	14.03%	13.93%	14.64%	15.30%	15.95%	16.60%
1982	14.86%	10.69%	13.00%	14.22%	14.79%	15.86%	16.45%
1983 - 1991 Cycle							
1983	10.79%	8.63%	11.10%	12.52%	12.83%	13.66%	14.20%
1984	12.04%	9.58%	12.44%	12.72%	13.66%	14.03%	14.53%
1985	9.93%	7.48%	10.62%	11.68%	12.06%	12.47%	12.96%
1986	8.33%	5.98%	7.68%	8.92%	9.30%	9.58%	10.00%
1987	8.21%	5.82%	8.39%	9.52%	9.77%	10.10%	10.53%
1988	9.32%	6.69%	8.85%	10.05%	10.26%	10.49%	11.00%
1989	10.87%	8.12%	8.49%	9.32%	9.56%	9.77%	9.97%
1990	10.01%	7.51%	8.55%	9.45%	9.65%	9.86%	10.06%
1991	8.46%	5.42%	7.86%	8.85%	9.09%	9.36%	9.55%
1992 - 2001 Cycle							
1992	6.25%	3.45%	7.01%	8.19%	8.55%	8.69%	8.86%
1993	6.00%	3.02%	5.87%	7.29%	7.44%	7.59%	7.91%
1994	7.15%	4.29%	7.09%	8.07%	8.21%	8.31%	8.63%
1995	8.83%	5.51%	6.57%	7.68%	7.77%	7.89%	8.29%
1996	8.27%	5.02%	6.44%	7.48%	7.57%	7.75%	8.16%
1997	8.44%	5.07%	6.35%	7.43%	7.54%	7.60%	7.95%
1998	8.35%	4.81%	5.26%	6.77%	6.91%	7.04%	7.26%
1999	8.00%	4.66%	5.65%	7.21%	7.51%	7.62%	7.88%
2000	9.23%	5.85%	6.03%	7.88%	8.06%	8.24%	8.36%
2001	6.91%	3.45%	5.02%	7.47%	7.59%	7.78%	8.02%
Current Cycle							
2002	4.67%	1.62%	4.61%		7.19%	7.37%	8.02%
2003	4.12%	1.02%	4.01%		6.40%	6.58%	6.84%
2004	4.34%	1.38%	4.27%		6.04%	6.16%	6.40%
2005	6.19%	3.16%	4.29%		5.44%	5.65%	5.93%
2006	7.96%	4.73%	4.80%		5.84%	6.07%	6.32%

Sources: Council of Economic Advisors, Economic Indicators; Moody's Bond Record; Federal Reserve Bulletin; various issues.

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INTEREST RATES

YEAR	PRIME RATE	US TREAS T BILLS 3 MONTH	US TREAS T BONDS 10 YEAR	UTILITY BONDS Aaa	UTILITY BONDS Aa	UTILITY BONDS A	UTILITY BONDS Baa
2003							
Jan	4.25%	1.17%	4.05%		6.87%	7.06%	7.47%
Feb	4.25%	1.16%	3.90%		6.66%	6.93%	7.17%
Mar	4.25%	1.13%	3.81%		6.56%	6.79%	7.05%
Apr	4.25%	1.14%	3.96%		6.47%	6.64%	6.94%
May	4.25%	1.08%	3.57%		6.20%	6.36%	6.47%
June	4.00%	0.95%	3.33%		6.12%	6.21%	6.30%
July	4.00%	0.90%	3.98%		6.37%	6.57%	6.67%
Aug	4.00%	0.96%	4.45%		6.48%	6.78%	7.08%
Sept	4.00%	0.95%	4.27%		6.30%	6.56%	6.87%
Oct	4.00%	0.93%	4.29%		6.28%	6.43%	6.79%
Nov	4.00%	0.94%	4.30%		6.26%	6.37%	6.69%
Dec	4.00%	0.90%	4.27%		6.18%	6.27%	6.61%
2004							
Jan	4.00%	0.89%	4.15%		6.06%	6.15%	6.47%
Feb	4.00%	0.92%	4.08%		6.10%	6.15%	6.28%
Mar	4.00%	0.94%	3.83%		5.93%	5.97%	6.12%
Apr	4.00%	0.94%	4.35%		6.33%	6.35%	6.46%
May	4.00%	1.04%	4.72%		6.66%	6.62%	6.75%
June	4.00%	1.27%	4.73%		6.30%	6.46%	6.84%
July	4.25%	1.35%	4.50%		6.09%	6.27%	6.67%
Aug	4.50%	1.48%	4.28%		5.95%	6.14%	6.45%
Sept	4.75%	1.65%	4.13%		5.79%	5.98%	6.27%
Oct	4.75%	1.75%	4.10%		5.74%	5.94%	6.17%
Nov	5.00%	2.06%	4.19%		5.79%	5.97%	6.16%
Dec	5.25%	2.20%	4.23%		5.78%	5.92%	6.10%
2005							
Jan	5.25%	2.32%	4.22%		5.68%	5.78%	5.95%
Feb	5.50%	2.53%	4.17%		5.55%	5.61%	5.76%
Mar	5.75%	2.75%	4.50%		5.76%	5.83%	6.01%
Apr	5.75%	2.79%	4.34%		5.56%	5.64%	5.95%
May	6.00%	2.86%	4.14%		5.39%	5.53%	5.88%
June	6.25%	2.99%	4.00%		5.05%	5.40%	5.70%
July	6.25%	3.22%	4.18%		5.18%	5.51%	5.81%
Aug	6.50%	3.45%	4.26%		5.23%	5.50%	5.80%
Sept	6.75%	3.47%	4.20%		5.27%	5.52%	5.83%
Oct	6.75%	3.70%	4.46%		5.50%	5.79%	6.08%
Nov	7.00%	3.90%	4.54%		5.59%	5.88%	6.19%
Dec	7.25%	3.89%	4.47%		5.55%	5.80%	6.14%
2006							
Jan	7.50%	4.20%	4.42%		5.50%	5.75%	6.06%
Feb	7.50%	4.41%	4.57%		5.55%	5.82%	6.11%
Mar	7.75%	4.51%	4.72%		5.71%	5.98%	6.26%
Apr	7.75%	4.59%	4.99%		6.02%	6.29%	6.54%
May	8.00%	4.72%	5.11%		6.16%	6.42%	6.59%
June	8.25%	4.79%	5.11%		6.16%	6.40%	6.61%
July	8.25%	4.96%	5.09%		6.13%	6.37%	6.61%
Aug	8.25%	4.98%	4.88%		5.97%	6.20%	6.43%
Sept	8.25%	4.82%	4.72%		5.81%	6.00%	6.26%
Oct	8.25%	4.89%	4.73%		5.80%	5.98%	6.24%
Nov	8.25%	4.94%	4.60%		5.61%	5.80%	6.04%
Dec		4.85%	4.56%		5.62%	5.81%	6.05%
2007							
Jan	8.25%	4.98%	4.76%		5.78%	5.96%	6.16%
Feb	8.25%	5.03%	4.72%		5.73%	5.90%	6.10%
Mar	8.25%	4.94%	4.56%		5.66%	5.85%	6.10%
Apr	8.25%	4.88%	4.69%		5.83%	5.97%	6.24%
May	8.25%	4.77%	4.75%		5.86%	5.99%	6.23%

Sources: Council of Economic Advisors, Economic Indicators; Moody's Bond Record; Federal Reserve Bulletin; various issues.

STOCK PRICE INDICATORS

YEAR	S&P Composite	Nasdaq Composite	DJIA	S&P D/P	S&P E/P
			1975 - 1982 Cycle		
1975			802.49	4.31%	9.15%
1976			974.92	3.77%	8.90%
1977			894.63	4.62%	10.79%
1978			820.23	5.28%	12.03%
1979			844.40	5.47%	13.46%
1980			891.41	5.26%	12.66%
1981			932.92	5.20%	11.96%
1982			884.36	5.81%	11.60%
			1983 - 1991 Cycle		
1983			1,190.34	4.40%	8.03%
1984			1,178.48	4.64%	10.02%
1985			1,328.23	4.25%	8.12%
1986			1,792.76	3.49%	6.09%
1987			2,275.99	3.08%	5.48%
1988			2,060.82	3.64%	8.01%
1989	322.84		2,508.91	3.45%	7.41%
1990	334.59		2,678.94	3.61%	6.47%
1991	376.18	491.69	2,929.33	3.24%	4.79%
			1992 - 2001 Cycle		
1992	415.74	599.26	3,284.29	2.99%	4.22%
1993	451.21	715.16	3,522.06	2.78%	4.46%
1994	460.42	751.65	3,793.77	2.82%	5.83%
1995	541.72	925.19	4,493.76	2.56%	6.09%
1996	670.50	1,164.96	5,742.89	2.19%	5.24%
1997	873.43	1,469.49	7,441.15	1.77%	4.57%
1998	1,085.50	1,794.91	8,625.52	1.49%	3.46%
1999	1,327.33	2,728.15	10,464.88	1.25%	3.17%
2000	1,427.22	3,783.67	10,734.90	1.15%	3.63%
2001	1,194.18	2,035.00	10,189.13	1.32%	2.95%
			Current Cycle		
2002	993.94	1,539.73	9,226.43	1.61%	2.92%
2003	965.23	1,647.17	8,993.59	1.77%	3.84%
2004	1,130.65	1,986.53	10,317.39	1.72%	4.89%
2005	1,207.23	2,099.32	10,547.67	1.83%	5.36%
2006	1,310.46	2,263.41	11,408.67	1.87%	5.78%
2002					
1st Qtr.	1,131.56	1,879.85	10,105.27	1.39%	2.15%
2nd Qtr.	1,068.45	1,641.53	9,912.70	1.49%	2.70%
3rd Qtr.	894.65	1,308.17	8,487.59	1.76%	3.68%
4th Qtr.	887.91	1,346.07	8,400.17	1.79%	3.14%
2003					
1st Qtr.	860.03	1,350.44	8,122.83	1.89%	3.57%
2nd Qtr.	938.00	1,521.92	8,684.52	1.75%	3.55%
3rd Qtr.	1,000.50	1,765.96	9,310.57	1.74%	3.87%
4th Qtr.	1,056.42	1,934.71	9,856.44	1.69%	4.38%
2004					
1st Qtr.	1,133.29	2,041.95	10,488.43	1.64%	4.62%
2nd Qtr.	1,122.87	1,984.13	10,289.04	1.71%	4.92%
3rd Qtr.	1,104.15	1,872.90	10,129.85	1.79%	5.18%
4th Qtr.	1,162.07	2,050.22	10,362.25	1.75%	4.83%
2005					
1st Qtr.	1,191.98	2,056.01	10,648.48	1.77%	5.11%
2nd Qtr.	1,181.65	2,012.24	10,382.35	1.85%	5.32%
3rd Qtr.	1,224.14	2,149.20	10,544.06	1.83%	5.42%
4th Qtr	1,230.47	2,178.67	10,615.78	1.86%	5.60%
2006					
1st Qtr.	1,283.04	2,287.97	10,996.04	1.85%	5.61%
2nd Qtr.	1,281.77	2,240.46	11,188.84	1.90%	5.88%
3rd Qtr.	1,288.40	2,141.97	11,584.69	1.91%	5.88%
4th Qtr	1,389.48	2,390.26	12,175.30	1.81%	5.75%
2007					
1st Qtr.	1,425.30	2,444.85	12,470.97	1.84%	5.86%

Source: Council of Economic Advisors, Economic Indicators, various issues.

Exhibit___(DCP-1)
Schedule 3

PPL CORPORATION
SEGMENT FINANCIAL INFORMATION
2004 - 2006
($millions)

Segment	Revenue	Net Income	Total Assets
		2004	
Supply	$1,783	$421	
	31.0%	60.3%	
International Delivery	$1,102	$197	
	19.2%	28.2%	
Pennsylvania Delivery	$2,869	$80	
	49.9%	11.5%	
Total	$5,754	$698	
		2005	
Supply	$1,774	$311	$7,118
	28.7%	45.9%	39.7%
International Delivery	$1,206	$215	$5,089
	19.5%	31.7%	28.4%
Pennsylvania Delivery	$3,199	$152	$5,719
	51.8%	22.4%	31.9%
Total	$6,179	$678	$17,926
		2006	
Supply	$2,239	$416	$8,039
	32.5%	48.1%	40.7%
International Delivery	$1,347	$268	$6,208
	19.5%	31.0%	31.4%
Pennsylvania Delivery	$3,313	$181	$5,500
	48.0%	20.9%	27.9%
Total	$6,899	$865	$19,747

Source: PPL Corporation Annual Report.

Exhibit___(DCP-1)
Schedule 4
Page 1 of 2

PPL ELECTRIC UTILITIES CORPORATION
CAPITAL STRUCTURE RATIOS
2002 - 2006
($millions)

YEAR	COMMON EQUITY	PREFERRED SECURITIES	LONG-TERM DEBT	SHORT-TERM DEBT
2002	$1,142.6	$79.0	$1,479.2	$14.7
	42.1%	2.9%	54.5%	0.5%
	42.3%	2.9%	54.8%	
2003	$1,216.8	$48.3	$1,493.4	$0.0
	44.1%	1.8%	54.1%	0.0%
	44.1%	1.8%	54.1%	
2004	$1,262.5	$48.7	$1,358.1	$42.0
	46.6%	1.8%	50.1%	1.5%
	47.3%	1.8%	50.9%	
2005	$1,322.6	$52.1	$1,519.4	$42.0
	45.0%	1.8%	51.7%	1.4%
	45.7%	1.8%	52.5%	
2006	$1,219.1	$299.5	$1,341.6	$42.0
	42.0%	10.3%	46.2%	1.4%
	42.6%	10.5%	46.9%	

Note: Percentages may not total 100.0% due to rounding.

Sources: Response to Interrogatories of the Office of Consumer Advocate, Set II, Q. 6, and information contained in Company filing.

Exhibit___(DCP-1)
Schedule 4
Page 2 of 2

PPL CORPORATION
CAPITAL STRUCTURE RATIOS
2001 - 2006
($millions)

YEAR	COMMON EQUITY	PREFERRED SECURITIES	LONG-TERM DEBT	SHORT-TERM DEBT
2002	$2,724.5	$79.0	$4,575.4	$942.7
	32.7%	0.9%	55.0%	11.3%
	36.9%	1.1%	62.0%	
2003	$3,622.3	$48.3	$7,100.3	$56.1
	33.5%	0.4%	65.6%	0.5%
	33.6%	0.4%	65.9%	
2004	$4,613.1	$48.7	$6,578.1	$42.2
	40.9%	0.4%	58.3%	0.4%
	41.0%	0.4%	58.5%	
2005	$4,418.0	$51.0	$5,955.0	$214.0
	41.5%	0.5%	56.0%	2.0%
	42.4%	0.5%	57.1%	
2006	$5,122.0	$301.0	$6,728.0	$42.0
	42.0%	2.5%	55.2%	0.3%
	42.2%	2.5%	55.4%	

Note: Percentages may not total 100.0% due to rounding.

Sources: Response to Interrogatories of the Office of Consumer Advocate, Set II, Q. 6 and Annua Report of PPL Corp.

Exhibit___(DCP-1)
Schedule 5

AUS UTILITY REPORTS
ELECTRIC UTILITY GROUPS
AVERAGE COMMON EQUITY RATIOS

Year	Electric	Combination Electric and Gas
2002	38%	36%
2003	42%	38%
2004	47%	43%
2005	44%	47%
2006	45%	44%

Note: Averages include short-term debt.

Source: AUS Utility Reports.

Exhibit___(DCP-1)
Schedule 6

COMPARISON COMPANIES
BASIS FOR SELECTION

Company	Market Cap (000)	Percent Revenues Electric	Common Equity Ratio	Value Line Safety	Moody's/ S&P Bond Rating	S&P Stock Ranking
PPL Corp	$14,000	66%	42%	2	A- / A3	B+
Comparison Group*						
Ameren Corp.	$10,400	81%	54%	2	BBB / Baa1	A-
American Electric Power Company	$19,000	94%	45%	3	BBB / Baa1	B
Consolidated Edison, Inc.	$12,600	63%	49%	1	A / A1	B+
Edison International	$17,000	78%	41%	3	BBB+ / Baa1	B
Entergy Corp.	$21,100	83%	46%	2	BBB- / Baa2	A-
Exelon Corp.	$43,000	67%	44%	1	BBB / Baa1	B+
Firstenergy Corp.	$20,000	85%	52%	2	BBB / Baa1	B+
FPL Group, Inc.	$24,200	76%	51%	1	A / AA3	A-
Progress Energy	$12,700	86%	43%	2	BBB / A3	B
Public Service Enterprise Group, Inc.	$18,800	61%	35%	3	A- / A3	B+
Southern Company	$27,000	98%	44%	1	BBB / A3	A-

* Selected using following criteria:
Market cap of $10 billion or greater.
Electric Revenues of 40% or greater.
Common Equity Ratio of 35% or greater.
Value Line Safety of 1, 2 or 3.
S&P bond ratings of A/BBB and Moody's bond ratings of A/Baa.
S&P stock ranking of B or B+ or A-.

Sources: C.A. Turner Utility Reports, Standard & Poor's Stock Guide, Value Line Investment Survey.

Exhibit___(DCP-1)
Schedule 7

COMPARISON COMPANIES
DIVIDEND YIELD

COMPANY	DPS	March-May 2007 Stock Prices HIGH	LOW	AVERAGE	YIELD
Comparison Group					
Ameren Corp.	$2.54	$55.00	$48.56	$51.78	4.9%
American Electric Power Company	$1.56	$49.47	$48.66	$49.07	3.2%
Consolidated Edison, Inc.	$2.32	$52.90	$47.46	$50.18	4.6%
Edison International	$1.16	$58.71	$46.20	$52.46	2.2%
Entergy Corp.	$2.16	$120.47	$95.18	$107.83	2.0%
Exelon Corp.	$1.76	$79.38	$63.60	$71.49	2.5%
Firstenergy Corp.	$2.00	$72.90	$60.85	$66.88	3.0%
FPL Group, Inc.	$0.00	$66.24	$56.50	$61.37	0.0%
PPL Corp	$1.22	$46.42	$37.03	$41.73	2.9%
Progress Energy	$2.44	$52.69	$47.87	$50.28	4.9%
Public Service Enterprise Group, Inc.	$2.34	$93.80	$72.87	$83.34	2.8%
Southern Company	$1.61	$38.90	$34.85	$36.88	4.4%
Average					**3.1%**
Moul Electric Group					
CH Energy Group, Inc.	$2.16	$50.78	$45.93	$48.36	4.5%
Central Vermont Public Service Corp	$0.92	$36.33	$24.37	$30.35	3.0%
Consolidated Edison, Inc.	$2.32	$52.90	$47.46	$50.18	4.6%
Energy East Corp.	$1.20	$25.40	$23.76	$24.58	4.9%
Northeast Utilities	$0.75	$33.62	$28.20	$30.91	2.4%
NSTAR	$1.30	$37.37	$33.36	$35.37	3.7%
Pepco Holdings, Inc.	$1.04	$30.71	$25.85	$28.28	3.7%
UIL Holdings	$1.73	$37.01	$32.80	$34.91	5.0%
Average					**4.0%**

Source: Yahoo! Finance.

Exhibit___(DCP-
Schedule 7
Page 2 of 4

COMPARISON COMPANIES
RETENTION GROWTH RATES

COMPANY	2002	2003	2004	2005	2006	Average	2007	2008	2010-12	Average
Comparison Group										
Ameren Corp.	0.2%	2.2%	0.9%	1.7%	0.5%	1.1%	1.5%	1.5%	2.0%	1.7%
American Electric Power Company	2.4%	4.5%	5.7%	5.2%	5.7%	4.7%	5.5%	5.0%	5.5%	5.3%
Consolidated Edison, Inc.	4.0%	2.9%	0.8%	2.6%	2.0%	2.5%	2.5%	2.5%	2.5%	2.5%
Edison International	11.9%	13.6%	0.0%	12.3%	10.1%	9.6%	8.0%	7.5%	6.0%	7.2%
Entergy Corp.	7.1%	5.6%	5.8%	6.0%	7.0%	6.3%	9.5%	8.5%	7.0%	8.3%
Exelon Corp.	12.8%	11.5%	10.7%	11.9%	13.0%	12.0%	14.5%	14.5%	11.5%	13.5%
Firstenergy Corp.	4.3%	0.0%	4.9%	4.2%	7.5%	4.2%	7.5%	7.5%	7.0%	7.3%
FPL Group, Inc.	4.6%	6.4%	5.6%	4.0%	7.0%	5.5%	7.0%	7.0%	6.5%	6.8%
PPL Corp	12.4%	11.7%	9.3%	8.8%	9.5%	10.3%	8.0%	7.0%	10.0%	8.3%
Progress Energy	5.0%	3.7%	2.6%	1.7%	0.5%	2.7%	1.0%	1.5%	2.0%	1.5%
Public Service Enterprise Group, Inc.	8.3%	6.5%	3.5%	5.2%	5.5%	5.8%	8.5%	8.0%	7.0%	7.8%
Southern Company	4.7%	5.0%	5.9%	6.2%	4.0%	5.2%	4.0%	3.5%	3.5%	3.7%
Average						**5.8%**				**6.2%**
Moul Electric Group										
CH Energy Group, Inc.	0.0%	2.0%	1.7%	2.0%	1.5%	1.4%	1.5%	1.5%	2.0%	1.7%
Central Vermont Public Service Corp	3.9%	3.2%	1.5%	0.0%	3.0%	2.3%	4.0%	4.5%	4.5%	4.3%
Consolidated Edison, Inc.	4.0%	2.9%	0.8%	2.6%	2.0%	2.5%	2.5%	2.5%	2.5%	2.5%
Energy East Corp.	2.9%	3.1%	3.8%	3.7%	3.0%	3.3%	2.0%	2.0%	2.5%	2.2%
Northeast Utilities	3.2%	3.7%	1.6%	1.5%	5.0%	3.0%	4.0%	4.0%	4.0%	4.0%
NSTAR	5.2%	5.2%	4.9%	4.7%	2.5%	4.5%	5.0%	5.5%	6.0%	5.5%
Pepco Holdings, Inc.	5.3%	2.0%	2.5%	2.4%	1.5%	2.7%	3.0%	4.0%	5.5%	4.2%
UIL Holdings	0.6%	0.0%	0.0%	0.0%	0.5%	0.2%	0.5%	1.0%	1.5%	1.0%
Average						**2.5%**				**3.2%**

Source: Value Line Investment Survey.

Exhibit___(DCP-1)
Schedule 7
Page 3 of 4

COMPARISON COMPANIES
PER SHARE GROWTH RATES

COMPANY	5-Year Historic Growth Rates				Est'd '04-'06 to '10-'12 Growth Rates			
	EPS	DPS	BVPS	Average	EPS	DPS	BVPS	Average
Comparison Group								
Ameren Corp.	0.5%	0.0%	5.0%	1.8%	1.0%	0.0%	3.0%	1.3%
American Electric Power Company	3.0%	-9.5%	-2.5%	-3.0%	7.0%	7.5%	5.5%	6.7%
Consolidated Edison, Inc.	-2.0%	1.0%	2.5%	0.5%	3.0%	1.0%	3.5%	2.5%
Edison International	0.0%	8.5%	14.0%	7.5%	6.5%	7.5%	8.5%	7.5%
Entergy Corp.	10.0%	7.5%	4.5%	7.3%	7.5%	7.5%	6.5%	7.2%
Exelon Corp.	11.5%	0.0%	4.0%	5.2%	9.5%	7.5%	10.0%	9.0%
Firstenergy Corp.	0.0%	2.5%	6.0%	2.8%	12.0%	5.5%	5.5%	7.7%
FPL Group, Inc.	3.5%	4.5%	6.0%	4.7%	8.5%	5.5%	8.5%	7.5%
PPL Corp	8.5%	8.5%	12.0%	9.7%	10.5%	13.0%	8.0%	10.5%
Progress Energy	4.5%	3.0%	6.5%	4.7%	-1.5%	2.0%	3.0%	1.2%
Public Service Enterprise Group, Inc.	2.0%	0.5%	3.5%	2.0%	6.5%	1.5%	7.0%	5.0%
Southern Company	11.5%	2.5%	13.0%	9.0%	7.0%	6.0%	6.0%	6.3%
Average				**4.3%**				**6.0%**
Moul Electric Group								
CH Energy Group, Inc.	-1.5%	0.0%	2.0%	0.2%	1.0%	0.5%	1.5%	1.0%
Central Vermont Public Service Corp	1.0%	0.5%	2.5%	1.3%	10.0%	0.0%	2.5%	4.2%
Consolidated Edison, Inc.	-2.0%	1.0%	2.5%	0.5%	3.0%	1.0%	3.5%	2.5%
Energy East Corp.	-2.5%	5.0%	6.0%	2.8%	3.0%	4.5%	2.5%	3.3%
Northeast Utilities	0.0%	30.5%	3.0%	11.2%	8.5%	6.5%	1.5%	5.5%
NSTAR	4.0%	1.0%	2.0%	2.3%	7.5%	8.0%	6.0%	7.2%
Pepco Holdings, Inc.	-1.0%	0.0%	0.5%	-0.2%	8.0%	3.0%	3.0%	4.7%
UIL Holdings	-9.0%	0.0%	2.0%	-2.3%	6.0%	0.0%	2.0%	2.7%
Average				**2.0%**				**3.9%**

Source: Value Line Investment Survey.

Exhibit___(DCP-1)
Schedule 7
Page 4 of 4

COMPARISON COMPANIES
DCF COST RATES

COMPANY	ADJUSTED YIELD	HISTORIC RETENTION GROWTH	PROSPECTIVE RETENTION GROWTH	HISTORIC PER SHARE GROWTH	PROSPECTIVE PER SHARE GROWTH	FIRST CALL EPS GROWTH	AVERAGE GROWTH	DCF RATES
Comparison Group								
Ameren Corp.	5.0%	1.1%	1.7%	1.8%	1.3%	5.0%	2.2%	7.1%
American Electric Power Company	3.3%	4.7%	5.3%		6.7%	6.0%	5.7%	8.9%
Consolidated Edison, Inc.	4.7%	2.5%	2.5%	0.5%	2.5%	3.5%	2.3%	7.0%
Edison International	2.3%	9.6%	7.2%	7.5%	7.5%	7.0%	7.7%	10.0%
Entergy Corp.	2.1%	6.3%	8.3%	7.3%	7.2%	8.0%	7.4%	9.5%
Exelon Corp.	2.6%	12.0%	13.5%	5.2%	9.0%	8.6%	9.6%	12.2%
Firstenergy Corp.	3.1%	4.2%	7.3%	2.8%	7.7%	8.5%	6.1%	9.2%
FPL Group, Inc.	0.0%	5.5%	6.8%	4.7%	7.5%	8.5%	6.6%	6.6%
PPL Corp	3.1%	10.3%	8.3%	9.7%	10.5%	12.5%	10.3%	13.3%
Progress Energy	4.9%	2.7%	1.5%	4.7%	1.2%	5.0%	3.0%	7.9%
Public Service Enterprise Group, Inc.	2.9%	5.8%	7.8%	2.0%	5.0%	6.0%	5.3%	8.2%
Southern Company	4.5%	5.2%	3.7%	9.0%	6.3%	5.0%	5.8%	10.3%
Average	3.2%	5.8%	6.2%	5.0%	6.0%	7.0%	6.0%	**9.2%**
Median								**9.1%**
Composite		9.0%	9.4%	8.2%	9.2%	**10.2%**	9.2%	
Moul Electric Group								
CH Energy Group, Inc.	4.5%	1.4%	1.7%	0.2%	1.0%		1.1%	5.6%
Central Vermont Public Service Corp	3.1%	2.3%	4.3%	1.3%	4.2%		3.0%	6.1%
Consolidated Edison, Inc.	4.7%	2.5%	2.5%	0.5%	2.5%	3.5%	2.3%	7.0%
Energy East Corp.	5.0%	3.3%	2.2%	2.8%	3.3%	4.0%	3.1%	8.1%
Northeast Utilities	2.5%	3.0%	4.0%	11.2%	5.5%	12.0%	7.1%	9.7%
NSTAR	3.8%	4.5%	5.5%	2.3%	7.2%	6.0%	5.1%	8.9%
Pepco Holdings, Inc.	3.8%	2.7%	4.2%		4.7%	10.0%	5.4%	9.2%
UIL Holdings	5.0%	0.2%	1.0%		2.7%	8.0%	3.0%	8.0%
Average	4.0%	2.5%	3.2%	3.1%	3.9%	7.3%	3.8%	**7.8%**
Median								**8.0%**
Composite		6.5%	7.2%	7.1%	7.9%	**11.3%**	7.8%	

Sources: Prior pages of this schedule.

Exhibit___(DCP-1)
Schedule 8

STANDARD & POOR'S 500 COMPOSITE
20-YEAR U.S. TREASURY BOND YIELDS
RISK PREMIUMS

Year	EPS	BVPS	ROE	20-YEAR T-BOND	RISK PREMIUM
1977		$79.07			
1978	$12.33	$85.35	15.00%	7.90%	7.10%
1979	$14.86	$94.27	16.55%	8.86%	7.69%
1980	$14.82	$102.48	15.06%	9.97%	5.09%
1981	$15.36	$109.43	14.50%	11.55%	2.95%
1982	$12.64	$112.46	11.39%	13.50%	-2.11%
1983	$14.03	$116.93	12.23%	10.38%	1.85%
1984	$16.64	$122.47	13.90%	11.74%	2.16%
1985	$14.61	$125.20	11.80%	11.25%	0.55%
1986	$14.48	$126.82	11.49%	8.98%	2.51%
1987	$17.50	$134.04	13.42%	7.92%	5.50%
1988	$23.75	$141.32	17.25%	8.97%	8.28%
1989	$22.87	$147.26	15.85%	8.81%	7.04%
1990	$21.73	$153.01	14.47%	8.19%	6.28%
1991	$16.29	$158.85	10.45%	8.22%	2.23%
1992	$19.09	$149.74	12.37%	7.26%	5.11%
1993	$21.89	$180.88	13.24%	7.17%	6.07%
1994	$30.60	$193.06	16.37%	6.59%	9.78%
1995	$33.96	$215.51	16.62%	7.60%	9.02%
1996	$38.73	$237.08	17.11%	6.18%	10.93%
1997	$39.72	$249.52	16.33%	6.64%	9.69%
1998	$37.71	$266.40	14.62%	5.83%	8.79%
1999	$48.17	$290.68	17.29%	5.57%	11.72%
2000	$50.00	$325.80	16.22%	6.50%	9.72%
2001	$24.69	$338.37	7.43%	5.53%	1.90%
2002	$27.59	$321.72	8.36%	5.59%	2.77%
2003	$48.73	$367.17	14.15%	4.80%	9.35%
2004	$58.55	$414.75	14.98%	5.02%	9.96%
2005	$69.93	$453.06	16.12%	4.69%	11.43%
Average			**14.09%**	**7.90%**	**6.19%**

Sources: Standard & Poor's Analysts' Handbook and Ibbotson Associates 2006 Yearbook.

Exhibit___(DCP-1)
Schedule 9

COMPARISON COMPANIES
CAPM COST RATES

COMPANY	RISK-FREE RATE	BETA	MARKET RETURN	CAPM RATES
Comparison Group				
Ameren Corp.	4.91%	0.75	5.90%	9.3%
American Electric Power Company	4.91%	1.36	5.90%	12.9%
Consolidated Edison, Inc.	4.91%	0.75	5.90%	9.3%
Edison International	4.91%	1.10	5.90%	11.4%
Entergy Corp.	4.91%	0.85	5.90%	9.9%
Exelon Corp.	4.91%	0.90	5.90%	10.2%
Firstenergy Corp.	4.91%	0.85	5.90%	9.9%
FPL Group, Inc.	4.91%	0.85	5.90%	9.9%
PPL Corp	4.91%	0.95	5.90%	10.5%
Progress Energy	4.91%	0.90	5.90%	10.2%
Public Service Enterprise Group, Inc.	4.91%	1.00	5.90%	10.8%
Southern Company	4.91%	0.70	5.90%	9.0%
Average				**10.3%**
Median				**10.1%**
Moul Electric Group				
CH Energy Group, Inc.	4.91%	0.85	5.90%	9.9%
Central Vermont Public Service Corp	4.91%	0.70	5.90%	9.0%
Consolidated Edison, Inc.	4.91%	0.75	5.90%	9.3%
Energy East Corp.	4.91%	0.95	5.90%	10.5%
Northeast Utilities	4.91%	0.90	5.90%	10.2%
NSTAR	4.91%	0.80	5.90%	9.6%
Pepco Holdings, Inc.	4.91%	0.90	5.90%	10.2%
UIL Holdings	4.91%	0.95	5.90%	10.5%
Average				**9.9%**
Median				**10.1%**

Sources: Value Line Investment Survey, Standard & Poor's Analysts' Handbook, Federal Reserve.

Exhibit___(DCP-1)
Schedule 10
Page 1 of 2

COMPARISON COMPANIES
RATES OF RETURN ON AVERAGE COMMON EQUITY

COMPANY	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	1992-2001 Average	2002-2006 Average	2007	2008	2010-12
Comparison Group																				
Ameren Corp.	12.7%	12.9%	13.7%	13.1%	12.5%	10.8%	12.7%	12.5%	14.5%	14.3%	10.8%	12.2%	10.0%	10.3%	9.8%	13.0%	10.6%	9.0%	9.5%	9.0%
American Electric Power Company	*11.1%*	*11.9%*	*12.0%*	*12.4%*	*13.2%*	*13.5%*	*11.3%*	*10.5%*	*4.1%*	*12.9%*	12.3%	12.4%	12.7%	11.9%	10.4%	11.3%	11.9%	11.5%	11.5%	12.5%
Consolidated Edison, Inc.	12.0%	12.5%	13.5%	12.7%	12.2%	11.9%	11.9%	12.2%	10.7%	12.2%	11.5%	10.0%	8.0%	10.2%	14.3%	12.2%	10.8%	9.5%	9.5%	9.0%
Edison International	13.4%	11.8%	11.5%	11.8%	11.2%	11.8%	12.7%	13.7%	-52.0%	14.9%	15.4%	15.8%	3.9%	17.4%	20.2%	6.1%	14.5%	12.0%	5.0%	12.0%
Entergy Corp.	9.9%	9.9%	5.6%	7.6%	8.7%	8.1%	7.9%	7.8%	9.8%	9.4%	10.7%	10.1%	10.3%	11.9%	16.8%	8.5%	11.9%	14.5%	14.0%	13.0%
Exelon Corp.								34.9%	24.6%	18.2%	19.4%	19.7%	20.3%	22.9%	13.1%		19.1%	25.0%	24.5%	19.0%
Firstenergy Corp.	10.9%	11.9%	13.2%	13.2%	13.0%	11.3%	10.6%	13.0%	13.3%	12.5%	10.4%	6.0%	10.8%	10.5%	17.8%	12.3%	11.1%	14.5%	14.5%	13.5%
FPL Group, Inc.	13.1%	13.0%	13.2%	13.7%	13.7%	13.8%	14.0%	14.0%	13.4%	14.0%	11.6%	13.5%	12.6%	11.5%	12.2%	13.6%	12.3%	13.0%	13.0%	12.0%
PPL Corp	13.1%	13.2%	10.6%	12.1%	12.4%	11.7%	15.8%	17.9%	26.1%	27.0%	23.6%	23.1%	18.3%	16.8%	13.9%	16.0%	20.1%	16.5%	15.5%	21.5%
Progress Energy	15.4%	13.9%	12.3%	14.8%	15.3%	14.6%	14.4%	12.5%	9.8%	12.8%	13.7%	11.6%	10.1%	9.4%	11.4%	13.6%	11.2%	8.5%	8.5%	9.0%
Public Service Enterprise Group, Inc.	9.5%	13.1%	13.0%	12.3%	11.0%	10.8%	12.6%	15.4%	18.8%	18.8%	19.9%	18.2%	12.8%	14.9%	12.9%	13.5%	15.7%	16.5%	16.0%	13.5%
Southern Company	13.4%	13.4%	12.4%	13.0%	12.6%	11.4%	12.3%	13.1%	13.6%	11.9%	15.7%	15.6%	15.2%	15.0%	14.2%	12.7%	15.1%	13.5%	13.0%	13.0%
Average	12.2%	12.5%	11.9%	12.4%	12.4%	11.8%	12.4%	14.8%	8.9%	14.9%	14.6%	14.0%	12.1%	13.6%	13.9%	**12.1%**	**13.7%**	**13.7%**	**12.9%**	**13.1%**
Composite																**12.4%**	**13.6%**			
Moul Electric Group																				
CH Energy Group, Inc.	11.0%	11.1%	10.7%	10.7%	11.3%	10.9%	10.4%	10.2%	10.5%	10.4%	7.0%	9.1%	8.7%	8.9%	8.3%	10.7%	8.4%	8.0%	8.0%	8.5%
Central Vermont Public Service Corp	12.1%	11.2%	8.7%	9.8%	8.9%	8.1%	1.1%	8.1%	7.0%	5.7%	9.4%	8.2%	8.0%	5.7%	13.7%	8.1%	9.0%	9.0%	9.5%	8.5%
Consolidated Edison, Inc.	12.0%	12.5%	13.5%	12.7%	12.2%	11.9%	11.9%	12.2%	10.7%	12.2%	11.5%	10.0%	8.0%	10.2%	14.3%	12.2%	10.8%	9.5%	9.5%	9.0%
Energy East Corp.	10.7%	9.1%	10.3%	10.5%	10.1%	9.9%	11.2%	14.4%	15.1%	13.4%	9.3%	8.3%	9.1%	9.3%	18.5%	11.5%	10.9%	8.0%	8.5%	9.5%
Northeast Utilities	12.6%	9.4%	12.6%	11.9%	0.1%	-6.2%	-2.3%	-7.3%	-1.3%	8.6%	6.4%	7.1%	5.1%	5.4%	9.9%	3.8%	6.8%	8.5%	8.5%	8.5%
NSTAR	11.4%	11.9%	12.2%	10.2%	12.6%	12.6%	12.5%	11.4%	12.3%	13.4%	14.0%	13.9%	13.4%	13.1%	10.5%	12.1%	13.0%	13.5%	14.0%	15.0%
Pepco Holdings, Inc.	10.6%	12.0%	10.8%	10.5%	11.7%	10.5%	11.3%	11.7%	8.9%	11.9%	9.8%	7.6%	8.3%	8.1%	14.4%	11.0%	9.6%	8.5%	9.5%	11.0%
UIL Holdings	10.8%	10.4%	10.9%	11.8%	10.1%	10.4%	9.5%	11.5%	12.8%	12.1%	8.9%	6.1%	7.5%	5.2%	11.2%	11.0%	7.8%	8.0%	8.5%	8.0%
Average	*11.4%*	*11.0%*	*11.2%*	*11.0%*	*9.6%*	*8.5%*	8.2%	*9.0%*	9.5%	*11.0%*	9.5%	8.8%	8.5%	8.2%	12.6%	**10.0%**	**9.5%**	**9.1%**	**9.5%**	**9.8%**
Composite																**10.0%**	**9.5%**			

Source: Calculations made from data contained in Value Line Investment Survey.

Exhibit___(DCP-1)
Schedule 10
Page 2 of 2

COMPARISON COMPANIES
MARKET TO BOOK RATIOS

COMPANY	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	1992-2001 Average	2002-2006 Average
Comparison Group																	
Ameren Corp.	168.9%	187.9%	160.4%	170.5%	175.0%	173.8%	180.5%	167.2%	162.6%	173.5%	162.6%	162.4%	161.2%	171.5%	190.3%	172%	170%
American Electric Power Company	142.7%	158.9%	142.7%	156.0%	175.9%	186.8%	191.3%	154.4%	147.2%	179.0%	137.7%	123.8%	155.2%	164.6%	136.8%	164%	144%
Consolidated Edison, Inc.	141.0%	160.2%	125.2%	125.3%	126.8%	138.2%	186.4%	170.0%	128.5%	142.4%	143.6%	146.1%	142.9%	153.5%	219.5%	144%	161%
Edison International	167.5%	171.7%	122.1%	115.8%	120.4%	158.5%	191.7%	173.2%	196.5%	128.2%	116.7%	108.5%	153.0%	204.8%	262.6%	155%	169%
Entergy Corp.	124.5%	137.2%	104.4%	87.5%	97.2%	94.5%	99.4%	99.3%	98.5%	117.7%	114.3%	135.8%	156.4%	194.3%	279.7%	106%	176%
Exelon Corp.									119.5%	225.9%	191.2%	226.9%	280.4%	353.6%	214.6%		253%
Firstenergy Corp.	136.6%	153.9%	131.5%	136.6%	137.3%	140.1%	166.1%	144.0%	124.2%	136.2%	131.0%	131.9%	153.6%	169.0%	254.7%	141%	168%
FPL Group, Inc.	173.3%	180.0%	151.1%	174.6%	183.6%	198.2%	233.8%	176.6%	176.7%	186.0%	159.6%	167.1%	174.4%	197.6%	176.1%	183%	175%
PPL Corp	170.5%	181.5%	144.4%	138.4%	143.5%	127.9%	176.1%	231.9%	257.4%	351.9%	253.1%	239.0%	230.4%	259.3%	198.0%	192%	249%
Progress Energy	171.3%	191.6%	159.5%	181.4%	209.2%	207.4%	232.9%	188.9%	162.9%	163.8%	152.2%	144.8%	143.9%	137.3%	197.8%	187%	155%
Public Service Enterprise Group, Inc.	137.7%	159.7%	130.9%	128.8%	128.3%	122.1%	164.5%	184.5%	201.0%	225.1%	178.0%	186.1%	190.9%	245.0%	228.3%	158%	206%
Southern Company	154.4%	180.0%	161.3%	173.8%	176.0%	166.8%	197.5%	185.7%	187.9%	208.9%	230.4%	233.4%	226.7%	238.3%	230.2%	179%	232%
Average	153%	169%	139%	144%	152%	156%	184%	171%	164%	187%	164%	167%	181%	207%	216%	**162%**	**188%**
Composite																**162%**	**187%**
Moul Electric Group																	
CH Energy Group, Inc.	123.2%	133.1%	106.6%	111.7%	114.1%	135.3%	154.6%	132.9%	124.6%	141.0%	152.2%	147.1%	149.3%	145.9%	152.6%	128%	149%
Central Vermont Public Service Corp	157.6%	156.3%	115.2%	92.1%	85.5%	79.2%	78.1%	75.8%	69.9%	96.4%	108.5%	118.9%	133.8%	131.2%	265.3%	101%	152%
Consolidated Edison, Inc.	141.0%	160.2%	125.2%	125.3%	126.8%	138.2%	186.4%	170.0%	128.5%	142.4%	143.6%	146.1%	142.9%	153.5%	219.5%	144%	161%
Energy East Corp.	131.1%	143.0%	104.9%	96.1%	94.0%	108.2%	168.7%	186.0%	151.3%	131.0%	120.7%	118.9%	137.8%	140.9%	252.8%	131%	154%
Northeast Utilities	154.2%	149.4%	127.0%	123.5%	94.5%	64.3%	90.7%	113.3%	136.4%	129.0%	99.4%	95.3%	105.5%	108.4%	152.6%	118%	112%
NSTAR	138.4%	153.9%	130.0%	129.6%	124.7%	146.4%	180.8%	165.8%	160.8%	161.3%	170.2%	174.6%	189.3%	202.2%	169.1%	149%	181%
Pepco Holdings, Inc.	159.6%	162.2%	135.5%	138.3%	160.7%	151.0%	161.3%	166.1%	138.8%	124.4%	109.9%	102.9%	109.2%	121.9%	260.3%	150%	141%
UIL Holdings	129.1%	140.2%	113.8%	110.4%	113.9%	111.2%	151.5%	143.8%	140.9%	139.4%	125.8%	112.7%	141.6%	122.6%	214.1%	129%	143%
Average	142%	150%	120%	116%	114%	117%	147%	144%	131%	133%	129%	127%	139%	141%	211%	**131%**	**149%**
Composite																**131%**	**149%**

Source: Calculations made from data contained in Value Line Investment Survey.

Exhibit___(DCP-1)
Schedule 11

STANDARD & POOR'S 500 COMPOSITE RETURNS AND MARKET-TO-BOOK RATIOS
1992 - 2005

YEAR	RETURN ON AVERAGE EQUITY	MARKET-TO BOOK RATIO
1992	12.2%	271%
1993	13.2%	272%
1994	16.4%	246%
1995	16.6%	264%
1996	17.1%	299%
1997	16.3%	354%
1998	14.6%	421%
1999	17.3%	481%
2000	16.2%	453%
2001	7.5%	353%
2002	8.4%	296%
2003	14.2%	278%
2004	15.0%	291%
2005	16.1%	278%
Averages:		
1992-2001	14.7%	341%
2001-2005	12.2%	299%

Source: Standard & Poor's Analyst's Handbook, 2005 edition, page 1.

Exhibit___(DCP-1)
Schedule 12

RISK INDICATORS

GROUP	VALUE LINE SAFETY	VALUE LINE BETA	VALUE LINE FIN STR	S & P STK RANK
S & P's 500 Composite	2.7	1.05	B++	B+
Comparison Group	1.9	0.91	A	B+
Moul Electric Group	2.1	0.85	B++	B+

Sources: Value Line Investment Survey, Standard & Poor's Stock Guide.

Definitions:

Safety rankings are in a range of 1 to 5, with 1 representing the highest safety or lowest risk.

Beta reflects the variability of a particular stock, relative to the market as a whole. A stock with a beta of 1.0 moves in concert with the market, a stock with a beta below 1.0 is less variable than the market, and a stock with a beta above 1.0 is more variable than the market.

Financial strengths range from C to A++, with the latter representing the highest level.

Common stock rankings range from D to A+, with the latter representing the highest level.

Exhibit___(DCP-1)
Schedule 13

PPL ELECTRIC
TOTAL COST OF CAPITAL

ITEM	PERCENT	COST RATE	WEIGHTED COST
Long-Term Debt	46.41%	5.93%	2.7521%
Preferred Stock	10.46%	6.24%	0.6527%
Common Equity	43.13%	9.63%	4.1513%
Total	100.00%		**7.5561%**

Exhibit___(DCP-1)
Schedule 14

PPL ELECTRIC
PRE-TAX COVERAGE

ITEM	PERCENT	COST RATE	WEIGHTED COST	PRE-TAX COST	
Long-Term Debt	46.41%	5.93%	2.75%	2.75%	
Preferred Stock	10.46%	6.24%	0.65%	1.12%	
Common Equity	43.13%	9.63%	4.15%	7.10%	(1)
TOTAL CAPITAL	53.59%		7.56%	10.96%	

(1) Post-tax weighted cost divided by .585065 (composite tax factor)

Pre-tax coverage = 10.96%/2.75%
3.98 X

Standard & Poor's Utility Benchmark Ratios:

	A
Pre-tax coverage (X) Business Position:	
3	2.8-3.4x
Total Debt to Total Capital (%) Business Position	
3	50 - 55%

Exhibit___(DCP-1)
Schedule 15
Page 1 of 2

ANNUAL RISK PREMIUMS IN MR. MOUL'S RISK PREMIUM ANALYSIS

Year	S&P Utility Index	Public Utility Bonds	Differential	Averages By Decade
1928	57.47%	3.08%	54.39%	
1929	11.02%	2.34%	8.68%	
1930	-21.96%	4.74%	-26.70%	
1931	-35.90%	-11.11%	-24.79%	
1932	-0.54%	7.25%	-7.79%	
1933	-21.87%	-3.82%	-18.05%	
1934	-20.41%	22.61%	-43.02%	
1935	76.63%	16.03%	60.60%	
1936	20.69%	8.30%	12.39%	
1937	-37.04%	-4.05%	-32.99%	
1938	22.45%	8.11%	14.34%	
1939	11.26%	6.76%	4.50%	-6.15%
1940	-17.15%	4.45%	-21.60%	
1941	-31.57%	2.15%	-33.72%	
1942	15.39%	3.81%	11.58%	
1943	46.07%	7.04%	39.03%	
1944	18.03%	3.29%	14.74%	
1945	53.33%	5.92%	47.41%	
1946	1.26%	2.98%	-1.72%	
1947	-13.16%	-2.19%	-10.97%	
1948	4.01%	2.65%	1.36%	
1949	31.39%	7.16%	24.23%	7.03%
1950	3.25%	2.01%	1.24%	
1951	18.63%	-2.77%	21.40%	
1952	19.25%	2.99%	16.26%	
1953	7.85%	2.08%	5.77%	
1954	24.72%	7.57%	17.15%	
1955	11.26%	0.12%	11.14%	
1956	5.06%	-6.25%	11.31%	
1957	6.36%	3.58%	2.78%	
1958	40.70%	0.18%	40.52%	
1959	7.49%	-2.29%	9.78%	13.74%
1960	20.26%	9.01%	11.25%	
1961	29.33%	4.65%	24.68%	
1962	-2.44%	6.55%	-8.99%	
1963	12.36%	3.44%	8.92%	
1964	15.91%	4.94%	10.97%	
1965	4.67%	0.50%	4.17%	
1966	-4.48%	-3.45%	-1.03%	
1967	-0.63%	-3.63%	3.00%	
1968	10.32%	1.87%	8.45%	
1969	-15.42%	-6.66%	-8.76%	5.27%

Source: Data contained in Exhibit No. PRM-1, Schedule 12, Page 1 of 2.

Exhibit___(DCP-1)
Schedule 15
Page 2 of 2

ANNUAL RISK PREMIUMS IN MR. MOUL'S RISK PREMIUM ANALYSIS

Year	S&P Utility Index	Public Utility Bonds	Differential	Averages By Decade
1970	16.56%	15.90%	0.66%	
1971	2.41%	11.59%	-9.18%	
1972	8.15%	7.19%	0.96%	
1973	-18.07%	2.42%	-20.49%	
1974	-21.55%	-5.28%	-16.27%	
1975	44.49%	15.50%	28.99%	
1976	31.81%	19.04%	12.77%	
1977	8.64%	5.22%	3.42%	
1978	-3.71%	-0.98%	-2.73%	
1979	13.58%	-2.75%	16.33%	1.45%
1980	15.08%	-0.23%	15.31%	
1981	11.74%	4.27%	7.47%	
1982	26.52%	33.52%	-7.00%	
1983	20.01%	10.33%	9.68%	
1984	26.04%	14.82%	11.22%	
1985	33.05%	26.48%	6.57%	
1986	28.53%	18.16%	10.37%	
1987	-2.92%	3.02%	-5.94%	
1988	18.27%	10.19%	8.08%	
1989	47.80%	15.61%	32.19%	8.80%
1990	-2.57%	8.13%	-10.70%	
1991	14.61%	19.25%	-4.64%	
1992	8.10%	8.65%	-0.55%	
1993	14.41%	10.59%	3.82%	
1994	-7.94%	-4.72%	-3.22%	
1995	42.15%	22.81%	19.34%	
1996	3.14%	3.04%	0.10%	
1997	24.69%	11.39%	13.30%	
1998	14.82%	9.44%	5.38%	
1999	-8.85%	-1.69%	-7.16%	1.57%
2000	59.70%	9.45%	50.25%	
2001	-30.41%	5.85%	-36.26%	
2002	-30.04%	1.63%	-31.67%	
2003	26.11%	10.01%	16.10%	
2004	24.22%	6.03%	18.19%	
2005	16.79%	3.02%	13.77%	
2006	20.95%	3.94%	17.01%	6.77%
Averages	11.14%	5.73%	5.41%	
Standard Deviation	22.55%	7.89%	19.84%	

Source: Data contained in Exhibit No. PRM-1, Schedule 12, Page 1 of 2.

OCA St. No. 2S

AUG 1 3 2007
Hbg DC

BEFORE THE PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA PUBLIC UTILITY COMMISSION

V.

PPL ELECTRIC UTILITIES CORPORATION

DOCKET NO. R-00072155

DOCUMENT
FOLDER

SURREBUTTAL TESTIMONY OF

DAVID C. PARCELL

RECEIVED
AUG 1 4 2007
PA PUBLIC UTILITY COMMISSION
SECRETARY'S BUREAU

TOPIC ADDRESSED:
FAIR RATE OF RETURN

ON BEHALF OF
OFFICE OF CONSUMER ADVOCATE

AUGUST 2007

APPLICATION OF
PPL ELECTRIC UTILITIES CORPORATION
DOCKET NO. R-00072155

SURREBUTTAL TESTIMONY
OF
DAVID C. PARCELL

INTRODUCTION

Q. PLEASE STATE YOUR NAME, OCCUPATION, AND BUSINESS ADDRESS.

A. My name is David C. Parcell. I am President and Senior Economist of Technical Associates, Inc. My business address is Suite 601, 1051 East Cary Street, Richmond, VA 23219.

Q. ARE YOU THE SAME DAVID C. PARCELL WHO FILED DIRECT TESTIMONY IN THIS PROCEEDING IDENTIFIED AS OCA ST. NO. 2?

A. Yes, I am.

Q. WHAT IS THE PURPOSE OF YOUR PRESENT TESTIMONY?

A. My present testimony is prepared to respond to the rebuttal testimonies of PPL Electric witnesses Paul L. Moul and Julie M. Cannell. I also provide limited updates and revisions to my direct testimony.

RESPONSE TO REBUTTAL TESTIMONY OF PAUL R. MOUL

Q. HOW IS YOUR SURREBUTTAL TESTIMONY TO PAUL R. MOUL ORGANIZED?

A. My surrebuttal testimony takes the same format as the rebuttal testimony of Mr. Moul:

Appropriateness of PPL Electric's requested return
Discounted Cash Flow Methodology
Risk Premium Methodology
Capital Asset Pricing Model Methodology
Comparable Earnings Methodology

Appropriateness Of PPL Electric's Requested Return

Q. WHAT IS MR. MOUL'S CLAIM AS TO THE APPROPRIATENESS OF PPL ELECTRIC'S REQUESTED RETURN ON EQUITY VERSUS YOUR RECOMMENDATION?

A. Mr. Moul claims, on pages 3-4, that PPL Electric is more risky than was the case in 2004 at the time of its last rate case, with the implication that its cost of capital has increased. His only justification for this statement is a reference to PPL Electric's financial risk being different because its common equity ratio is lower now than at the time of the last case.

In making this claim, Mr. Moul is ignoring the fact that the cost of equity has declined since 2004. As evidence of this, consider the findings of Regulatory Focus (published by Regulatory Research Associates) that reflect the following average authorized returns on equity for electric utilities in the U.S.

Year	Avg. ROE
2004	10.75%
2005	10.54%
2006	10.36%
2007	10.27% (6 months)

This makes it clear that the average cost of equity for electric utilities, as authorized by regulatory commissions in the U.S., has declined by nearly 50 basis points since 2004. This is contrary to Mr. Moul's position (page 3, lines 8-9) that "the cost of equity cannot be less than 10.7% adopted by Commission for PPL Electric in its 2004 rate case."

In addition, Mr. Moul is ignoring the fact that PPL Electric's ratings (by Moody's) are higher presently (Baa 1 Insurer Rating and A3 First Mortgage Bonds) than was the case in 2004 (Baa2 and Baa1 respectively). This is indicative of lower risk faced by the Company.

Q. ARE THERE ANY REASONS TO BELIEVE THAT THE COST OF EQUITY FOR PPL ELECTRIC IS LESS THAN THAT FOR ELECTRIC UTILITIES IN GENERAL?

A. Yes, there are several factors that indicate that PPL Electric is less risky than electric utilities in general. First, as acknowledged on pages 1-2 by Mr. Moul (thought he did not recognize this in his risk assessment), PPL Electric is proposing a "future test period" and is, in its rebuttal filing, revising its projected cost of debt upward. Most electric utilities do not have the benefit of future test periods.

Second, PPL Electric's bonds are rated single-A by both Moody's and S&P. The majority of electric utilities are rated triple-B. For example, of the 66 electric and combination electric utilities followed by AUS Utility Reports, only 17 have S&P ratings of single-A or above and only 15 have Moody's ratings of single-A or above.

Q. MR. MOUL ALSO CLAIMS, ON PAGE 6, THAT INTEREST RATES HAVE INCREASED IN RECENT MONTHS. DO YOU HAVE ANY COMMENTS ON THIS CLAIM?

A. Yes, I do. Mr. Moul had taken a short-term view of interest rates and only considers changes "during the last several months." What Mr. Moul does not note is that single-A rated utility bonds, which are presently yielding about 6 percent, in 2004 (at the time of PPL Electric's last rate case) were yielding over 6 percent. In fact, single-A yields were over 6 percent during the middle of 2006, just a year ago. Thus, yields vary over short-term periods and Mr. Moul's observations only focus on short-term trends. On a longer-term basis, single-A utility debt remains low by historic standards and lower than at the time of PPL Electric's last rate case.

Q. MR. MOUL ALSO CLAIMS, ON PAGES 6-7, THAT PPL ELECTRIC'S "EXEMPLARY PERFORMANCE" DESERVES AN ABOVE-AVERAGE COST OF EQUITY. WHAT IS YOUR RESPONSE TO THIS?

A. As I indicated in my direct testimony, ratepayers have a right to expect "competent and economical management" in the operation of a regulated utility. There should not be any reward for management doing the job for which they are paid.

Discounted Cash Flow Methodology

Q. WHAT ARE THE PRIMARY FACTORS CITED BY MR. MOUL IN HIS DCF REBUTTAL TESTIMONY?

A. Mr. Moul's primary claims in this section of his rebuttal testimony are:

Selection of proxy groups,
Proper growth rate in DCF, and
Adjustment to DCF cost rates.

Q. MR. MOUL CLAIMS, ON PAGES 11-12, THAT YOU HAVE USED A "MORE DIVERSE GROUP OF COMPANIES" IN YOUR PROXY GROUP THAN IS THE CASE FOR HIS PROXY GROUP. WHAT IS YOUR RESPONSE TO THIS CLAIM?

A. I note, first of all, that all of my cost of capital analyses (i.e., DCF, CAPM and CE) apply the financial models not only to my proxy group but to Mr. Moul's proxy group. As a result, his statement is misleading since the selection of proxy groups does not govern the differences between our recommendations. I also note that my DCF, CAPM and CE model results are all higher for my proxy group than is the case for Mr. Moul's proxy group. As a result, I am recommending a higher cost of equity for PPL Electric than would be the case had I restricted my analyses to his proxy group.

Aside from this, I disagree with Mr. Moul's implication that my proxy group is not representative of PPL Electric. Schedule 6 of OCA St. No. 2 indicates that the members of my proxy group are similar to PPL in terms of size, operations, capital structures, and risk factors. These are the appropriate standards for selecting a proxy group.

Q. ON PAGES 12-13, MR. MOUL REFERS TO YOUR "DCF RESULTS" AND CITES THE RESULTS OF INDIVIDUAL COMPANIES. IS THIS AN ACCURATE PORTRAYAL OF YOUR DCF ANALYSIS?

A. No, it is not. Mr. Moul has made 2 significant mischaracterization and misinterpretation of my DCF analysis. Since I have shown the mathematical combination of dividend yields and various growth rates, he apparently has misinterpreted these combinations to be "DCF results."

I think my testimony is clear that investors consider various alternative growth rates in making investment decisions. As such, investors evaluate these alternative growth rates to assist them in their investment decisions. However, it does not follow that each individual growth rate reflects an "investor decision" and thus each growth rate creates a DCF estimated common equity cost rate. Rather, it is the cumulative impact of all these growth rates, or some combination of growth rates that form the basis of investor decisions and thus, DCF estimated common equity cost rates.

It is likely that the primary reason for Mr. Moul's misinterpretation of my DCF analysis is the difference in the manner in which he and I calculated our DCF costs. He looks at alternative growth rates and reaches a single growth rate conclusion to be combined with a single dividend yield to reach a DCF estimate of the cost of equity, whereas I combine the various growth rates directly with the dividend yields. We both reach conclusions based on our own interpretation of the proper growth rates. The fact that I show individual combinations of yields and growth rates, which are then used as inputs into my ultimate estimate of the DCF costs of equity, appears to have confused him and apparently results in his misinterpretation of my analyses.

This misinterpretation obscures the real difference in our respective DCF analyses, notably whether primary reliance on analysts' forecasts of EPS growth, is proper in a DCF analysis.

Q. MR. MOUL CLAIMS, ON PAGE 14, THAT EPS PROJECTIONS ARE THE 'BEST MEASURE OF GROWTH IN THE DCF MODEL." WHAT IS YOUR RESPONSE TO THIS ASSERTION?

A. Mr. Moul has answered the wrong question. He should have asked and answered the question of whether EPS projections are the "only" measure of growth considered by investors. The answer to this question is clearly "no".

Q. WHY IS IT IMPROPER TO EXCLUSIVELY RELY ON EPS PROJECTIONS IN A DCF ANALYSIS?

A. There have been several events in recent years that should have given investors reason to question the accuracy of EPS projections, and therefore the relative weight of such forecasts in establishing stock prices.

First, recent academic scholarship has challenged the accuracy of analysts' EPS forecasts. A prominent example is a 1998 article (in the Financial Analysts Journal, Vol. 54, No. 6, Nov./Dec. 1998, 35-42) titled "Why So Much Error In Analysts' Earnings Forecasts?", by Vijay Kumer Chopra. In this article, the author concluded "Analysts' forecasts of EPS and growth in EPS tend to be overly optimistic." He concluded that analysts' forecasts of EPS over the past 13 years have been more than twice the actual growth rate.

Another source is less academic and more directly related to the financial mainstream. On March 26, 2002, then-Federal Reserve Chairman Alan Greenspan spoke to an audience at the Stern School of Business of New York University. In that speech, (available at the FRB's website: http://www.federalreserve.gov), the Chairman addressed the historical relationships and roles of corporations, financial institutions and brokerage-based investment analysts:

> "For the most part, despite providing limited incentives for board members to safeguard shareholder interest, this paradigm has worked well. We are fortunate for financial markets have had no realistic alternative other than to depend on the chief executive officer to ensure an objective evaluation of the prospects of the corporation. Apart from a relatively few large institutional investors, not many existing or potential shareholders have the research capability to analyze corporate reports and thus judge the investment value of a corporation. This vitally important service has become dominated by firms in the business of underwriting or selling securities."
>
> "But, as we can see from recent history, long-term earnings forecasts of brokerage-based securities analysts, on average, had been persistently overly optimistic. Three to five-years earnings forecasts for each of the S&P 500 corporations, compiled from projections of securities analysts by I/B/E/S, averaged almost 12 percent per year between 1985 and 2001. Actual earnings growth over the period averaged about 9 percent."
>
> "Perhaps the last sixteen years for which systematic data have been available are a historic aberration. But the persistence of the bias year after year suggests that it more likely results, at least in part, from the proclivity of firms that sell securities to retain and promote analysts with

> an optimistic inclination. Moreover, the bias apparently has been especially large when the brokerage firm issuing the forecast also serves as an underwriter for the company's securities."

Still another source of new insight and perspective is, unfortunately, the well-publicized financial debacles of Enron and WorldCom. These sagas demonstrate dramatically how analysts are often either unwilling or incapable of discerning potentially disastrous impacts on a company's projected EPS, and how even current earnings can be distorted by the complex financial machinations of large, aggressive corporations.

Finally, during 2003, ten of the nation's largest securities firms agreed to pay a record $1.4 billion in penalties to settle U.S. government charges involving investor abuses, many of which resulted from analysts' forecasts and recommendations that the government charged were biased and subject to conflicts-of-interests. This settlement largely grew out of a New York State investigation and reflects the national, and even international, scope of the negative perceptions of analysts' forecasts and recommendations. These, and other, similar investigations and complaints have underscored a growing awareness that analysts' estimates cannot be considered an unbiased source of growth expectations by investors, and this understanding has important implications for a DCF analysis that exclusively incorporates any such estimates.

In summary, investors are now very much aware of recent scandals involving security analysts, including the Enron and WorldCom debacles, conflicts of interest that have resulted in settlements, fines, and public admonishments, as well as other negative connotations related to the reliability of analysts' forecasts. These problems clearly call into question the reliance on analysts' forecasts as the only source of growth in a DCF context. The landscape has changed in recent years and investors have ample reasons to doubt the exclusive reliability of such forecasts at the present time.

Q. IS IT POSSIBLE THAT RECENT STEPS BY THE SECURITIES AND EXCHANGE COMMISSION HAVE THE EFFECT OF REMOVING ANY PAST PERCEPTION OF ANALYSTS' FORECASTS?

A. No, I do not believe so. SEC measures may have the impact of correcting some past abuses by analysts and forecasters, but this does not mean that all investors will be convinced that the problem is solved. The extremely negative publicity associated with the Enron, WorldCom, and New York State investigations will have a lingering effect on investors, whose losses due to incorrect and/or improper forecasts have a much larger impact on their decision-making than a promise by the SEC that abuses have been eliminated. In any event, it remains an unlikely proposition to maintain that all investors rely exclusively on analysts' forecasts of EPS in making all investment decisions.

Q. MR. MOUL CRITICIZES YOUR USE OF THE RETENTION GROWTH RATE, ON PAGES 15-17. IS THIS CRITICISM JUSTIFIED?

A. No, it is not. The retention growth rate, which is one of several growth rates I utilize, has a long-standing history as an indicator of expected growth. In fact, Myron Gordon, the recognized originator of the DCF model as a method of estimating the cost of equity for utilities, identified retention growth as a primary source of growth in the DCF model. In addition, the Federal Energy Regulatory Commission uses retention growth as one of two growth rates it uses in setting rates for electric utilities at the interstate level.

Mr. Moul also criticizes my use of Value Line's retention growth rates, saying I should have calculated my own retention growth rates (Page 17). This criticism is also without merit. Use of Value Line retention growth rates reflects what investors have access to when they review Value Line in making investment decisions.

In addition, Mr. Moul's suggestion (Page 17) that it is necessary to "convert" Value Line's retention growth rates is incorrect. Subscribers to Value Line are not generally paying for this service as a data source for the purposes of "converting" the various ratios, but rather are using Value Line for the ratios and projections that it provides. It is neither likely nor realistic to expect Value Line subscribers to "convert" its ratios.

Q. MR. MOUL ALSO CRITICIZES YOUR GROWTH RATE AVERAGES AS BEING TOO LOW (PAGE 13). WHAT IS YOUR RESPONSE TO THIS?

A. I disagree with Mr. Moul. I have considered a number of growth rate indicators in my DCF analyses, as has Mr. Moul. The major differences in our analyses is that Mr. Moul essentially ignores most of the indicators he examines and only utilizes the few results that produce the highest DCF results. He thus assumes that investors only consider the most optimistic growth rates in making investment decisions. Such an investment strategy is likely to produce an over-optimistic and unrealistic view of stock performance.

Q. MR. MOUL MAINTAINS IN HIS REBUTTAL TESTIMONY (PAGES 17-19), AS HE DID IN HIS DIRECT TESTIMONY, THAT THE DCF MODEL CANNOT BE USED AS AN ESTIMATE OF THE COST OF EQUITY FOR A UTILITY WHEN THE MARKET PRICE OF UTILITY STOCKS EXCEEDS THE BOOK VALUE. DO YOU AGREE WITH THIS POSITION?

A. No, I do not. Knowledgeable and/or informed investors are aware of the fact that most utilities have their rates set based on the book value of their assets (i.e., rate base and capital structure). This knowledge is reflected in the prices that investors are willing to pay for stocks and thus is reflected in DCF cost rates. To make a modification of the DCF cost rates, as Mr. Moul proposes, amounts to an attempt to "reprice" stock values in order to develop a DCF cost rate more in line with what he thinks the results should be. This is clearly a violation of the principle of "efficient markets." If one believes that markets are efficient, there is no reason to modify either stock prices or market models based on stock prices.

Risk Premium Method

Q. WHAT ARE YOUR COMMENTS ON MR. MOUL'S REBUTTAL TESTIMONY CONCERNING THE RISK PREMIUM METHOD?

A. Mr. Moul first maintains (Pages 24-25) that since I have used historical data in my testimony, this justifies the risk premium method he uses in his testimony. His position is incorrect. My use of historical data – five-year growth rates in DCF, comparison of returns on equity vs. bond yields and holding period returns in CAPM, and return on equity/market-to-book ratios in CE – uses consistent data and provides relevant historic comparisons. Mr. Moul's risk premium method, in contrast, gives equal weight to occurrences in 1928 to those of 2006. Yet, he has offered no demonstration that investors give such long-term relationships the same weight as recent relationships.

Capital Asset Pricing Model

Q. MR. MOUL CLAIMS, ON PAGES 27 AND 28, THAT YOUR CAPM MODEL IS INCORRECT SINCE YOU GIVE CONSIDERATION TO GEOMETRIC AS WELL AS ARITHMETIC RETURNS. WHAT IS YOUR RESPONSE TO THIS?

A. What is important is not what Mr. Moul and I believe, but what investors rely upon in making investment decisions. It is apparent that investors have access to both types of returns when they make investment decisions.

In fact, it is noteworthy that when mutual fund investors regularly receive reports on their own funds, as well as prospective funds they are considering investing in, these reports show only geometric returns. Based on this, I find it difficult to accept Mr. Moul's position that only arithmetic returns are appropriate.

Q. DOES MR. MOUL USE VALUE LINE INFORMATION IN HIS COST OF CAPITAL ANALYSES?

A. Yes, he does.

Q. DO THE VALUE LINE REPORTS SHOW HISTORIC GROWTH RATES FOR UTILITIES?

A. Yes, they do.

Q. DO THESE VALUE LINE REPORTS SHOW HISTORIC RETURNS ON AN ARITHMETIC BASIS?

A. No, they do not.

Q. DO THE VALUE LINE REPORTS SHOW HISTORIC RETURNS ON A GEOMETRIC, OR COMPOUND GROWTH RATE BASIS?

A. Yes, they do.

Q. IS IT YOUR POSITION THAT ONLY GEOMETRIC GROWTH RATES BE USED?

A. No. I believe that both arithmetic are geometric growth rates should be used. This is the case since investors have access to both and presumably use both. This is also consistent with the efficient market hypothesis.

Q. BUT DOES NOT MR. MOUL CITE (PAGES 28-29) HIS PERCEPTION THAT FINANCIAL LITERATURE REQUIRES THAT ARITHMETIC RETURNS BEING USED EXCLUSIVELY?

A. He does state this in his testimony. However, the cost of capital determination is not an academic exercise made in some laboratory or university classroom. The true cost of equity is made in the "laboratory" of the financial markets, based on the ongoing interplay of countless investors, each with their own agendas and beliefs. This is verified by the fact that each time a share of stock is purchased by one investor, it is simultaneously being sold by another investor, indicating that their respective views at that time differ.

Again, investors have access to both arithmetic and geometric growth rates. In all likelihood, there is more geometric growth readily available to investors (e.g., mutual fund reports and Value Line) than arithmetic growth.

Q. MR. MOUL ALSO CONTINUES TO DEFEND HIS USE OF "LEVERAGED BETAS" IN HIS CAPM (PAGES 29-30). DOES HIS REBUTTAL TESTIMONY PROVIDE ANY FURTHER JUSTIFICATION FOR THIS ADJUSTMENT?

A. No, it does not. Betas are readily available to investors, as they can be easily found in publications such as Value Line. Suffice it to say that if Value Line and/or investors believed that these betas should be adjusted prior to their use in investment decisions, they would be calculated in this fashion. It is simply not realistic to believe that investors are going to make adjustments to betas, as Mr. Moul maintains, in making investment decisions. In addition, Mr. Moul's reference to market-to-book ratios is not relevant.

Any importance of market-to-book ratios is already reflected in market prices and thus betas.

Comparable Earnings

Q. MR. MOUL MAINTAINS (PAGES 31-32) THAT THE "UNDERLYING PREMISE OF THE COMPARABLE EARNINGS METHOD IS THAT REGULATION SHOULD EMULATE RESULTS OBTAINED BY FIRMS OPERATING IN COMPETITIVE MARKETS AND THAT A UTILITY MUST BE GIVEN AN OPPORTUNITY COST OF CAPITAL EQUAL TO THAT WHICH COULD BE EARNED IF ONE INVESTED IN FIRMS OF COMPARABLE RISK." DO YOU AGREE WITH THIS PREMISE?

A. I agree with this statement in principle, but I disagree with the interpretation made by Mr. Moul that utilities should be entitled to returns commensurate with those earned by competitive firms. An implicit assumption in Mr. Moul's interpretation of the comparable earnings analysis is that the earnings of unregulated firms equates to the costs of capital for these firms. Yet, Mr. Moul has made no analyses or other attempts to indicate that the achieved and/or expected returns of unregulated firms do not exceed their cost of capital.

It is evident, however, from my analyses that the earnings of Mr. Moul's unregulated firms exceed the required cost of capital for regulated utilities such as PPL Electric. This is the case since unregulated firms are not comparable to regulated utilities. This is evidenced by the fact that the earnings in Mr. Moul's proxy group have been much less than those for his unregulated group, yet have been able to maintain the same levels of "risk indicators" while earning lower earnings levels. This is evidence that the required cost of equity is less for electric utilities than for unregulated firms. It is noteworthy that Mr. Moul does not address this in his rebuttal testimony.

Q. MR. MOUL CLAIMS (PAGES 33-34) THAT "AN ANALYSIS OF M/B RATIOS ARE NOT NECESSARY TO APPLY THE COMPARABLE EARNINGS METHOD." DO YOU AGREE?

A. No, I do not. I believe it is inconsistent for Mr. Moul to maintain that his DCF and CAPM results should be modified (i.e., leverage adjustment) for M/B, but the comparable earnings analyses should not. It is appropriate for the comparable earnings analyses to be adjusted for M/B, since the comparable earnings method is based on book returns. The DCF and CAPM methodologies, in turn, are based on market returns, which already reflect any investor recognition of deviations of market prices from book values. As a result, it is improper for the DCF and CAPM to be adjusted for M/B, since any impact of M/B should already be reflected in the stock prices and thus DCF and CAPM results.

RESPONSE TO REBUTTAL TESTIMONY OF JULIE M. CANNELL

Q. WHAT IS THE PRIMARY POINT OF MS. CANNELL'S REBUTTAL TESTIMONY?

A. The primary point of her rebuttal testimony seems to be her perception that investors "expect" higher rates of return, nothwithstanding the results of recognized financial models and the downward trend in authorized returns by regulators. In fact, the words "expectations", "expecting", and "expect" appear in her rebuttal testimony a total of at least nine times in the four pages of her testimony wherein she discusses the return on equity area.

Q. DOES MS. CANNELL OFFER ANY PROOF OR VERIFICATION OF HER PERCEPTION OF INVESTORS' "EXPECTATIONS"?

A. No, she does not. It appears the entire context of her testimony is designed to deliver her perception of what investors "expect."

Q. CAN YOU OFFER ANY VERIFICATION OF INVESTOR EXPECTATIONS OF A DECLINING COST OF CAPITAL?

A. Yes, I can. The lead article of an issue of Business Week in February of this year was titled "It's a Low, Low, Low Low-Rate World – Why money may stay cheap longer than you think." In this Business Week article, which is a widely-read, popular-press publication, the authors concluded that current low rates (by historic standards) may remain this way for years to come.

A copy of this article is attached as Exhibit___(DCP-2), Schedule 1.

UPDATES AND REVISIONS TO DIRECT TESTIMONY

Q. DO YOU HAVE ANY UPDATES TO YOUR DIRECT TESTIMONY?

A. Yes, I do. In response to Mr. Moul's update of PPL Electric's cost of long-term debt (from 5.93 percent to 6.07 percent), I have updated my Exhibit ___(DCP-1), Schedule 13 to reflect this change. Schedule 13, updated, indicates that the total cost of capital I am proposing is now 7.6211 percent. The only change in this updated schedule is the cost of long-term debt.

Q. DO YOU HAVE ANY REVISIONS TO YOUR DIRECT TESTIMONY?

A. Yes, I do. Mr. Moul has correctly pointed out that my Exhibit ___(DCP-1), Schedule 7, Page 1, had an incorrect dividend rate for one company (FPL Corp.). As a result, I have revised Exhibit ___(DCP-1), Schedule 7, Pages 1 and 4, to reflect this correction.

I note, however, that this correction does not change my return on equity recommendation of 9.625 percent.

Q. DOES THIS CONCLUDE YOUR SURREBUTTAL TESTIMONY?

A. Yes, it does.

Updated and Corrected Schedules
Exhibit ___(DCP-1)
Schedules 7, 13, 14

Exhibit___(DCP-1)
Schedule 7
Page 1 of 4
Corrected

COMPARISON COMPANIES
DIVIDEND YIELD

COMPANY	DPS	March-May 2007 Stock Prices HIGH	LOW	AVERAGE	YIELD
Comparison Group					
Ameren Corp.	$2.54	$55.00	$48.56	$51.78	4.9%
American Electric Power Company	$1.56	$51.24	$44.03	$47.64	3.3%
Consolidated Edison, Inc.	$2.32	$52.90	$47.46	$50.18	4.6%
Edison International	$1.16	$60.26	$46.20	$53.23	2.2%
Entergy Corp.	$2.16	$120.47	$95.18	$107.83	2.0%
Exelon Corp.	$1.76	$79.38	$63.60	$71.49	2.5%
Firstenergy Corp.	$2.00	$72.90	$60.85	$66.88	3.0%
FPL Group, Inc.	$1.64	$66.52	$56.50	$61.51	2.7%
PPL Corp	$1.22	$49.44	$37.03	$43.24	2.8%
Progress Energy	$2.44	$52.75	$47.87	$50.31	4.8%
Public Service Enterprise Group, Inc.	$2.34	$93.80	$72.87	$83.34	2.8%
Southern Company	$1.61	$38.90	$34.85	$36.88	4.4%
Average					**3.3%**
Moul Electric Group					
CH Energy Group, Inc.	$2.16	$50.78	$45.05	$47.92	4.5%
Central Vermont Public Service Corp	$0.92	$37.07	$24.37	$30.72	3.0%
Consolidated Edison, Inc.	$2.32	$52.90	$47.46	$50.18	4.6%
Energy East Corp.	$1.20	$25.40	$23.50	$24.45	4.9%
Northeast Utilities	$0.75	$33.62	$28.20	$30.91	2.4%
NSTAR	$1.30	$37.37	$33.36	$35.37	3.7%
Pepco Holdings, Inc.	$1.04	$30.71	$25.85	$28.28	3.7%
UIL Holdings	$1.73	$37.01	$32.70	$34.86	5.0%
Average					**4.0%**

Source: Yahoo! Finance.

COMPARISON COMPANIES
RETENTION GROWTH RATES

COMPANY	2002	2003	2004	2005	2006	Average	2007	2008	2010-12	Average
Comparison Group										
Ameren Corp.	0.2%	2.2%	0.9%	1.7%	0.5%	1.1%	1.5%	1.5%	2.0%	1.7%
American Electric Power Company	2.4%	4.5%	5.7%	5.2%	5.7%	4.7%	5.5%	5.0%	5.5%	5.3%
Consolidated Edison, Inc.	4.0%	2.9%	0.8%	2.6%	2.0%	2.5%	2.5%	2.5%	2.5%	2.5%
Edison International	11.9%	13.6%	0.0%	12.3%	10.1%	9.6%	8.0%	7.5%	6.0%	7.2%
Entergy Corp.	7.1%	5.6%	5.8%	6.0%	7.0%	6.3%	9.5%	8.5%	7.0%	8.3%
Exelon Corp.	12.8%	11.5%	10.7%	11.9%	13.0%	12.0%	14.5%	14.5%	11.5%	13.5%
Firstenergy Corp.	4.3%	0.0%	4.9%	4.2%	7.5%	4.2%	7.5%	7.5%	7.0%	7.3%
FPL Group, Inc.	4.6%	6.4%	5.6%	4.0%	7.0%	5.5%	7.0%	7.0%	6.5%	6.8%
PPL Corp	12.4%	11.7%	9.3%	8.8%	9.5%	10.3%	8.0%	7.0%	10.0%	8.3%
Progress Energy	5.0%	3.7%	2.6%	1.7%	0.5%	2.7%	1.0%	1.5%	2.0%	1.5%
Public Service Enterprise Group, Inc.	8.3%	6.5%	3.5%	5.2%	5.5%	5.8%	8.5%	8.0%	7.0%	7.8%
Southern Company	4.7%	5.0%	5.9%	6.2%	4.0%	5.2%	4.0%	3.5%	3.5%	3.7%
Average						**5.8%**				**6.2%**
Moul Electric Group										
CH Energy Group, Inc.	0.0%	2.0%	1.7%	2.0%	1.5%	1.4%	1.5%	1.5%	2.0%	1.7%
Central Vermont Public Service Corp	3.9%	3.2%	1.5%	0.0%	3.0%	2.3%	4.0%	4.5%	4.5%	4.3%
Consolidated Edison, Inc.	4.0%	2.9%	0.8%	2.6%	2.0%	2.5%	2.5%	2.5%	2.5%	2.5%
Energy East Corp.	2.9%	3.1%	3.8%	3.7%	3.0%	3.3%	2.0%	2.0%	2.5%	2.2%
Northeast Utilities	3.2%	3.7%	1.6%	1.5%	5.0%	3.0%	4.0%	4.0%	4.0%	4.0%
NSTAR	5.2%	5.2%	4.9%	4.7%	2.5%	4.5%	5.0%	5.5%	6.0%	5.5%
Pepco Holdings, Inc.	5.3%	2.0%	2.5%	2.4%	1.5%	2.7%	3.0%	4.0%	5.5%	4.2%
UIL Holdings	0.6%	0.0%	0.0%	0.0%	0.5%	0.2%	0.5%	1.0%	1.5%	1.0%
Average						**2.5%**				**3.2%**

Source: Value Line Investment Survey.

Exhibit___(DCP-1)
Schedule 7
Page 3 of 4

COMPARISON COMPANIES
PER SHARE GROWTH RATES

	5-Year Historic Growth Rates				Est'd '04-'06 to '10-'12 Growth Rates			
COMPANY	EPS	DPS	BVPS	Average	EPS	DPS	BVPS	Average
Comparison Group								
Ameren Corp.	0.5%	0.0%	5.0%	1.8%	1.0%	0.0%	3.0%	1.3%
American Electric Power Company	3.0%	-9.5%	-2.5%	-3.0%	7.0%	7.5%	5.5%	6.7%
Consolidated Edison, Inc.	-2.0%	1.0%	2.5%	0.5%	3.0%	1.0%	3.5%	2.5%
Edison International	0.0%	8.5%	14.0%	7.5%	6.5%	7.5%	8.5%	7.5%
Entergy Corp.	10.0%	7.5%	4.5%	7.3%	7.5%	7.5%	6.5%	7.2%
Exelon Corp.	11.5%	0.0%	4.0%	5.2%	9.5%	7.5%	10.0%	9.0%
Firstenergy Corp.	0.0%	2.5%	6.0%	2.8%	12.0%	5.5%	5.5%	7.7%
FPL Group, Inc.	3.5%	4.5%	6.0%	4.7%	8.5%	5.5%	8.5%	7.5%
PPL Corp	8.5%	8.5%	12.0%	9.7%	10.5%	13.0%	8.0%	10.5%
Progress Energy	4.5%	3.0%	6.5%	4.7%	-1.5%	2.0%	3.0%	1.2%
Public Service Enterprise Group, Inc.	2.0%	0.5%	3.5%	2.0%	6.5%	1.5%	7.0%	5.0%
Southern Company	11.5%	2.5%	13.0%	9.0%	7.0%	6.0%	6.0%	6.3%
Average				**4.3%**				**6.0%**
Moul Electric Group								
CH Energy Group, Inc.	-1.5%	0.0%	2.0%	0.2%	1.0%	0.5%	1.5%	1.0%
Central Vermont Public Service Corp	1.0%	0.5%	2.5%	1.3%	10.0%	0.0%	2.5%	4.2%
Consolidated Edison, Inc.	-2.0%	1.0%	2.5%	0.5%	3.0%	1.0%	3.5%	2.5%
Energy East Corp.	-2.5%	5.0%	6.0%	2.8%	3.0%	4.5%	2.5%	3.3%
Northeast Utilities	0.0%	30.5%	3.0%	11.2%	8.5%	6.5%	1.5%	5.5%
NSTAR	4.0%	1.0%	2.0%	2.3%	7.5%	8.0%	6.0%	7.2%
Pepco Holdings, Inc.	-1.0%	0.0%	0.5%	-0.2%	8.0%	3.0%	3.0%	4.7%
UIL Holdings	-9.0%	0.0%	2.0%	-2.3%	6.0%	0.0%	2.0%	2.7%
Average				**2.0%**				**3.9%**

Source: Value Line Investment Survey.

Exhibit___(DCP-1)
Schedule 7
Page 4 of 4
Corrected

COMPARISON COMPANIES
DCF COST RATES

COMPANY	ADJUSTED YIELD	HISTORIC RETENTION GROWTH	PROSPECTIVE RETENTION GROWTH	HISTORIC PER SHARE GROWTH	PROSPECTIVE PER SHARE GROWTH	FIRST CALL EPS GROWTH	AVERAGE GROWTH	DCF RATES
Comparison Group								
Ameren Corp.	5.0%	1.1%	1.7%	1.8%	1.3%	5.0%	2.2%	7.1%
American Electric Power Company	3.4%	4.7%	5.3%		6.7%	6.0%	5.7%	9.0%
Consolidated Edison, Inc.	4.7%	2.5%	2.5%	0.5%	2.5%	3.5%	2.3%	7.0%
Edison International	2.3%	9.6%	7.2%	7.5%	7.5%	7.0%	7.7%	10.0%
Entergy Corp.	2.1%	6.3%	8.3%	7.3%	7.2%	8.0%	7.4%	9.5%
Exelon Corp.	2.6%	12.0%	13.5%	5.2%	9.0%	8.6%	9.6%	12.2%
Firstenergy Corp.	3.1%	4.2%	7.3%	2.8%	7.7%	8.5%	6.1%	9.2%
FPL Group, Inc.	2.8%	5.5%	6.8%	4.7%	7.5%	8.5%	6.6%	9.4%
PPL Corp	3.1%	10.3%	8.3%	9.7%	10.5%	12.5%	10.3%	13.3%
Progress Energy	4.9%	2.7%	1.5%	4.7%	1.2%	5.0%	3.0%	7.9%
Public Service Enterprise Group, Inc.	2.9%	5.8%	7.8%	2.0%	5.0%	6.0%	5.3%	8.2%
Southern Company	4.5%	5.2%	3.7%	9.0%	6.3%	5.0%	5.8%	10.3%
Average	3.4%	5.8%	6.2%	5.0%	6.0%	7.0%	6.0%	**9.4%**
Median								**9.3%**
Composite		9.2%	9.6%	8.4%	9.5%	**10.4%**	9.4%	
Moul Electric Group								
CH Energy Group, Inc.	4.5%	1.4%	1.7%	0.2%	1.0%		1.1%	5.6%
Central Vermont Public Service Corp	3.0%	2.3%	4.3%	1.3%	4.2%		3.0%	6.1%
Consolidated Edison, Inc.	4.7%	2.5%	2.5%	0.5%	2.5%	3.5%	2.3%	7.0%
Energy East Corp.	5.0%	3.3%	2.2%	2.8%	3.3%	4.0%	3.1%	8.1%
Northeast Utilities	2.5%	3.0%	4.0%	11.2%	5.5%	12.0%	7.1%	9.7%
NSTAR	3.8%	4.5%	5.5%	2.3%	7.2%	6.0%	5.1%	8.9%
Pepco Holdings, Inc.	3.8%	2.7%	4.2%		4.7%	10.0%	5.4%	9.2%
UIL Holdings	5.0%	0.2%	1.0%		2.7%	8.0%	3.0%	8.0%
Average	4.0%	2.5%	3.2%	3.1%	3.9%	7.3%	3.8%	**7.8%**
Median								**8.1%**
Composite		6.5%	7.2%	7.1%	7.9%	**11.3%**	7.8%	

Sources: Prior pages of this schedule.

Exhibit___(DCP-1)
Schedule 13
Updated

PPL ELECTRIC
TOTAL COST OF CAPITAL

ITEM	PERCENT	COST RATE	WEIGHTED COST
Long-Term Debt	46.41%	6.07% 1/	2.82%
Preferred Stock	10.46%	6.24%	0.65%
Common Equity	43.13%	9.63%	4.15%
Total	100.00%		**7.62%**

1/ Reflects the updated cost of long-term debt contained in Rebuttal Testimony of PPL Electric witness Paul R. Moul.

Exhibit___(DCP-1)
Schedule 14
Updated

PPL ELECTRIC
PRE-TAX COVERAGE

ITEM	PERCENT	COST RATE	WEIGHTED COST	PRE-TAX COST	
Long-Term Debt	46.41%	6.07%	2.82%	2.82%	
Preferred Stock	10.46%	6.24%	0.65%	1.12%	
Common Equity	43.13%	9.63%	4.15%	7.10%	(1)
TOTAL CAPITAL	53.59%		7.62%	11.03%	

(1) Post-tax weighted cost divided by .585065 (composite tax factor)

Pre-tax coverage = 11.03%/2.82%
3.91 X

Standard & Poor's Utility Benchmark Ratios:

	A
Pre-tax coverage (X) Business Position:	
3	2.8-3.4x
Total Debt to Total Capital (%) Business Position	
3	50 - 55%

Exhibit ___(DCP-2)
Schedule 1

Exhibit ___(DCP-2)
Schedule 1
Page 1 of 7

KODAK'S SURVIVAL STRATEGY (P.42) GRIDLOCK AT

The McGraw-Hill Companies

BusinessWeek

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It's a Low, Low, Low, Low-Rate World

Why money may stay cheap longer than you think

BY MICHAEL MANDEL & DAVID HENRY (P.32)

#BXBBGDD ******CR-LOT 10058D*C-012
#BWK0003877819/8# R0706T404 26MAY08
J099
MR DAVID PARCELL 002579
TECHNICAL ASSOCI 00022
1051 E CARY ST STE 601 0087
RICHMOND VA 23219-4029

CAPITAL

IT'S A LOW, LOW, LOW, LOW-RATE WORLD

Money is cheap. And some experts say it could stay that way for years. That's creating opportunity —and brand-new risks

BY MICHAEL MANDEL AND DAVID HENRY

WAIT A MINUTE—weren't long-term interest rates supposed to be a lot higher by now?

When the rate on the 10-year Treasury bond plunged from 6.5% in early 2000 to an average of 4% or so in 2003, the explanations were easy: tech bust, recession, weak capital spending, low inflation, steep rate cuts by central banks around the world. The low rates seemed perfectly normal—and sure to reverse on a dime when conditions changed.

Since then, plenty has changed. The Fed has hiked short-term rates by more than four percentage points. The global economy grew by 5.1% in 2006, the second-strongest performance in 25 years. Europe and Japan have recovered. Even tech spending seems to be on the rise, judging from Cisco Systems Inc.'s strong earnings report on Feb. 6. And yet—and yet!—10-year Treasury rates have risen only three-quarters of a percentage point. Real rates, which adjust for inflation, have barely budged.

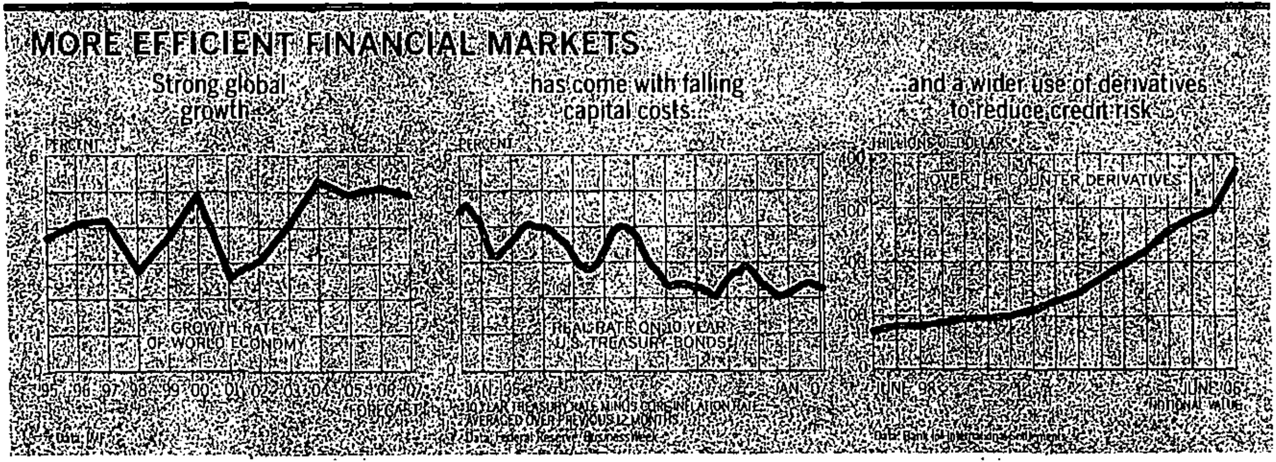
It isn't only a U.S. phenomenon. Ten-year euro bonds are yielding around 4% today, no higher than in 2003, despite much faster growth in the region. Real rates in the euro zone are up only a bit.

Borrowers, of course, are deliriously happy. Even the shakiest companies are seeing their debt costs plunge. The spreads on triple-C rated bonds and lower—the junkiest of junk—are at a record low 4.7 percentage points over ultrasafe Treasuries, compared with the previous record of 5.2 percentage points in 1997, according to Merrill Lynch & Co.

Most remarkably, the craziness isn't likely to stop anytime soon. The low

ROBERT NEUBECKER

Exhibit___(DCP-2)
Schedule 1
Page 3 of 7



*10-YEAR TREASURY RATE MINUS CORE INFLATION RATE AVERAGED OVER PREVIOUS 12 MONTHS

Data: IMF

Data: Federal Reserve, BusinessWeek

Data: Bank for International Settlements

cost of capital is probably going to last "five to seven years," says Samuel Zell, who as chairman of real estate firm Equity Office Properties Trust watched bidders wield cheap debt in a fight over his company. (Blackstone Group, with a $39 billion bid, won out on Feb. 7.) James W. Paulsen, chief investment strategist at Wells Capital Management, sees an even longer horizon: "This could be a prolonged cycle where the cost of capital is low [for] 10 or 20 years."

It is, indeed, a low, low, low-rate world.

Easy money is creating all sorts of economic benefits. Corporations are making capital investments again—and with their borrowing costs so low, profits are still zooming. Private equity firms are using loads of cheap debt to buy companies at jaw-dropping prices. Even the housing market, which boomed for five years on cheap money, hasn't fallen apart. It's gliding to a soft landing rather than a hard crash, allowing consumers to keep spending (page 35). "We are in this era where financial innovation and product structuring, particularly in the debt markets, has been very stimulative," says Henry H. McVey, chief U.S. investment strategist at Morgan Stanley. Zell puts the state of rates in similar terms: "I think that's going to be a growth accelerant around the world."

'FUTURE TURBULENCE'

BUT THE EASY MONEY also brings a slew of unexpected problems. Historically, risky borrowers have had to pay much higher interest rates on their debt. Now there's little penalty—and that means there's less incentive for companies to stay fiscally sound. Low rates aside, other borrowing terms are getting easier, too. Many debt deals being made today have fewer protections for investors in case companies can't pay. "I've never seen issuers have this much power," says Raymond G. Kennedy, a bond fund manager at PIMCO with 26 years' experience under his belt. Kingman D. Penniman, founder of KDP Investment Advisors Inc., a bond research firm, sees a dark side to this: "You're laying the groundwork for future turbulence."

The shift to a low-rate world doesn't mean lower volatility. In fact, excesses, crack-ups, and bad investments are not only possible but guaranteed. "Over the next several years there's likely to be some event that will widen out the spreads," says Zane Brown, director of fixed income at mutual fund manager Lord, Abbett & Co. But when the dust has cleared, he says, the world economy will likely be left with a lower cost of capital than the average over the past 5 to 10 years.

The shift to a low-rate world doesn't mean lower volatility

In some ways, it's the 1990s all over again. Back then, the info-tech boom created an unexpected boost in productivity that persists today. Now it looks like something analogous has hit the global financial markets. A combination of globalization, innovation, and good old-fashioned competition among markets has made it easier and cheaper to raise and deploy money. Borrowers now can draw funds from around the globe. And derivatives let financial institutions and traders manage their risks with mind-blowing precision. With Chicago, London, New York, and Frankfurt all jostling to be the world market leader, exchanges and financial institutions have an incentive to be cheaper, faster, more innovative (page 36).

At the same time, the low rates reflect major imbalances in the global financial system. The developed countries, led by the U.S., have systems that are good both *at raising money and allocating it. Emerging* markets such as China have only half of that equation: They can collect the money, but they don't have the financial institutions that can put it to the best use. According to a November, 2006, survey of executives by McKinsey & Co., only 40% of respondents in China and Latin America said their company's access to external funding is good or very good.

Eventually the financial systems in China and India will improve, and a lot more of their capital will be used at home. That won't happen anytime soon, though. In a new book, *The Next Great Globalization,* Federal Reserve Governor Frederic S. Mishkin writes: "It takes a long time for any nation to achieve strong property rights and an effective financial system."

For now, China and the other emerging markets are serving as key suppliers of capital in increasingly connected markets. "People are more willing to throw their money across borders and across currencies to get the highest yields," says David A. Wyss, chief economist at Standard & Poor's. Indeed, in just the past year, the value of outstanding international debt securities—debt raised in foreign countries or foreign currencies—has risen by 20%.

It's a continuation of a long-running trend. Since 1990, cross-border capital flows have been rising at a 10.7% annual rate, adjusted for inflation and exchange rate fluctuations, says a January, 2007, report from the McKinsey Global Institute. That's up from just 4.3% from 1980 to 1990.

An essential part of the globalization story is the adoption of the euro in 1999, which created a huge pool of highly mobile capital from lots of smaller pools.

CHARTS BY ERIC HOFFMANN/BW
ILLUSTRATION BY OTTO STEININGER

"The euro markets are today much bigger than what they would be if we had not had the euro," says Jerry del Missier, co-president of London-headquartered investment bank Barclays Capital.

The second key factor is the development of new trading instruments. Financial innovation isn't new, of course. Mortgage-backed securities date to the 1970s, and junk bonds came to life in the '80s. But innovation seems to have reached a fever pitch with the recent advances in collateralized debt obligations (CDOs), which keep borrowing costs low by dividing risks into big buckets and then reallocating them among hundreds of investors. With nearly half a trillion dollars' worth issued in 2006 alone, and with the risks widely dispersed, investors are willing to put more skin in the game. "Financial innovation in the form of CDOs has changed the risk premium associated with the bond market," says McVey.

MARKET FUEL

PUT THE TWO TOGETHER—bigger markets and innovation—and you have the makings of a global financial revolution. Adding more fuel, exchanges are becoming more entrepreneurial—which, as always, brings down costs. There's bustling competition from online exchanges as well. "When oil prices were very high and airlines needed to hedge the prices of jet fuel with options, they had no idea if investment banks were ripping them off, because there was no transparency in the price," says David Gershon, CEO of Super-Derivatives Inc., an online derivatives and options exchange. Gershon's outfit is among a handful of startups that allow investors to trade sophisticated instruments online. He argues that exchanges like his make markets more transparent and create more liquidity.

These changes have helped reduce the real cost of capital, best measured by the interest rate on low-risk Treasury bonds. Economists don't expect much of a change over the medium term. The Congressional Budget Office projects 10-year rates will average just 5.0% over the next three years, compared with 4.8% today.

Even more important is the decrease in the risk premium on corporate borrowing. Investment-grade bonds, issued by the healthiest companies, might enjoy a quarter-point decline in their spread over the low-risk Treasury rate long term. For junk bonds, says Wyss, "we could get a bigger permanent impact on keeping those spreads lower, maybe 100 basis points"—one full percentage point.

The increased efficiency has been ben-

ILLUSTRATION BY OTTO STEININGER

Why Housing Hasn't Hit the Skids

BY PETER COY

So this is the much-feared "housing bust"? Bust Lite is more like it. Existing-home prices are as high as they were a year ago, while sales have receded only to 2003 levels. The only extreme decline is in construction: Builders are trying to get rid of the houses they've already built before they put up more. The overhang of unsold homes could be back to normal by around midyear.

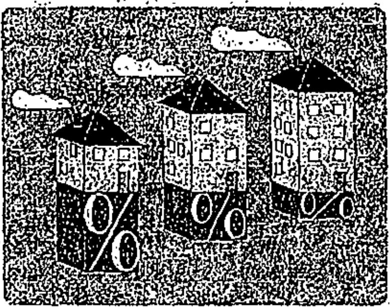
The credit goes, at least in part, to low interest rates. Fixed-rate 30-year mortgages averaged a modest 6.2% in the last quarter of 2006—well below a decade ago (chart). That, combined with income growth, means houses in most areas remain affordable even though prices rose more than 50% nationally in the past five years. The affordability index of the National Association of Realtors is still over 100, meaning a family making the median income can afford to buy a median-priced house.

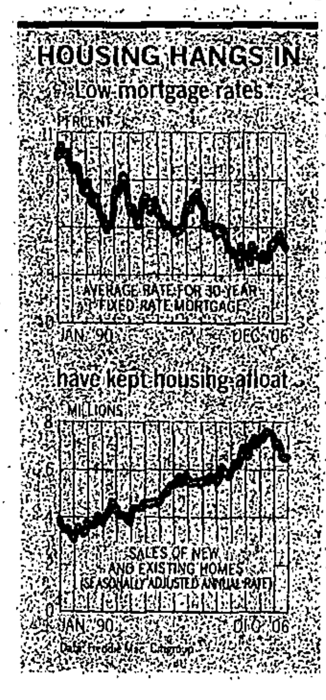
The market began gaining momentum in 2001 when the Federal Reserve started lowering rates to end a recession. Corporations cut back on borrowing, but homebuyers exploited the low-cost money. Says Citigroup economist Steven Wieting: "The housing sector acted as a bottom feeder, taking advantage of cheap capital flows."

The surprise is that low rates are still keeping a floor under housing. Thirty-year mortgage rates are no higher than in June, 2004, even though the Fed has since pushed up the federal funds rate by 4.25 percentage points. It's the same in Britain, where long-term rates have actually fallen since 2004 despite short-term rate hikes by the Bank of England. No surprise: After a brief lull, Britain's housing market is booming again.

Globalization and financial innovation are two key factors in keeping rates low. Investors know more about the loans they're buying, so they will pay more for them. "It's become a much more attractive asset class; hence more dollars are chasing the mortgage market, hence lower rates," says Bryan Whalen, a portfolio manager at Los Angeles-based Metropolitan West Asset Management. As recently as three years ago, he says, investors in mortgage-backed securities received two-page summaries of the portfolio. Now they get data on each loan.

Credit default swaps, which let people bet for or against a bond or loan's creditworthiness, have also improved transparency. If investors bet heavily against an issuer's securities, its lending costs are driven up. "This pushes out the marginal lenders," says Whalen. That creates a healthier market—and ultimately, lower rates.





Data: Freddie Mac, Citigroup

Exhibit___(DCP-2)
Schedule 1
Page 6 of 7

eficial so far. Companies gain from a lower cost of capital in the form of lower interest payments and higher profits. If rates had not stayed so low, corporate earnings would be about 10% lower than they are today.

Naturally, lower capital costs have made it easier to borrow. Duke Energy Corp., a $16.3 billion electric and gas utility based in Charlotte, N.C., plans to boost capital spending by $1 billion a year over the next three years to build new power plants to keep up with the growing demand. Duke may borrow the money instead of drawing down its cash, says David L. Hauser, chief financial officer, since "interest rates have remained surprisingly low." Robert M. La Forgia, chief financial officer of Hilton Hotels Corp., says low rates were critical to his company's ability to purchase its international hotel operations last February, uniting Hilton brands that had been apart for over 40 years. The company put together a $5.5 billion bank line at just 1.5 percentage points above the rate London bankers charge one another. "It's part of what made this deal possible," he says.

But the downside of the long-term trend is short-term financial market excess. It's here, and it's real. "The economy is robust, [but] we've entered into this new phase where the markets are financing riskier transactions," says Mariarosa Verde, head of the Credit Market Research team at Fitch Ratings Inc. Excess is especially evident in the corporate credit markets, where covenants, which protect investors by requiring companies to maintain healthy financial ratios, are becoming less restrictive. Some companies are jamming investors in other ways. When Pittsburg (Tex.)-based Pilgrim's Pride Corp. raised money to buy another poultry processor in January, it issued bonds that allow it to use projections rather than actual results to meet certain financial tests for borrowing more money. Pilgrim CFO Richard A. Codgill notes that the projections have to be "reasonable." Hospital chain HCA Ltd.'s latest bonds include some with provisions that let the company use debt instead of cash to make interest payments to bondholders. It works essentially like an IOU that increases HCA's debt down the road. Says Kennedy of PIMCO: "The bottom line is that when there's too much money in the market, [investors] lower [their] standards." What's more, many are depending on instruments that are highly leveraged, numbingly complex, and untested by a market downturn.

Then again, derivatives might cushion the blow when the reckoning comes. When hedge fund Amaranth Advisors went under, says Brown of Lord Abbett,

The Triumph of the 'Pork-Belly Crapshooters'

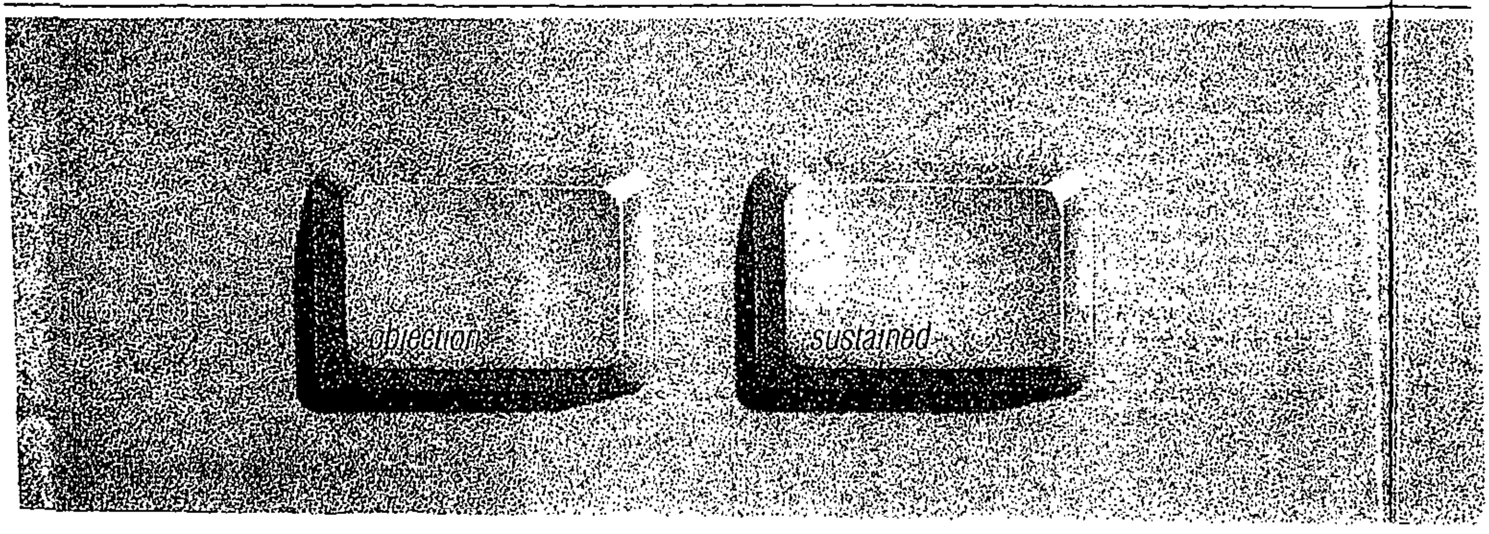
BY JOSEPH WEBER

Years from now, this decade might come to be viewed as the golden age of high finance. New markets are sprouting up everywhere, drawing huge amounts of capital and helping hold down rates. And the action is no longer confined to New York. Chicago in particular has emerged as a financial hub in its own right—with plenty of other cities coming on strong.

At the center of the explosion of markets and capital is vigorous competition. Banks, exchanges, and cities are vying for lucrative new trading business by focusing on three selling points: price, speed of execution, and innovation. The result can only benefit borrowers, who end up with a lower cost of capital.

The rise of Chicago's financial exchanges—and their current plans to expand—is emblematic of the creativity and entrepreneurial zeal worldwide that have helped create today's low-rate environment. In the 1970s, Leo Melamed was casting about for some way to increase the Chicago Mercantile Exchange's competitive edge against its crosstown rival, the Chicago Board of Trade. But the notion of looking beyond cattle, pigs, and other farmland products to currencies and financial instruments seemed crazy. "The world thought it was foolish," recalls the CME's former chairman and current *éminence grise*. "How could a bunch of pork-belly crapshooters be trusted with foreign exchange?"

Undaunted, Melamed went on to develop financial futures, arguably the most important new financial product since the rise of stock markets. Now futures on everything from Treasury securities to European weather allow corporate treasurers, investors, and traders to lay off risks. This allows capital to flow more freely, which is essential to keeping rates low. The growth has been staggering: Chicago's two big exchanges handled more than 2.1 billion contracts last year, or 9 million



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PARTNERS Duffy and Donohue will face stiff competition

contracts a day, up from 700,000 a day in 1986. And their innovations spurred the global market for over-the-counter derivatives, which has ballooned to around $300 trillion.

Like lots of revolutionary ideas, the notion behind financial futures is simple. For decades farmers would sell off parts of their crops months in advance to traders in the Chicago markets. The farmers got cash up front and didn't have to fret as much over bad weather or poor harvests. The traders got contracts they could then sell to others, making or losing money as harvest day neared and the crop looked more certain. By applying the same principle to currencies, first in 1972, the CME helped executives of multinational companies lay off the risk of fluctuating pounds or francs. Since then, the CBOT and CME have expanded to other types of derivatives and are still adding more. Soon traders will be able to wager on the price of commercial real estate and the likelihood that companies such as Tribune Co. will go bankrupt.

But the global competition is forcing the Chicago exchanges to look for bigger scale and more efficiency to offer investors and borrowers better deals. Not only do they do battle with energy-oriented futures bourses in the U.S. but they also face Eurex, a European market that now leads the world in derivatives trading. Soon, China will step up its participation in futures with a new bourse in Shanghai expected to open this year. The appeal of futures is even blurring the lines among exchanges, as the New York Stock Exchange, armed with a new derivatives unit that will come in with its Euronext acquisition, looks to expand.

All that competition is the reason the CME and the CBOT plan to merge by midyear in an $8 billion deal. The CME hosts stock index and currency futures, while the CBOT is home to Treasury contracts. CME Chairman Terrence A. Duffy and CEO Craig S. Donohue will hold the same positions at the combined CME Group. Together, the two exchanges will shoot past Eurex, with as many as 600 million more contracts traded yearly.

The exchanges are also hungrily eyeing expansions into the OTC market, a move that could provide investors and borrowers with more choices. Eurex soon plans to start trading a contract based on European credit default swaps, itself a multitrillion-dollar market. "The new Chicago entity is going to be under terrific competition as global alliances appear," says Michael Henry, a senior executive in the capital markets practice at consulting firm Accenture Ltd. For its part, the CME has teamed up with Reuters Group to push into the foreign exchange market and the OTC market for other derivatives known as interest-rate swaps.

Bold ideas in finance underlie all the growth. And thanks to expanding global competition, there's plenty of reason to believe it will continue. "If we weren't innovative throughout the years, we'd still be trading butter and eggs," says CME's Duffy. As long as there's money to be made and the ideas keep coming, the cost of capital will drop even further.

Chicago's innovations are driving growth in other markets

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part of its losses were covered in the derivatives markets. "It barely caused a ripple." Adds del Missier: "We haven't done away with dislocations in markets, but markets are much more able to deal with dislocations, and their impact will be less."

Over the long term, the big issue is the development of better financial systems in China, India, and other emerging markets. Right now money is pouring into real estate rather than infrastructure, education, and other essential investments. As financial systems improve in these countries, they will likely make better use of their own money. When that happens, the cost of capital around the world will go up.

But that's a long way off. In the meantime, rates are likely to remain low. "Whatever shocks are ahead," says del Missier, "the markets are better positioned to deal with them than they've ever been." ■

–With Mara Der Hovanesian in New York, Christopher Palmeri in Los Angeles, and Stanley Reed in London

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OCA STATEMENT NO. 4

AUG 13 2007

Hbg JK

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

PPL ELECTRIC UTILITIES CORPORATION	))	DOCKET NO. R-00072155

DOCUMENT FOLDER

DIRECT TESTIMONY OF

ROGER COLTON

TOPIC ADDRESSED:
UNIVERSAL SERVICE PROGRAM
DESIGN AND RATE RECOVERY

RECEIVED

AUG 14 2007

PA PUBLIC UTILITY COMMISSION
SECRETARY'S BUREAU

ON BEHALF OF THE

OFFICE OF CONSUMER ADVOCATE

JULY 2007

Q. PLEASE STATE YOUR NAME AND ADDRESS.

A. My name is Roger Colton. My address is Fisher, Sheehan & Colton, Public Finance and General Economics, 3 Warwick Road, Belmont, Massachusetts, 20478.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am a principal in the firm of Fisher Sheehan & Colton, Public Finance and General Economics of Belmont, Massachusetts. In that capacity, I provide technical assistance to a variety of federal and state agencies, consumer organizations and public utilities on rate and customer service issues involving telephone, water/sewer, natural gas and electric utilities.

Q. FOR WHOM ARE YOU TESTIFYING IN THIS PROCEEDING?

A. I am testifying on behalf of the Pennsylvania Office of Consumer Advocate (OCA).

Q. PLEASE DESCRIBE YOUR PROFESSIONAL BACKGROUND.

A. I work primarily on low-income utility issues. This involves regulatory work on rate and customer service issues, as well as research into low-income usage, payment patterns, and affordability programs. At present, I am working on various projects in the states of New Hampshire, New Jersey, Pennsylvania, Indiana, Michigan, Illinois, Iowa, Arkansas and New Mexico. My clients include state agencies (*e.g.*, Pennsylvania Office of Consumer Advocate, Iowa Department of Human Rights), federal agencies (*e.g.*, the U.S. Department of Health and Human Services), community-based organizations (*e.g.*, Community Action of New Mexico, Coalition to Keep Indiana Warm), and private utilities (*e.g.*, Entergy Services, Detroit Water and Sewer Department, NIPSCO, Citizens Gas and Coke Utility, Vectren Energy). In addition to state- and utility-specific work, I engage in national work in the United States and Canada. I am working on a national study of the responses of water utilities to the payment troubles of residential customers for the American Water Works Association Research Foundation. I am also part of a team that is performing a multi-sponsor national study of low-income energy assistance programs.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND.

A. After receiving my undergraduate degree from Iowa State University (1975), I obtained further training in both law and economics. I received my law degree from the University of Florida in 1981. I received my Masters Degree (economics) from the McGregor School (Antioch University) in 1993.

Q. HAVE YOU EVER PUBLISHED ON PUBLIC UTILITY REGULATORY ISSUES?

A. Yes. I have published more than 80 articles in scholarly and trade journals, primarily on low-income utility and housing issues. I have published an equal number of technical reports for various clients on energy, water, telecommunications and other associated low-income utility issues. A list of my professional publications is appended as Attachment A.

Q. HAVE YOU EVER TESTIFIED BEFORE THIS OR OTHER UTILITY COMMISSIONS?

A. Yes. I have previously testified before the Pennsylvania Public Utility Commission (PUC) on numerous occasions regarding low-income energy, water and telecommunications program design and cost recovery issues. I have also testified in regulatory proceedings in more than 30 states and various Canadian provinces on a wide range of low-income utility issues. Proceedings in which I have previously appeared as an expert witness are listed in Attachment A.

Q. PLEASE EXPLAIN THE PURPOSE OF YOUR TESTIMONY.

A. My testimony has four objectives.

- ➢ First, I will consider the reasonableness of the universal service cost recovery sought by PPL Electric Utilities Corp. ("PPL" or "Company").
- ➢ Second, I will consider the sources of funding for the Company's OnTrack program (sometimes referred to as the Customer Assistance Program or CAP) outside simply passing through OnTrack expenses to all other ratepayers; and
- ➢ Third, I will consider the reasonableness of the inter-class cost allocation proposed by the Company for its universal service costs;
- ➢ Finally, I will consider the reasonableness of certain program modifications that the Company has proposed to adopt in this proceeding.

I conclude that the Company overstates the universal service costs to be recovered through rates. Second, I conclude further that certain offsets should be adopted in compliance with the Pennsylvania Public Utility Commission's (Pennsylvania PUC) CAP Policy Statement. Third, I conclude that the Company's universal service costs should be allocated to all customer classes. Finally, I conclude that the Company's proposed ceiling on CAP credits should be modified should it be adopted.

PART 1. UNIVERSAL SERVICE COST RECOVERY.

Q. PLEASE EXPLAIN THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY.

A. In this section of my testimony, I consider the reasonableness of the universal service expenses that the Company proposes to pass through to residential ratepayers. The Company proposes to recover its universal service costs through a universal service rider ("Rider" or "USR"). The Rider would impose a charge of 6.54% against all residential distribution revenue in order to generate funding for the Company's universal service programs.

Q. IS THERE ANY INITIAL CORRECTION TO THE COMPANY'S FILING THAT YOU WISH TO MAKE?

A. Yes. Before I begin my substantive discussion, the Company has acknowledged that it made a minor error in the determination of its residential distribution revenue. It based its 6.54% on an application of the USR against only the distribution revenue under its RS rate schedule. It should have also included the revenue from its RTS and RTD rate schedules. The Company acknowledges that "The 6.54% in the proposed tariff was calculated incorrectly by dividing the USR costs by the distribution revenue for only Rate Schedule RS. The USR percentage should be calculated by dividing the USR costs by the distribution revenue for Rate Schedules RS,RTS and RTD. The correct percentage would be 6.53%." (OCA-XI-14).

Q. WHAT ASPECTS OF THE PROPOSED UNIVERSAL SERVICE RIDER DO YOU FOCUS ON?

A. I focus my attention on the expenses associated with the Company's CAP, which it calls the OnTrack program. The Company proposes to collect three expense components associated with its OnTrack program: (1) the CAP credit, which is the shortfall between the OnTrack participant's fully-embedded bill and the customer payment under OnTrack; (2) the arrearage forgiveness credits provided to OnTrack participants; and (3) OnTrack administrative expenses.

Q. EXPLAIN WHY YOU FOCUS ON THESE THREE PROGRAM COMPONENTS.

A. The Company proposes to collect $19 million in OnTrack expenses through its USR. The $19 million was based on a "baseline budget" for OnTrack as follows:

➢ Cap Credits:	$12.9 million
➢ Arrearage forgiveness:	$ 4.5 million
➢ Administration:	$ 1.6 million

(OCA-XI-13(C)). When asked to identify any "other" costs of the OnTrack program, the Company reported that "all of PPL Electric's costs for OnTrack appear as CAP credits, arrearage forgiveness or administration." (OCA-XI-13(D)).

Q. HOW DID THE COMPANY CALCULATE THE ON TRACK BUDGET FOR WHICH IT SEEKS COST RECOVERY THROUGH THE UNIVERSAL SERVICE RIDER?

A. The Company cannot provide any back-up support for its requested $5.8 million in additional funding for OnTrack. The Company reports that the additional $5.8 million in CAP funding it seeks in this proceeding is based on its estimated $19 million budget. "PPL has no detailed work papers regarding the requested additional funding of $5.8 million for its Customer Assistance Program (known as OnTrack). The $5.8 million is simply the difference between the Company's 2007 OnTrack budget ($19 million) and the amount approved by the Commission ($13.2 million) in PPL Electric's most recent distribution base rate case at Docket No. R-00049255." (OCA-XI-8).

The Company, however, cannot provide any back-up for its estimated $19 million OnTrack budget. The Company stated that "PPL Electric does not have any work papers showing the derivation of the $19 million associated with participation in OnTrack. Rather, the Company considered the existing number of OnTrack customers at the end of 2006, data from the 2000 U.S. Census, the average monthly net enrollment and the average annual cost (approximately $850) per OnTrack customer to develop its proposed budget of $19 million." (OCA-XI-15). No data was provided on what "average net enrollment" figure was used or how it was calculated. No indication was provided on what "data from the 2000 U.S. Census" was used in developing the estimate. No information was provided on the derivation of the "approximately $850" "average annual cost" for each OnTrack customer.

Moreover, saying that it was "difficult to provide an accurate annual budget," the Company could not indicate to OCA how its proposed $19 million OnTrack budget would differ based upon whether the Company had a participation of 20,000 or 24,000 participants (or any 1,000 participant increment in between). (OCA-XI-12). At an average CAP cost of $850 per participant, however, a $19 million budget would support a CAP participation level of between 22,000 (22,000 participants * $850/participants = $18.7 million) and 22,500 (22,500 participants * $850 per participant = $19.125 million).

Q. DOES THE LACK OF BUDGET DETAIL GIVE RISE TO CONCERN ABOUT THE COMPANY'S PROPOSAL FOR AN ANNUAL UNIVERSAL SERVICE RIDER RECONCILIATION?

A. Yes. The lack of detail available to support the Company's proposed Universal Service Rider gives rise to concern about whether the Company will have sufficient information to support an annual reconciliation. The Company should be required to provide confirmation that their information technology will be sufficient to track this information on an ongoing basis, to archive that information, and to access that information once archived.

Consider, for example, the impact that a changing mix of customers by Federal Poverty Level would generate for the OnTrack program. The mix of customers refers to the proportion of OnTrack participants who have incomes in various ranges of Poverty Level (e.g., 0-50% of Poverty Level; 51-100% of Federal Poverty Level; 101-150% of Federal Poverty Level). As the income (by Poverty Level) increases, the CAP credit provided to that customer will decrease (and, conversely, a decreasing income will result in increasing CAP credits). Even should the total participation level in the OnTrack program remain the same, therefore, if the *mix* of OnTrack participants by Poverty Level changes, the overall costs (along with the average costs) of the program will change as well. The Company, however, can not provide a breakdown of CAP credits by Federal Poverty Level for 2006. (OCA-XI-18; OCA-XI-19). Nor could the Company provide a breakdown of the different "payment options" by Federal Poverty Level. (OCA-XII-6). Having such information would seem to be essential to undertake an appropriate reconciliation. Working from historic averages may or may not reflect actual ongoing experience.

In addition, given the way that the PPL program operates, it is necessary not only to *know the total number of participants in the OnTrack program in any given month in* order to know the OnTrack credits provided (either toward current bills or toward preprogram arrears), it is necessary to know how many of those OnTrack participants made their current bill payments in a timely fashion (and how the nonpaying or late-paying customers broke-down by Federal Poverty Level and by payment option). Under the PPL program, a customer not making a timely payment toward his or her current bill loses his or her CAP credit for that month of nonpayment or late payment. While the Company can provide the average amount owing at the time of nonpayment, however, it cannot provide the average amount of OnTrack CAP shortfall for the months of nonpayment at the time that customers are removed from the program (for nonpayment). (OCA-XII-12).

Before approving an annual reconciliation process for PPL, the Commission should require PPL to document that it has the capacity to generate, archive and access the data needed to ensure that an annual reconciliation process can accurately occur.

A. OnTrack Administrative Expenses.

Q. WHAT ADJUSTMENT DO YOU PROPOSE TO MAKE TO THE PROPOSED RECOVERY OF ON TRACK ADMINISTRATIVE EXPENSES?

A. The Company proposes to collect $1.6 million in OnTrack administrative expenses through its Universal Service Rider (USR). (OCA-XI-13). I propose to exclude all elements of the administrative expenditure budget, with the exception of "work by outsiders" from recovery through the OnTrack rate rider recovery. The budgeted expenses identified by PPL are set forth in Schedule RDC-1.

Q. CAN YOU EXPLAIN THE RATIONALE FOR THIS EXCLUSION?

A. Let me focus on the "wages" component of the administrative budget first. The wages the Company proposes to collect through the USR cannot be seen as a "universal service" expense. They are instead generalized customer service expenses that have simply been allocated to the universal service programs. The Company acknowledges that "PPL Electric does not have staff positions dedicated exclusively to the administration of OnTrack. Various staff positions allocate a portion of their time to OnTrack." (OCA-XI-37). The administrative budget, for example, seeks to recover part of the wages for the Company's "Manager—Regulatory Program and Business Services." Moreover, the Company simply allocates part of the expenses associated with its "Customer Representatives" and "Steno/Clerks" to the universal service program. (OCA-XI-37).

These staff expenses do not vary based on the existence, or size, of the universal service program. The expenses, as well as the other administrative expenses identified in Schedule RDC-1, do not increase if the program expands and do not decrease if the program contracts. They are not universal service expenses. The total adjustment is a decrease in OnTrack expenses of $1,029,213.

The conclusion that the "salaries and benefits" expense components included in the OnTrack budget should not be included in the USR is bolstered by the fact that the Company proposes to collect overhead costs through the Rider. The Company acknowledges that "overhead expenses are included as part of the costs associated with salaries and benefits." (OCA-XI-37, OCA-XI-38, OCA-XI-39). Company overhead expenses are not properly categorized as a "universal service" expense. These expenses are not incremental to the universal service program. They are not incurred because of the program. They do not increase as the program expands or decrease as the program contracts. They further evidence the conclusion that it is inappropriate to include staff expenses in the Universal Service Rider.

2. OnTrack Credits.

Q. PLEASE EXPLAIN THE SECOND GENERAL CATEGORY OF UNIVERSAL SERVICE EXPENSES THAT YOU HAVE EXAMINED IN YOUR REVIEW OF THE ON TRACK PROGRAM BUDGET THE COMPANY PROPOSES TO COLLECT THROUGH ITS USR?

A. The second category of universal service expenses that I have examined involves the "CAP Credits" which the Company proposes to collect through its USR. The Company has included $12.9 million of CAP credits in its USR cost recovery. (OCA-XI-13). At a participation rate of 22,500 customers, as determined above, this implies a net CAP credit (CAP credit net of LIHEAP offsets) of $573 per participant. This compares to an average annual CAP credit of $560 in 2006 (OCA-XI-32). There are three adjustments that I make to the proposed recovery of CAP credits:

- An adjustment to reflect those CAP credits that remain unpaid to OnTrack participants because the OnTrack participant did not make a timely current bill payment;
- An adjustment to reflect the imposition of a ceiling on the grant of CAP credits; and
- An adjustment to prevent the double-recovery of CAP credits through the Company's uncollectible expenses.

1. CAP Credits Unpaid due to Untimely Bill Payment.

Q. CAN YOU REPLICATE THE CALCULATION OF AN AVERAGE 2006 CAP CREDIT OF $560?

A. Yes. Schedule RDC-2 replicates the calculation of an average 2006 CAP credit of $560. The Schedule presents the total CAP credits reported by month in 2006. (OCA-XI-33). It presents the total number of CAP participants reported by month in 2006. (OCA-XI-11). It presents the total LIHEAP dollars offset against the CAP credits, averaged over all CAP participants. (OCA-XI-10). As shown in Schedule RDC-2, this calculation yields an average 2006 CAP credit of $551 (compared to the $560 reported by the Company in response to OCA-XI-32).

Q. DOES THIS CALCULATION DEMONSTRATE THAT PPL OVERSTATES ITS CAP CREDITS IN CALCULATING THE UNIVERSAL SERVICE RIDER?

A. Yes. This calculation shows that PPL overstates the calculation of its CAP credits in developing the estimated budget for its Universal Service Rider. Schedule RDC-2 documents that the Company is proposing to collect CAP credits as though 100% of its CAP participant population makes 100% of their payments every month.

Q. PLEASE EXPLAIN THE PROBLEM WITH PPL'S PROPOSAL TO COLLECT CAP CREDITS AS THOUGH 100% OF ITS ON TRACK POPULATION MAKE 100% OF THEIR PAYMENTS EACH MONTH.

A. Schedule RDC-2 shows that the $12.9 million CAP credit budget upon which the Company's proposed USR is based assumes that 100% of its CAP customers make their monthly bill payments on a full and timely basis each month. This assumption is necessary for the Company to incur a CAP credit expense for each participant each month. PPL's OnTrack program, however, is designed so that, in the event that a customer does not make a timely payment, the customer loses his or her OnTrack credit for that month. As the Company states: "PPL Electric requires timely payment of monthly OnTrack bills (i.e., within five (5) days past the due date of the bill) for customers to receive OnTrack credits." (OCA-XII-16). The Company explained its process as follows:

> If an OnTrack customer makes a timely payment (i.e., within five (5) days after the due date of the bill), he or she receives CAP credits, which is the difference between the customer's actual electric bill and his or her OnTrack monthly payment amount. PPL Electric grants CAP credits at the time of billing. If the customer does not pay within the five (5) day window, the Company's billing system automatically reverses the transaction.

(OCA-XII-17). The Company continues that the opportunity to earn the CAP credit lapses at the time of the billing due date (plus five days). "PPL Electric has no process for granting CAP credits to customers who subsequently "cure" their missed payments." (OCA-XII-18). For example, "customers removed from OnTrack for non-payment of bills are put into the Company's normal collection processes and are billed the full amount of their kWh usage. However, if customers pay their missed OnTrack payments and are reinstated in the program, they do not "earn" any CAP credits or arrearage forgiveness at the time of their reinstatement." (OCA-XII-18).

Q. TO WHAT EXTENT DO ON TRACK CUSTOMERS FAIL TO MAKE TIMELY BILL PAYMENTS?

A. Under the PPL OnTrack program, all program participants enter the program with preprogram arrears subject to forgiveness. (OCA-XI-25, OCA-XI-26). Virtually all OnTrack participants have a preprogram arrears subject to forgiveness. In December 2006, for example, while there were 20,721 OnTrack participants (OCA-XI-11), only 207 had a preprogram arrears of $0. (OCA-XI-29). In May 2007, while there were 21,573 OnTrack participants (OCA-XI-11), only 178 had a preprogram arrears of $0. The required $5 customer copayment toward his or her preprogram arrears is part of the payment that is due each month from the OnTrack participant. (OCA-XII-10).

This information is significant in that one can track the extent to which customers who are eligible for arrearage forgiveness actually earn the forgiveness for which they are eligible. When OnTrack participants do not make their bill payments on time, those customers lose their ability to earn that component of their arrearage forgiveness. Schedule RDC-3 presents this data for 2006. Schedule RDC-3 shows that, over the course of 2006, only 71% of the customers who were eligible for arrearage forgiveness actually received that forgiveness. For our purposes here, if a customer has failed to make the payment required to earn his or her arrearage forgiveness, that customer has also failed to make the current payment needed to earn his or her current month CAP credits.

Q. WHAT DO YOU PROPOSE?

A. The estimated CAP credits that the Company uses to support the budget underlying its proposed Universal Service Rider should not be allowed to assume that 100% of the Company's CAP participants will collect 100% of their CAP credits in every month. The Company's own data documents that only 71% of CAP customers make their current monthly bill payments in a timely manner. I propose that the Company's budget for CAP credits be reduced to reflect the rate at which CAP participants made timely current bill payments in the preceding twelve months. In accordance with that principle, I have reduced the CAP credits to 71% of the budget proposed by the Company.

2. Rate Recovery Impact of Ceiling on CAP Credits.

Q. IS THERE A SECOND ADJUSTMENT THAT YOU PROPOSE TO MAKE TO THE BUDGET FOR CAP CREDITS?

A. The Company based its estimated budget for the Company's OnTrack program on the average CAP credits from 2006. The Company states that it used, among other things, "the average annual cost (approximately $850) per OnTrack customer." (OCA-XI-15). Use of the average annual cost from 2006 would overstate the OnTrack budget on a going forward basis.

Q. PLEASE EXPLAIN WHY USING THE 2006 AVERAGE CAP CREDIT WOULD NOT ACCURATELY REFLECT CAP CREDITS ON A GOING FORWARD BASIS.

A. PPL Electric has proposed a ceiling on CAP credits on a going forward basis. The Company states that its "proposed three-year Universal Service and Energy Conservation Plan includes a stay-out provision for OnTrack customers who exceed their maximum annual CAP credits allowance." (OCA-XII-14). The Company proposes to implement a CAP credit ceiling of $1,800 for home heating customers (OCA-XII-6) and of $700 for non-heating customers. (OCA-XII-7). The Company reports that 2,570 OnTrack heating customers would have been removed from OnTrack in 2006 due to "exceeding the $1,800 limit on CAP credits" had the CAP credit ceiling been in effect. (OCA-XI-20). The Company stated that 1,567 homeowners and 1,003 renters would have been removed from CAP due to exceeding an $1,800 CAP credit ceiling. Similarly, 2,968 OnTrack participants would have been removed from CAP in 2005 for exceeding the $1,800 CAP credit ceiling, had such a ceiling been in effect for 2005. (OCA-XI-20). In 2006, PPL had an average monthly OnTrack participation of 17,788. (OCA-XI-11). The Company had a year-end OnTrack participation of 20,761. (OCA-XI-11). Accordingly, depending on whether you calculate it on an average basis, or on a year-end basis, implementation of the $1,800 CAP ceiling would have resulted in a removal of between 12 ½% (2,570 / 20,761 = 0.124) and 14 ½% (2,570 / 17,788 = 0.144) of the Company's CAP participants with the highest level of CAP credits. Importantly, the Company does not propose simply to charge the excess credits over $1,800 to the CAP participant, but rather to remove the participant from the OnTrack program completely. (OCA-XII-14).

In addition to excluding heating customers, the Company proposes to remove OnTrack participants whose CAP credits exceed $700 when those participants are non-heating electric customers.

While I comment on the stay-out provision in my discussion of program issues below, my discussion here is limited simply to cost-recovery. Should the Company remove 12% – 14% of its highest cost CAP participants from its program, to use the historic average level of CAP credits will clearly overstate the estimated future cost of the program.

Q. CAN YOU ESTIMATE THE ADJUSTMENT THAT SHOULD BE MADE TO ACCOUNT FOR THE CAP CREDIT CEILING?

A. Yes. We know that 60% of the OnTrack participants that received CAP credits of more than $1,800 in 2006 received CAP credits of between $1,800 and $2,100. We know that 40% of the OnTrack participants that received CAP credits of more than $1,800 in 2006 received CAP credits of more than $2,100. (OCA-XI-18). Since the impact of the Company's proposal is to exclude the excess CAP credit from payment by the program, I calculate an exclusion for the increment of CAP credits over $1,800 for 12.5% of the estimated OnTrack population I establish above (22,500). I have set forth the calculation in Schedule RDC-4. The total reduction in the budgeted CAP credits to be recovered through the USR is $815,625

3. Double Recovery of CAP Credits.

Q. IS THERE A THIRD ADJUSTMENT THAT YOU PROPOSE TO MAKE TO THE ON TRACK CAP CREDIT BUDGET?

A. Yes. PPL proposes to recover 100% of the CAP credits that it provides to its program participants through its USR. Such a 100% recovery through the USR is inappropriate. PPL should be allowed to recover only the incremental expenses imposed on the Company as a result of a customer's participation in CAP. To the extent that expenses have already been included in base rates, those expenses should not be recovered a second time through the Company's proposed USR. Some expenses, particularly uncollectibles, are already reflected in base rates. Dollars of CAP shortfall that are already included in the Company's uncollectible expenses are not incremental universal service expenses to the Company and should not be recovered again through the universal service surcharge.

Q. CAN YOU ILLUSTRATE HOW COLLECTING 100% OF CAP CREDITS THROUGH UNIVERSAL SERVICE RIDER COULD RESULT IN A DOUBLE RECOVERY OF UNCOLLECTIBLE EXPENSES?

A. The most recent annual universal service report published by the Bureau of Consumer Services (BCS) reports that in 2005, PPL had $8,329,473 of gross write-offs associated with "confirmed low-income customers." (page 21). BCS reports that the low-income gross write-off was on a revenue base of $160,476,569 (page 63) for a write-off rate of 5.19% (page 23).

BCS makes a specific point of noting, however, that the gross write-off figure for confirmed low-income customers, includes neither CAP credits nor CAP arrearage forgiveness credits. As can be seen, a PPL customer must be in one of two mutually exclusive groups of customers. Either a customer is a CAP (OnTrack) participant, in which case the CAP credits are collected through the universal service surcharge as described above. Or, a customer is ***not*** a CAP (OnTrack) participant, in which case unpaid bills are collected from ratepayers as an uncollectible expense.

Q. WHY DOES A PROBLEM ARISE?

A. The problem arises because when a customer moves from one of those two mutually exclusive groups to the other, the dollars associated with the customer's bill do not. In particular, the dollars representing that customer's CAP credits will be included in rates through the universal service surcharge as "new" CAP credits. In fact, however, not all of these CAP credits are "new" expenses. Some portion of these dollars of billing that will not be collected from the customer have simply been moved from the non-CAP participant population to the CAP participant population. Those dollars are non-incremental CAP expenses.

Q. PLEASE EXPLAIN HOW PARTICIPATION IN CAP AFFECTS THE COMPANY'S WRITE-OFF FIGURES.

A. Low-income customers that were not participating in CAP at the end of 2006 are included in the gross write-off figures I cite above. When those low-income customers become participants in OnTrack, the CAP shortfall associated with their account will be recognized as a CAP expense and collected through the universal service program. As such, the Company collects the entire CAP shortfall for these new CAP participants as though that shortfall is a "new" expense. As I explain above, however, CAP participants and CAP non-participants are mutually exclusive groups of customers. For ratemaking purposes, when a customer moves from one group (CAP non-participant) to the other (CAP participant), to reflect all of the expenses associated with their participation in the *new* group, without removing any of the expenses associated with their participation in the *old* group, will result in the expenses of the CAP participants being reflected twice, both in base rates *and* in the universal service surcharge.

Q. IS IT NOT POSSIBLE THAT THERE WILL BE CUSTOMERS LEAVING CAP THAT WILL FALL INTO ARREARS AGAIN AND CONTRIBUTE TO RESIDENTIAL UNCOLLECTIBLES?

A. Yes. To the extent that there is a churn in the Company's program, with no net increase in the CAP participation rate, there is no issue with respect to the double-recovery of non-incremental expenses. The issue arises only when there is a net increase in the participation in CAP above the level at the time base rates were set. In circumstances involving a net increase in CAP participation, the CAP credits associated with the net increase may need to be reduced in order to prevent the double-collection of expenses, once through residential uncollectibles and again through the CAP credits.

Q. IS THE ISSUE YOU RAISE RELATED TO AN ABSOLUTE DECREASE IN UNCOLLECTIBLES ATTRIBUTABLE TO CAP?

A. No. The enrollment of customers in CAP should result in improved collections and a decrease in the Company's uncollectible expense. This is not that issue. My discussion above instead relates only to preventing a double-recovery of non-incremental expenses. It does not address whether CAP will help the Company to reduce its uncollectible expenses.

Q. HAVE YOU ESTIMATED THE POSSIBLE MAGNITUDE OF THIS POTENTIAL DOUBLE-RECOVERY?

A. Yes. The Company experiences an average per participant CAP shortfall of $656 before LIHEAP offsets. The participation in OnTrack at year-end 2006 was 20,721. There is a projected increase in CAP participation of roughly 2,000 customers (to 22,500). Given the average per-participant CAP credit of $656, this net increase in CAP enrollment will result in a net increase in the CAP shortfall of $1,312,000 (2,000 x $656 = $1.312 million). Given a gross write-off rate for the revenue of confirmed low-income customers of 5.19%, there would be $70,000 ($1,312,000 x 0.059 = $68,092) in CAP credits that would be included in the universal service surcharge that may already be recovered in the base rates. This double recovery involves the extent to which the CAP credits are non-incremental expenses.

This dollar figure is not based on any assertion that these credits will not be granted. Instead, this figure is based on the observation that these dollars have already been reflected in existing rates and thus do not represent incremental expenses to the Company. Nor is it an assertion that the Company should not collect 100% of its CAP shortfall. My discussion above simply shows that part of the shortfall is collected through the USR and a different part of the shortfall is collected through existing rates.

Q. IF THERE IS A SMALLER NET INCREASE IN CAP PARTICIPATION RATES, WOULD THE DOUBLE RECOVERY BE SMALLER?

A. Yes. If there are fewer net additions to the CAP participant population –net additions to CAP participation occur when the number of customers joining CAP exceed the number of customers leaving CAP-- the double recovery would be smaller. Similarly, if the average CAP credit were smaller, the double recovery would be smaller as well. If the growth in OnTrack participation is greater than to 22,500, or if the CAP credit for OnTrack participants is greater than $656, the double recovery would be greater.

Q. ARE YOU SUGGESTING THAT THE COMPANY WILL REDUCE ITS UNCOLLECTIBLE EXPENSES BECAUSE OF CAP?

A. Whether or not PPL reduces its uncollectible expense through OnTrack is a ***different*** issue than that which I identify above. In my discussion above, I use an uncollectible rate of 5.19% for the confirmed low-income customers. There is a reasonable expectation, however, that when PPL makes the bills to its confirmed low-income customers more affordable, that uncollectible rate will be reduced to something less than 5.19%. If the uncollectible rate can be reduced to 2% because of the affordability of the CAP bills, in other words, the Company will experience real dollar savings. That is, however, an entirely different issue.

C. Arrearage Forgiveness Credits.

Q. DOES THE SAME COST RECOVERY PRINCIPLE THAT APPLIES TO CURRENT BILL PAYMENTS AND CAP CREDITS APPLY EQUALLY TO CURRENT BILL PAYMENTS AND ARREARAGE FORGIVENESS CREDITS?

A. Yes. Like the CAP credits toward current monthly bills, arrearage forgiveness credits must be earned through participants making timely bill payments. As I discuss in detail above, the Company's proposed OnTrack budget assumes that OnTrack participants make 100% of their payments 100% of the time on a timely basis. If the participants do not make full and timely payments, they forfeit the ability to earn the CAP and arrearage forgiveness credits for that month.

I document in detail above the fact that only 71% of OnTrack participants that were eligible to earn arrearage forgiveness actually earned their credits. (Schedule RDC-3). Accordingly, for the same reasons I reduce the CAP credit budget, I propose to reduce the budget for arrearage forgiveness to 71% of the budget which assumes a 100% payment rate.

D. The Proposed Universal Service Rider.

Q. PLEASE EXPLAIN THE IMPACT OF YOUR PROPOSED ADJUSTMENTS ON THE COMPANY'S UNIVERSAL SERVICE RIDER.

A. The Company proposed a Universal Service Rider of 6.53% to generate universal service funding of $27,896,000. (OCA-XI-14). Of that $27,896,000, $19.0 million was for OnTrack expenses, consisting of $12.9 million for CAP credits, $4.5 million in arrearage forgiveness credits and $1.6 million in administrative expenses. (OCA-XI-13). I propose to reduce CAP expense recovery through the Rider by $6,958,930. The resulting universal service budget of $20,937,070 would, when spread over distribution revenues of $427,036,577 (OCA-XI-14) result in a Universal Service Rider, unadjusted for the CAP offsets I discuss below, of 4.90%. A summary of the adjustments is presented in Schedule RDC-5.

Q. ARE YOU PROPOSING THAT THE COMPANY SHOULD NOT RECOVER THE ON TRACK ADMINISTRATIVE EXPENSES IT HAS PROPOSED TO INCLUDE IN THE UNIVERSAL SERVICE RIDER?

A. No. I simply propose that administrative expenses are inappropriate to include in the Universal Service Rider. Those administrative expenses should be recovered through base rates. Any final revenue requirement adopted in this case will need to address these administrative expenses.

PART 2. CAP COST OFFSETS.

Q. WHAT IS THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY?

A. In this section of my testimony, I assess the extent to which there should be offsets to the total CAP expenses generated by the PPL OnTrack program.

Q. WHY DO YOU INCLUDE OFFSETS AS A PART OF THE USR RECOVERY OF UNIVERSAL SERVICE EXPENSES?

A. The Pennsylvania Commission has directed that one source of funding for the CAP programs of Pennsylvania utilities should be the expense savings that are generated by the programs. According to the Commission's CAP Policy Statement:

> In evaluating utility CAPs for ratemaking purposes, the Commission will consider both revenue and expense impacts. Revenue impact considerations include a comparison between the amount of revenue collected from CAP participants prior to and during their enrollment in the CAP. CAP expense impacts include both the expenses associated with operating the CAPs as well as the potential decrease of customary utility operating expenses. Operating expenses include the return requirement on cash working capital for carrying arrearages, the cost of credit and collection activities for dealing with low income negative ability to pay customers and uncollectible accounts expense for writing off bad debt for these customers. When making CAP-related

> expense adjustments and projections, utilities should indicate whether a customer's participation in a CAP produced an immediate reduction in customary utility expenses and a reduction in future customary expenses pertaining to that account.

Pennsylvania PUC, CAP Policy Statement, Section 69.266, 52 Pa. Code §69.266 (Supp. 389, April 2007).

Q. WHAT OFFSETS HAVE YOU INCLUDED IN YOUR CALCULATION OF NET INCREMENTAL CAP EXPENSES?

A. The offsets include four different components: (1) credit and collection offsets; (2) bad debt associated with arrearage forgiveness; (3) cash working capital (CWC) associated with arrearage forgiveness; and (4) cash working capital on a going-forward basis.

A. Credit and Collection Offsets.

Q. PLEASE EXPLAIN THE AVOIDED CREDIT AND COLLECTION EXPENSE YOU HAVE INCLUDED IN YOUR CALCULATIONS.

A. The credit and collection expenses to be considered as a revenue source for CAP are not simply those expenses that might "go away" as a result of OnTrack. Instead, the Company should consider not only the expenses that might go away, but also the expenses that are already embedded in rates that might be redirected toward the costs of supporting the OnTrack program.

To determine the credit and collection expenses already included in rates that might be used to fund OnTrack, I turn to the estimates of administrative cost savings that have been generated by other Pennsylvania utilities. Consider that on a per participant basis, other utilities have found credit and collection savings between $20 and $30 per participant. Given the general consistency of these cost savings estimates, made more robust by the fact that each estimate of savings was made for a different company by a different consultant, and in the absence of data specific to PPL, I have included a credit and collection offset of $25 per CAP participant.

Q. HOW DO YOU PROPOSE TO ADJUST PPL'S COST RECOVERY OF CAP EXPENSES TO TAKE INTO ACCOUNT CREDIT AND COLLECTION SAVINGS?

A. Adjustments designed to take into account redirected credit and collection expenses should begin with the base CAP participation at the year-end of 2006. According to the Company, its OnTrack program had a year-end 2006 participation of 20,721. (OCA-XI-11). I use this as the base for making adjustments. Adjustments should be made to account for the net additions to CAP since that base period. As I have documented in detail above, the most reasonable participation rate projection given the budget estimate proposed by the Company is 22,500. The program will thus experience a net incremental addition of 1,812 participants. With a credit and collection offset of $25 per net addition, there should be a reduction of $45,300 to CAP expenses recovered through the USR.

B. Bad Debt and Arrearage Forgiveness.

Q. HAVE YOU CALCULATED A BAD DEBT OFFSET ATTRIBUTABLE TO THE FORGIVENESS OF PREPROGRAM ARREARS?

A. Yes. The bad debt offset attributable to arrearage forgiveness is designed to ensure that the Company does not collect twice for the same expenses. As with the CAP credits I discuss above, some portion of the arrears subject to forgiveness would, even without CAP, have been written off as bad debt. If the PUC were to allow the Company to collect its entire arrearage forgiveness through the USR, without subtracting those dollars that were already going to be collected as bad debt, the Company would be collecting some of the same dollars twice: once through the bad debt allowance already in rates and then again through the arrearage forgiveness expenses included in the Universal Service Rider.

Q. PLEASE EXPLAIN YOUR BAD DEBT OFFSET CALCULATION ATTRIBUTABLE TO THE ARREARAGE FORGIVENESS COMPONENT OF CAP.

A. BCS reports that PPL had a 2005 bad debt rate of 5.19% for confirmed low-income customers. In the absence of their participation in the CAP program, the Company would have reserved some portion of these revenues as bad debt. Applying the 5.19% bad debt rate to the Company's arrearage forgiveness cost estimate of $4.5 million, there should be a bad debt offset of $233,550. If one applies the 5.19% to my estimated arrearage forgiveness of $3.68 million, there should be a bad debt offset of $165,820.

C. Working Capital and Arrearage Forgiveness.

Q. PLEASE EXPLAIN WHY YOU CALCULATE A WORKING CAPITAL OFFSET ATTRIBUTABLE TO THE FORGIVENESS OF PREPROGRAM ARREARS.

A. Unlike the bad debt offset, the working capital offset attributable to arrearage forgiveness is designed to ensure that the Company does not collect for expenses that have been reduced by the CAP. These are cost savings. Because OnTrack is directed exclusively to payment troubled customers, CAP participants always enter the program with some level of preprogram arrears. (OCA-XI-25, OCA-XI-26). Under CAP, a portion of those preprogram arrears will be forgiven and paid by other customers as those expenses are passed through the Universal Service Rider. As a result, as the arrears are forgiven, the working capital associated with those arrears should be removed from the Company's cost-of-service.

Q. PLEASE EXPLAIN YOUR WORKING CAPITAL OFFSET CALCULATION ATTRIBUTABLE TO THE ARREARAGE FORGIVENESS COMPONENT OF CAP.

A. The pre-program arrears experienced by OnTrack customers are brought into the program. For every month they remain in the program, they will impose one month of working capital on the Company. The Company does not estimate arrearage forgiveness by month. Instead, it assumes that the total annual arrearage forgiveness will reach $4.5 million. (OCA-XI-8, OCA-XI-12; OCA-XI-15).

Q. HOW DOES THIS TRANSLATE INTO A WORKING CAPITAL SAVINGS FOR THE COMPANY?

A. The Company provides the rate at which it forgives arrears on a monthly basis. I use the average rate per month from the years 2005 and 2006. Combining the data above, we know that the total reduction in preprogram arrears is thus the sum of the customer payments and the arrearage credits. My calculation of a working capital savings assumes a constant participation of 22,500. This will understate the working capital savings that the OnTrack program generates.

The forgiveness of arrears will thus generate a decreasing amount of working capital savings throughout the year. The January forgiveness will generate 12 months of avoided working capital; the February forgiveness will generate 11 months of avoided working capital; the March forgiveness will generate 10 months of avoided working capital; and so forth through December, which will generate only one month of avoided working capital. Using an assumed average weighted return of 0.075 (7.5%), grossed up for taxes, there will be a working capital savings for each month of arrearage forgiveness.

If one applies this methodology to the Company's projected arrearage forgiveness, there should be a working capital cost offset of $320,090 as shown in Schedule RDC-6.

D. Working Capital on Going Forward Basis.

Q. HAVE YOU CALCULATED A WORKING CAPITAL OFFSET ON A GOING FORWARD BASIS?

A. Yes. The Company's OnTrack impact evaluation reports that the program results in an improvement in bill payment rate of nearly 20%. According to that evaluation, while low-income customers not in OnTrack make a payment each month roughly 50% of the time, OnTrack participants make payments more than 70% of the time. The OnTrack revenue base in 2006 was $13,026,361. (OCA-XI-33). Given these inputs, the dollars of avoided working capital are calculated in the same way as the avoided working capital associated with preprogram arrears. That calculation is set out in Schedule RDC-7. Schedule RDC-7, page 1 of 2, shows a working capital of $339,856 without CAP. Schedule RDC-7, page 2 of 2 shows a working capital of $203,914 with CAP. The program results in a working capital reduction, on a going-forward basis, of $135,943.

E. Reflecting Offsets in the Universal Service Rider.

Q. HOW DO YOU PROPOSE THAT THE COMPANY REFLECT THE NET INCREMENTAL CAP PROGAM EXPENSES THAT YOU HAVE IDENTIFIED?

A. The offsets to CAP expenses I have identified above can and should be reflected in the determination of the level of the Universal Service Rider. Schedule RDC-8 presents a revised USR calculation incorporating my proposed CAP offsets. Schedule RDC-8 shows that the Universal Service Rider for OnTrack should be 4.74%.

PART 3. UNIVERSAL SERVICE INTER-CLASS COST ALLOCATIONS.

Q. WHAT IS THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY?

A. In this section of my testimony, I respond briefly to the Company's proposal to allocate all universal service costs to the residential class. I have been informed by counsel that the issue of the proper allocation of universal service costs under Section 2804(8) is pending on appeal at this time. I provide the following discussion to highlight the important policy reasons for a broad allocation of these costs.

Universal service costs should be allocated to all customer classes for a variety of reasons. First, Pennsylvania statutes require that universal service costs be collected through a competitively neutral, nonbypassable surcharge. Use of the term "nonbypassable," therefore, incorporates the concept that all customers should help pay for universal service costs.

Second, the Pennsylvania legislature has declared universal service programs to be a "public good." Due to the nature of public goods, all customers receive benefits from public goods and, accordingly, the costs of such goods are spread over all customer classes. Each end user makes a financial contribution to the utility's delivery of public goods. providing that public good.

Third, all customer classes will benefit from the Company's universal service programs. Commercial and industrial customers, as well as small businesses, will gain direct benefits from these programs. Accordingly, since the universal service programs deliver benefits to all customer classes, universal service costs should be allocated to all customer classes.

Fourth, the problem of the inability of some low income customers to pay their entire home energy bills is caused primarily by societal economic conditions that are unrelated to any one rate class. There is no logic to the argument that because the larger societal economic conditions are negatively affecting the ability of some low income residential customers to pay their bills, the problem is somehow caused by the residential class and should therefore be paid for by that class. If the Commission, as a regulatory authority, decides that it is in the public interest to provide home energy services for necessities of life to disadvantaged ratepayers without full payment, then the costs should be borne by all ratepayers who benefit from the companies operating as public utilities.

Q. HOW DOES THE ALLOCATION OF UNIVERSAL SERVICE COSTS RELATE TO THE ORIGINAL DECISION TO MOVE TO A RETAIL CHOICE ELECTRIC INDUSTRY?

A. Different customer classes derive different benefits from Pennsylvania's restructuring statute. The continuation and expansion of Pennsylvania's universal service programs came about in large part as a result of the restructuring of the state's electric power industry. The non-residential customer classes derive the benefits of being able to tap the retail choice market. The residential customer class derives the benefit of being able to tap into universal service programs. In exchange for each class deriving its respective benefits from restructuring, all classes pay for the actions that enabled these benefits to arise. Having received the benefits of the move to retail choice, in other words, the commercial and industrial classes should not now be allowed to avoid their responsibilities under the package of benefits and responsibilities that was agreed to.

Q. IS IT ACCURATE TO ASSERT THAT ONLY RESIDENTIAL CUSTOMERS BENEFIT FROM THE UNIVERSAL SERVICE PROGRAMS?

A. No.The assertion that all universal service costs should be assigned to residential customers because only residential customers (that is low-income customers) benefit from the program proves too much (even accepting solely for purposes of analysis the premise that only low-income customers benefit). If we assume that only low-income customers benefit, and we follow the rule that costs in this case should be allocated only to those who directly benefit, we are brought to the conclusion that universal service costs should be directly assigned pro rata to customers who participate in the universal service programs (such as CRP). Clearly this would be an absurd result, and one that could not logically have been intended by the legislature. In addition, there is no more reason to allocate costs to non-low-income residential customers under this reasoning than there is to allocate them to non-residential customers. Non-low-income residential customers benefit, as they do, exactly and only in the ways and to the extent that non-residential customers benefit.

Q. DOES THE COMPANY USE RATIONALES AKIN TO THOSE YOU IDENTIFY ABOVE IN ANY OTHER COST ALLOCATION DECISION?

A. Yes. PPL proposes to implement a Sustainable Development Program (SDP). The proposed SDP would provide economic development funding for industrial locations, downtown development, and commercial marketing. (See, Dahl Direct, at 19 – 25). Residential customers are not eligible to receive funding through the SDP and cannot access the SDP. Despite this, Company witness Dahl states that "the Company proposes to reflect the costs as an expense in base rates, which would be allocated to all customer classes." (Dahl Direct, at 20). The Company justifies this cost allocation recommendation on the basis that the Sustainable Development Program provides benefits "to many." (Dahl Direct, at 24).

Allocating SDP costs to all customer classes, including the residential customer class, while allocating universal service costs only to the residential class, cannot be reconciled. Just as non-residential customers cannot access the universal service programs, residential customers cannot access the Sustainable Development Program. Just as the SDP delivers broad benefits to all customers, and all customer classes, so, too, do the universal service programs deliver benefits to all customers and all customer classes. Applying the same cost allocation principles and rationales to both programs is reasonable. To be consistent with its allocation of SDP expenses, the Company should allocate universal service costs to all customer classes as well.

PART 4. CEILING ON CAP CREDITS.

Q. WHAT IS THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY?

A. In this section of my testimony, I consider the reasonableness of the Company's proposed "stay-out" provision directed toward OnTrack participants who exceed the maximum CAP credits. Company witness Dahl states that the Company proposes to "remove customers from CAP when they exceed their annual CAP Credits limit and evaluate their re-enrollment in the program at the time of their normal re-certification." (Dahl Direct, at 15). Moreover, the Universal Service Plan provides that the Company proposes to "implement a stay-out provision for customers who exceed their CAP benefit limits. These customers will remain ineligible until their next OnTrack anniversary date." (Exhibit TRD-1, OnTrack section, page 15; see also, OCA-XII-14).

Q. WHAT DO YOU RECOMMEND?

A. I recommend that the Company's proposal to impose a ceiling on CAP credits be made subject to two conditions. First, any customer that is subject to the CAP credit ceiling should be given the opportunity to demonstrate that his or her usage is beyond the ability of the household to control. Second, any customer that is subject to the CAP credit ceiling should be given first priority in the delivery of any energy efficiency investments through the Company's Low-Income Usage Reduction Program (LIURP).

Q. PLEASE EXPLAIN THE BASIS FOR YOUR CONCERNS WITH THE CAP CREDIT CEILING AS PROPOSED.

A. A ceiling on CAP credits should only be imposed as a measure to help control CAP costs. OnTrack participants, in other words, should not exercise customer choices that result in unreasonably high usage levels because of the limits that the program places on their payment responsibilities. When, however, the level of CAP credits is not within the ability of a customer to control, the CAP credit ceiling does not affect what energy consumption choices an OnTrack participant makes. In these circumstances, rather than helping to control consumption, a CAP credit ceiling only serves to make energy bills unaffordable.

In light of this overview, there are four reasons why I have concern about the Company's proposed stay-out provision for exceeding maximum CAP credits in the absence of the two conditions I propose above.

Q. PLEASE EXPLAIN YOUR FIRST CONCERN WITH IMPLEMENTING A CEILING ON CAP CREDITS WITHOUT ALSO IMPLEMENTING YOUR PROPOSED CONDITIONS.

A. First, the maximum CAP credits were adopted in the Revisions to the CAP Policy Statement *issued in April 1999. Electric prices have remained reasonably stable in Pennsylvania since* that time due to the imposition of price caps as part of the move to a retail choice electric industry in Pennsylvania. Price caps in Pennsylvania, however, are due to expire soon. At a minimum, the imposition of maximum CAP credits in an electric utility CAP should be postponed until after all stakeholders can determine what maximum would be reasonable in the post-price cap environment. Without such a postponement, imposing the maximum CAP credit becomes punitive rather than simply being a program cost control measure.

Q. PLEASE EXPLAIN YOUR SECOND CONCERN WITH IMPLEMENTING A CEILING ON CAP CREDITS WITHOUT ALSO IMPLEMENTING YOUR PROPOSED CONDITIONS.

A. Second, the maximum CAP credit does not apply irrespective of the situation of the household. Instead, the CAP Policy Statement provides that customers should be exempted from the maximum CAP credit when consumption is beyond the ability of the household to control. (§69.265(3)(vi)). There is compelling evidence that CAP credits are often not within the ability of the household to control. U.S. Department of Energy (DOE) data documents that factors influencing high home energy usage are largely related to income. Household energy consumption is, in other words, not a "choice" to use energy; nor is the control of electricity usage merely a "choice" to make different consumption decisions. Households that live in older and less inefficient homes, that own older and less efficient home heating systems, and that own older and less efficient home appliances (such as refrigerators) tend to be the lowest income households. Income and these less efficient energy uses are unquestionably associated (as income goes down, the prevalence of less efficient homes, heating systems and appliances goes up). Under such circumstances, imposing the maximum CAP credit becomes punitive rather than simply being a program cost control measure.

The problem with this lack of control over electricity consumption is exacerbated when the OnTrack participant is a tenant. The Company reports that had its proposed $1,800 maximum CAP credit been in effect in 2006, it would have removed 2,570 OnTrack heating customers due to "exceeding the $1,800 limit on CAP credits." (OCA-XI-20). The Company stated that 1,567 homeowners and 1,003 renters would have been removed from CAP due to exceeding an $1,800 CAP credit ceiling. Similarly, 2,968 OnTrack participants would have been removed from CAP in 2005 for exceeding the $1,800 CAP credit ceiling, had such a ceiling been in effect for 2005, (OCA-XI-20), of which 1,185 would have been tenants. OnTrack participants who are tenants, even if they had the financial wherewithal to invest in energy efficiency improvements, would not exercise the authority over their living conditions to invest in energy reduction strategies. A tenant, in other words, does not exercise dominion over his or her own rental unit such that he or she could decide to improve weatherization or upgrade the efficiency of heating systems, refrigerators, or other major electric-consuming appliances.

Q. PLEASE EXPLAIN YOUR THIRD CONCERN WITH IMPLEMENTING A CEILING ON CAP CREDITS WITHOUT ALSO IMPLEMENTING YOUR PROPOSED CONDITIONS.

A. Third, a CAP credit is as much a function of income as it is of consumption. An OnTrack participant with income at or below 50% of Poverty Level is, by definition, more likely to have a CAP credit that exceeds the CAP credit ceiling than a similarly situated OnTrack participant at a higher income level. The OnTrack participant with income at a lower Poverty Level will pay a smaller CAP payment toward his or her bill than the higher income participant, thus leaving a higher CAP credit. The Company could not provide a breakdown of CAP credits by Federal Poverty Level for 2006. (OCA-XI-18; OCA-XI-19). Nor could the Company provide a breakdown of the different "payment options" by Federal Poverty Level. (OCA-XII-6). In each of the three full years for which data is available (2004, 2005 and 2006), however, the Company noted that by far the highest percentage of customers who would have reached the $1,800 limit for CAP credits would have been customers paying under the percentage of income payment option.[1]

Q. PLEASE EXPLAIN YOUR FINAL CONCERN WITH IMPLEMENTING A CEILING ON CAP CREDITS WITHOUT ALSO IMPLEMENTING YOUR PROPOSED CONDITIONS.

A. Finally, PPL's proposal regarding a ceiling on CAP credits would discourage PPL's OnTrack customers from making their monthly customer payment. Under the OnTrack program, a CAP participant receives his or her CAP credit only upon making the customer payment toward the monthly bill. One reason the Company can experience an increase in its CAP credits granted is because of an increase in the percentage of current CAP customers. Increasing the percentage of current CAP customers is a good phenomenon, not an objectionable one. The Commission should not adopt any proposal that might impede reaching that objective.

Q. WOULD YOUR PROPOSAL REQUIRE IMPLEMENTATION WORK SUBSEQUENT TO A DECISION IN THIS RATE PROCEEDING?

A. Yes. I would recommend that the Company adopt objective standards to apply in making any decision about whether a household's energy consumption is beyond the ability of the customer to control. The Company should be able to provide clear notice to the customer of those circumstances under which the ceiling on CAP credits would *not* be enforced.

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[1] The company offers four payment options: (1) a minimum payment; (2) a payment based on a percentage of the bill; (3) a percentage-of-income option; or (4) an option based on the annualized payment actually made in the preceding year. The Company also allows an intake agency to select an option not otherwise provided for ("agency selected" option).

Circumstances involving unweatherized homes of a particular age, heating systems of a particular age, and/or refrigerators of a particular age would all be compelling evidence that electric consumption is beyond the ability of the customer to control. OCA would be willing to work with the Company to develop these objective standards.

Q. DO YOUR PROPOSED CONDITIONS RENDER A CEILING ON CAP CREDITS INEFFECTIVE?

A. No. Indeed, my proposal is entirely consistent with the PUC's previous policy that low-income customers should not be charged for electricity billing that is not within their ability to control. My proposal simply requires the Company to operationalize the provisions of Title 52, Section 69.265(vi)(c), of the Commission regulations, which provides for the exemption of households from maximum CAP credit ceilings in the event that the energy consumption is beyond the ability of the household to control.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

Schedule RDC-1

Excluded Budgeted Administrative Expenditures (OnTrack):
2007

Budget Item	Description	Expenditures
11000	Wages	$977,615
13000	Employee expenses	$7,200
14000	Vehicle and equipment use	$3,171
24000	Stores issues	$5,407
33000	Services	$30,000
34000	Postage, Mail/Package Delivery	$1,320
37000	Advertising	$1,500
49000	Miscellaneous	$3,000
Total		$1,029,213

SOURCE: OCA-35 (2007).

Schedule RDC-2

Average Annual OnTrack CAP Credit (2006)

2006	TOTAL /a/	No. of Participants /b/	Average CAP credit /c/
Jan	$1,383,800.12	13,600	$102
Feb	$986,177.84	13,821	$71
Mar	$1,338,276.65	15,082	$89
Apr	$745,272.77	15,876	$47
May	$544,986.70	16,678	$33
Jun	$610,504.39	17,529	$35
Jul	$819,109.71	18,567	$44
Aug	$1,114,647.98	19,545	$57
Sep	$757,670.27	20,264	$37
Oct	$647,791.24	20,818	$31
Nov	$1,003,861.97	20,957	$48
Dec	$1,287,323.55	20,721	$62
Average monthly participants/total annual CAP credit		17,788	$656
LIHEAP offset		$1,873,809 /d/	($105)
Net CAP credit (total annual CAP credit – LIHEAP offset)			$551

SOURCE:

/a/ OCA-XI-33.
/b/ OCA-XI-11.
/c/ Column 2 / Column 3.
/d/ OCA-XI-10.

Schedule RDC-3

OnTrack Customers Actually Receiving Arrearage Forgiveness compared to On Track Customers Eligible to Receive Arrearage Forgiveness (2006)

	Eligible to Receive Forgiveness	Received	Percentage
Jan	624	395	63%
Feb	590	378	64%
Mar	578	369	64%
Apr	597	389	65%
May	615	407	66%
Jun	629	429	68%
Jul	655	460	70%
Aug	702	503	72%
Sep	721	519	72%
Oct	700	545	78%
Nov	698	554	79%
Dec	654	546	83%
Total	7,763	5,494	71%

Schedule RDC-4

Adjusting CAP Credit Budget for Implementation of $1,800 CAP Credit Ceiling

Number of estimated OnTrack participants	22,500
Percentage of OnTrack participants to be removed because of excess CAP credits	12.5%
Number of OnTrack participants to be removed because of excess CAP credits	2,812
Number of removed participants with credits between $1,800 and $2,100	1,687
Number of removed participants with credits over $2,100	1,125
CAP credits removed from budget for participants with credits between $1,800 and $2,100	$253,125
CAP credits removed from budget for participants with credits over $2,100	$562,500
Total CAP credits removed from budget	$815,625

Schedule RDC-5

PPL Universal Service Rider Given Colton Adjustments to OnTrack Expense Recovery	
CAP credits reduced for non-timely payment	$3,741,000
CAP credits reduced to reflect ceiling on credits	$815,625
CAP credits reduced to prevent double recovery	$68,092
Arrearage forgiveness reduced to reflect non-timely bill payment	$1,305,000
Administrative expenses reduced to reflect non-CAP expenses	$1,029,213
Total OnTrack budget reduction	$6,958,930
Original Universal Service budget	$27,896,000
Adjusted Universal Service budget	$20,937,070
Total distribution revenue	$427,036,566
Universal Service Rider	4.90%

Schedule RDC-6

Estimate of Working Capital Savings Derived from Arrearage Forgiveness Given PPL Calculation of Arrearage Forgiveness

	Days in Month	Arrears Forgiveness	Arrears Reduction	Weighted Return	Taxes	Weighted Return (GUFT)	Daily Return	Days Avoided	Revenue Days Avoided	Avoided Return
January	31	$303,518	$416,018	7.5%	40.0%	10.5%	0.02877%	365	151,846,570	$43,682
February	28	$293,685	$406,185	7.5%	40.0%	10.5%	0.02877%	334	135,665,790	$39,027
March	31	$343,160	$455,660	7.5%	40.0%	10.5%	0.02877%	306	139,431,960	$40,111
April	30	$299,519	$412,019	7.5%	40.0%	10.5%	0.02877%	275	113,305,225	$32,595
May	31	$352,497	$464,997	7.5%	40.0%	10.5%	0.02877%	245	113,924,265	$32,773
June	30	$405,145	$517,645	7.5%	40.0%	10.5%	0.02877%	214	110,776,030	$31,867
July	31	$395,658	$508,158	7.5%	40.0%	10.5%	0.02877%	184	93,501,072	$26,898
August	31	$463,904	$576,404	7.5%	40.0%	10.5%	0.02877%	153	88,189,812	$25,370
September	30	$412,828	$525,328	7.5%	40.0%	10.5%	0.02877%	122	64,090,016	$18,437
October	31	$472,172	$584,672	7.5%	40.0%	10.5%	0.02877%	92	53,789,824	$15,474
November	30	$477,588	$590,088	7.5%	40.0%	10.5%	0.02877%	61	35,995,368	$10,355
December	31	$280,327	$392,827	7.5%	40.0%	10.5%	0.02877%	31	12,177,637	$3,503
Total	365	$4,500,000	$5,850,000							$320,090

Schedule RDC-7
(page 1 of 2)

Working Capital for Unpaid Current Bills without CAP

	Days in Month	Billed Revenue	Percent Missed Pyt	$s Missed Payments	Weighted Return	Taxes	Weighted Return (GUFT)	Daily Return	Days of Wkg Cap	Revenue Days of Wkg Cap	Wkg Cap Return
January	31	$861,975	50.00%	$430,988	7.5%	40.0%	10.5%	0.02877%	365	157,310,620	$45,254
February	28	$823,400	50.00%	$411,700	7.5%	40.0%	10.5%	0.02877%	334	137,507,800	$39,557
March	31	$841,232	50.00%	$420,616	7.5%	40.0%	10.5%	0.02877%	306	128,708,496	$37,026
April	30	$929,670	50.00%	$464,835	7.5%	40.0%	10.5%	0.02877%	275	127,829,625	$36,773
May	31	$1,002,443	50.00%	$501,222	7.5%	40.0%	10.5%	0.02877%	245	122,799,390	$35,326
June	30	$1,068,176	50.00%	$534,088	7.5%	40.0%	10.5%	0.02877%	214	114,294,832	$32,879
July	31	$1,134,859	50.00%	$567,430	7.5%	40.0%	10.5%	0.02877%	184	104,407,120	$30,035
August	31	$1,208,908	50.00%	$604,454	7.5%	40.0%	10.5%	0.02877%	153	92,481,462	$26,604
September	30	$1,258,901	50.00%	$629,451	7.5%	40.0%	10.5%	0.02877%	122	76,793,022	$22,091
October	31	$1,287,790	50.00%	$643,895	7.5%	40.0%	10.5%	0.02877%	92	59,238,340	$17,041
November	30	$1,306,330	50.00%	$653,165	7.5%	40.0%	10.5%	0.02877%	61	39,843,065	$11,462
December	31	$1,302,676	50.00%	$651,338	7.5%	40.0%	10.5%	0.02877%	31	20,191,478	$5,809
Total	365										$339,856

Schedule RDC-7
(page 2 of 2)

Working Capital for Unpaid Current Bills with CAP

	Days in Month	Billed Revenue	Percent Missed Pyt	$s Missed Payments	Weighted Return	Taxes	Weighted Return (GUFT)	Daily Return	Days of Wkg Cap	Revenue Days of Wkg Cap	Wkg Cap Return
January	31	$861,975	30.00%	$258,593	7.5%	40.0%	10.5%	0.02877%	365	94,386,445	$27,152
February	28	$823,400	30.00%	$247,020	7.5%	40.0%	10.5%	0.02877%	334	82,504,680	$23,734
March	31	$841,232	30.00%	$252,370	7.5%	40.0%	10.5%	0.02877%	306	77,225,220	$22,215
April	30	$929,670	30.00%	$278,901	7.5%	40.0%	10.5%	0.02877%	275	76,697,775	$22,064
May	31	$1,002,443	30.00%	$300,733	7.5%	40.0%	10.5%	0.02877%	245	73,679,585	$21,195
June	30	$1,068,176	30.00%	$320,453	7.5%	40.0%	10.5%	0.02877%	214	68,576,942	$19,728
July	31	$1,134,859	30.00%	$340,458	7.5%	40.0%	10.5%	0.02877%	184	62,644,272	$18,021
August	31	$1,208,908	30.00%	$362,672	7.5%	40.0%	10.5%	0.02877%	153	55,488,816	$15,963
September	30	$1,258,901	30.00%	$377,670	7.5%	40.0%	10.5%	0.02877%	122	46,075,740	$13,255
October	31	$1,287,790	30.00%	$386,337	7.5%	40.0%	10.5%	0.02877%	92	35,543,004	$10,225
November	30	$1,306,330	30.00%	$391,899	7.5%	40.0%	10.5%	0.02877%	61	23,905,839	$6,877
December	31	$1,302,676	30.00%	$390,803	7.5%	40.0%	10.5%	0.02877%	31	12,114,893	$3,485
Total	365										$203,914

Schedule RDC-8

PPL Universal Service Rider Given Colton Adjustments to OnTrack Expense Recovery

Adjusted Universal Service budget (as per Schedule RDC-5)	$20,937,070
Credit and collection offsets	$70,300
Bad debt savings associated with arrearage forgiveness	$165,820
Working capital savings associated with arrearage forgiveness	$320,090
Working capital savings associated with CAP bill payment	$135,943
Universal Service budget adjusted for offsets	$20,244,917
Total distribution revenue	$427,036,566
Universal Service Rider	4.74%

ATTACHMENT A

ROGER D. COLTON

BUSINESS ADDRESS:

Fisher Sheehan & Colton
Public Finance and General Economics
34 Warwick Road, Belmont, MA 02478
617-484-0597 (voice) *** 617-484-0594 (fax)
roger@fsconline.com (e-mail)
http://www.fsconline.com (www address)

EDUCATION:

J.D. (Order of the Coif), University of Florida, 1981

M.A. (Economics), McGregor School, Antioch University (1993)

B.A., Iowa State University (1975)

PROFESSIONAL EXPERIENCE:

Fisher, Sheehan and Colton, Public Finance and General Economics: 1985 - present.

As a co-founder of this economics consulting partnership, Colton provides services in a variety of areas, including: regulatory economics, poverty law and economics, public benefits, fair housing, community development, energy efficiency, utility law and economics (energy, telecommunications, water/sewer), government budgeting, and planning and zoning.

Colton has testified in state and federal courts in the United States and Canada, as well as before regulatory and legislative bodies in more than three dozen states. He is particularly noted for creative program design and implementation within tight budget constraints.

National Consumer Law Center (NCLC): 1986 - 1994

As a staff attorney with NCLC, Colton worked on low-income energy and utility issues. He pioneered cost-justifications for low-income affordable energy rates, as well as developing models to quantify the non-energy benefits (*e.g.*, reduced credit and collection costs, reduced working capital) of low-income energy efficiency. He designed and implemented low-income affordable rate and fuel assistance programs across the country. Colton was charged with developing new practical and theoretical underpinnings for solutions to low-income energy problems.

Community Action Research Group (CARG): 1981 - 1985

As staff attorney for this non-profit research and consulting organization, Colton worked primarily on energy and utility issues. He provided legal representation to low-income persons on public utility issues; provided legal and technical assistance to consumer and labor organizations; and provided legal and technical assistance to a variety of state and local governments nationwide on natural gas, electric, and telecommunications issues. He routinely appeared as an expert witness before regulatory agencies and legislative committees regarding energy and telecommunications issues.

PROFESSIONAL AFFILIATIONS:

Chair: Board of Directors, Belmont Housing Trust
Member: Advisory Board: Fair Housing Center of Greater Boston.
Past Member: Aggregation Advisory committee, New York State Energy Research and Development Authority.
Past Member: Board of Directors, Vermont Energy Investment Corporation.
Past Member: Board of Directors, National Fuel Funds Network
Past Member: National Advisory Committee, U.S. Department of Health and Human Services, Administration for Children and Families, Performance Goals for Low-Income Home Energy Assistance.
Past Member: Advisory Board: Low-Income Aggregation, New York State Energy Research and Development Authority.
Past Member: Editorial Advisory Board, International Library, ***Public Utility Law Anthology***.
Past Member: ASHRAE Guidelines Committee, GPC-8, *Energy Cost Allocation of Comfort HVAC Systems for Multiple Occupancy Buildings*
Past Member: National Advisory Committee, U.S. Department of Housing and Urban Development, Calculation of Utility Allowances for Public Housing.
Past Member: National Advisory Board: Energy Financing Alternatives for Subsidized Housing, New York State Energy Research and Development Authority.

PROFESSIONAL ASSOCIATIONS:

National Association of Housing and Redevelopment Officials (NAHRO)
Association for Enterprise Opportunity
Iowa State Bar Association
Association for Institutional Thought
Association for Evolutionary Economics
Society for the Study of Social Problems
International Society for Policy Studies
Association for Social Economics

AWARDS

- William F. Willier Award (distinguished service) (1991). National Consumer Law Center, Boston (MA).
- NLIEC Career Achievement Award (1998). National Low-Income Energy Consortium, New Orleans (LA).
- Sister Pat Kelley Award (distinguished service) (2001). National Fuel Funds Network, Cincinnati (OH).
- Governor's Volunteer Award (Iowa) (2001).

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COLTON TESTIMONY EXPERIENCE

1988 - PRESENT

CASE NAME	ROLE	CLIENT NAME	TOPIC	JURIS.	DATE
I/M/O Philadelphia Gas Works	Witness	Office of Consumer Advocate	Low-income and residential collections	Pennsylvania	07
I/M/O Equitable Gas Company	*Witness*	*Office of Consumer Advocate*	Low-income program	Pennsylvania	07
I/M/O Section 11 Proceeding, Energy Restructuring	Witness	Office of Peoples Counsel	Low-income energy needs and responses	Maryland	06
I/M/O Public Service Company of New Mexico	Witness	Community Action of New Mexico	Low-income programs	New Mexico	06
I/M/O Petition of Citizens Gas/NIPSCO/Vectren for Universal Service Programs	Witness	Citizens Gas & Coke Utility/Northern Indiana Public Service/Vectren Energy Delivery	Low-income program design	Indiana	06
I/M/O Public Service Co. of North Carolina	*Witness*	*North Carolina Attorney General/Dept. of Justice*	Low-income energy usage	North Carolina	06
I/M/O Electric Assistance Program	Witness	New Hampshire Legal Assistance	Electric low-income program design	Vermont	06
I/M/O Verizon Petition for *Alternative Regulation*	Witness	New Hampshire Legal Assistance	Basic local telephone service	Vermont	06
I/M/O Pennsylvania Electric Co/Metropolitan Edison Co.	Witness	Office of Consumer Advocate	Universal service cost recovery	Pennsylvania	06
I/M/O Duquesne Light Company	Witness	Office of Consumer Advocates	Universal service cost recovery	Pennsylvania	06
I/M/O Natural Gas DSM Planning	Witness	Low-Income Energy Network	Low-income DSM program.	Ontario	06
I/M/O Union Gas Co.	Witness	Action Centre for Tenants Ontario (ACTO)	Low-income program design	Ontario	06
I/M/O Public Service of New Mexico merchant plant	Witness	Community Action New Mexico	Low-income energy usage	New Mexico	06
I/M/O Customer Assistance Program design and cost recovery	Witness	Office of Consumer Advocate	Low-income program design	Pennsylvania	06
I/M/O NIPSCO Proposal to Extend Winter Warmth Program	Witness	Northern Indiana Public Service Company	Low-income energy program evaluation	Indiana	05
I/M/O Piedmont Natural Gas	Witness	North Carolina Attorney General/Dept. of Justice	Low-income energy usage	North Carolina	05
I/M/O PSEG merger with Exelon Corp.	Witness	Division of Ratepayer Advocate	Low-income issues	New Jersey	05
Re. Philadelphia Water Department	Witness	Public Advocate	Water collection factors	Philadelphia	05
I/M/O statewide natural gas universal service program	Witness	*New Hampshire Legal Assistance*	Universal service	New Hampshire	05
I/M/O Sub-metering requirements for residential rental properties	Witness	Tenants Advocacy Centre of Ontario	Sub-metering consumer protections	Ontario	05
I/M/O National Fuel Gas Distribution Corp.	Witness	Office of Consumer Advocate	Universal service	Pennsylvania	05

CASE NAME	ROLE	CLIENT NAME	TOPIC	JURIS.	DATE
I/M/O Nova Scotia Power, Inc.	Witness	Dalhousie Legal Aid Service	Universal service	Nova Scotia	04
I/M/O Lifeline Telephone Service	Witness	National Ass'n State Consumer Advocates (NASUCA)	Lifeline rate eligibility	FCC	04
Mackay v. Verizon North	Witness	*Office of Consumer Advocate*	*Lifeline rates—vertical services*	Pennsylvania	04
I/M/O Philadelphia Gas Works	Witness	Office of Consumer Advocate	Credit and collections	Pennsylvania	04
I/M/O Citizens Gas & Coke/Vectren	Witness	Citizens Action Coalition of Indiana	Universal service	Indiana	04
I/M/O PPL Electric Corporation	Witness	Office of Consumer Advocate	Universal service	Pennsylvania	04
I/M/O Consumers New Jersey Water Company	Witness	Division of Ratepayer Advocate	Low-income water rate	New Jersey	04
I/M/O Washington Gas Light Company	Witness	Office of Peoples Counsel	Low-income gas rate	Maryland	04
I/M/O Washington Gas Light Company	Witness	Office of Peoples Counsel	Low-income gas rate	Maryland	03
Golden v. City of Columbus	Witness	Helen Golden	ECOA disparate impacts	Ohio	02
Huegel v. City of Easton	Witness	Phyllis Huegel	Credit and collection	Pennsylvania	02
I/M/O Universal Service Fund	Witness	Public Utility Commission staff	Universal service funding	New Hampshire	02
I/M/O Philadelphia Gas Works	Witness	Office of Consumer Advocate	Universal service	Pennsylvania	02
I/M/O Washington Gas Light Company	Witness	Office of Peoples Counsel	Rate design	Maryland	02
I/M/O Consumers Illinois Water Company	Witness	Illinois Citizens Utility Board	Credit and collection	Illinois	02
I/M/O Public Service Electric & Gas Rates	Witness	Division of Ratepayer Advocate	Universal service	New Jersey	01
I/M/O Pennsylvania-American Water Company	Witness	Office of Consumer Advocate	Low-income rates and water conservation	Pennsylvania	01
I/M/O Louisville Gas & Electric Prepayment Meters	Witness	Kentucky Community Action Association	Low-income energy	Kentucky	01
I/M/O NICOR Budget Billing Plan Interest Charge	Witness	Cook County State's Attorney	Rate Design	*Illinois*	01
I/M/O Rules Re. Payment Plans for High Natural Gas Prices	Witness	Cook County State's Attorney	Budget Billing Plans	Illinois	01
I/M/O Philadelphia Water Department	Witness	Office of Public Advocate	Credit and collections	Philadelphia	01
I/M/O Missouri Gas Energy	Witness	Office of Peoples Counsel	Low-income rate relief	Missouri	01
I/M/O Bell Atlantic–New Jersey Alternative Regulation	Witness	Division of Ratepayer Advocate	Telecommunications universal service	New Jersey	01

CASE NAME	ROLE	CLIENT NAME	TOPIC	JURIS.	DATE
I/M/O T.W. Phillips Gas and Oil Co.	Witness	Office of Consumer Advocate	Ratemaking of universal service costs.	Pennsylvania	00
I/M/O Peoples Natural Gas Company	*Witness*	*Office of Consumer Advocate*	Ratemaking of universal service costs.	Pennsylvania	00
I/M/O UGI Gas Company	Witness	Office of Consumer Advocate	Ratemaking of universal service costs.	Pennsylvania	00
I/M/O PFG Gas Company	Witness	Office of Consumer Advocate	Ratemaking of universal service costs.	Pennsylvania	00
Armstrong v. Gallia Metropolitan Housing Authority	Witness	Equal Justice Foundation	Public housing utility allowances	Ohio	00
I/M/O Bell Atlantic--New Jersey Alternative Regulation	Witness	Division of Ratepayer Advocate	Telecommunications universal service	New Jersey	00
I/M/O Universal Service Fund for Gas and Electric Utilities	Witness	Division of Ratepayer Advocate	Design and funding of low-income programs	New Jersey	00
I/M/O Consolidated Edison Merger with Northeast Utilities	Witness	Save Our Homes Organization	Merger impacts on low-income	New Hampshire	00
I/M/O UtiliCorp Merger with St. Joseph Light & Power	Witness	Missouri Dept. of Natural Resources	Merger impacts on low-income	Missouri	00
I/M/O UtiliCorp Merger with Empire District Electric	Witness	Missouri Dept. of Natural Resources	Merger impacts on low-income	Missouri	00
I/M/O PacifiCorp	Witness	The Opportunity Council	Low-income energy affordability	Washington	00
I/M/O Public Service Co. of Colorado	Witness	Colorado Energy Assistance Foundation	Natural gas rate design	Colorado	00
I/M/O Avista Energy Corp.	Witness	Spokane Neighborhood Action Program	Low-income energy affordability	Washington	00
I/M/O TW Phillips Energy Co.	Witness	Office of Consumer Advocate	Universal service	Pennsylvania	00
I/M/O PECO Energy Company	Witness	Office of Consumer Advocate	Universal service	Pennsylvania	00
I/M/O National Fuel Gas Distribution Corp.	Witness	Office of Consumer Advocate	Universal service	Pennsylvania	00
I/M/O PFG Gas Company	Witness	Office of Consumer Advocate	Universal service	Pennsylvania	00
I/M/O UGI Energy Company	Witness	*Office of Consumer Advocate*	Universal service	Pennsylvania	00
Re. PSCO/NSP Merger	Witness	Colorado Energy Assistance Foundation	Merger impacts on low-income	Colorado	99 - 00
I/M/O Peoples Gas Company	Witness	Office of Consumer Advocate	Universal service	Pennsylvania	99
I/M/O Columbia Gas Company	Witness	Office of Consumer Advocate	Universal service	Pennsylvania	99
I/M/O PG Energy Company	Witness	Office of Consumer Advocate	Universal service	Pennsylvania	99
I/M/O Equitable Gas Company	Witness	Office of Consumer Advocate	Universal service	Pennsylvania	99
Allerruzzo v. Klarchek	Witness	Barlow Allerruzzo	Mobile home fees and sales	Illinois	99
I/M/O Restructuring New Jersey's Natural Gas Industry	Witness	Division of Ratepayer Advocate	Universal service	Pennsylvania	99

CASE NAME	ROLE	CLIENT NAME	TOPIC	JURIS.	DATE
I/M/O Bell Atlantic Local Competition	Witness	Public Utility Law Project	Lifeline telecommunications rates	New Jersey	99
I/M/O Merger Application for SBC and Ameritech Ohio	Witness	Edgemont Neighborhood Association	Merger impacts on low-income consumers	Ohio	98 - 99
Davis v. American General Finnce	Witness	Thomas Davis	Damages in "loan flipping" case	Ohio	98 - 99
Griffin v. Associates Financial Service Corp.	Witness	Earlie Griffin	Damages in "loan flipping" case	Ohio	98 - 99
I/M/O Baltimore Gas and Electric Restructuring Plan	Witness	Maryland Office of Peoples Counsel	Consumer protection/basic generation service	Maryland	98 - 99
I/M/O Delmarva Power and Light Restructuring Plan	Witness	Maryland Office of Peoples Counsel	Consumer protection/basic generation service	Maryland	98 - 99
I/M/O Potomac Electric Power Co. Restructuring Plan	Witness	Maryland Office of Peoples Counsel	Consumer protection/basic generation service	Maryland	98 - 99
I/M/O Potomac Edison Restructuring Plan	Witness	Maryland Office of Peoples Counsel	Consumer protection/basic generation service	Maryland	98 - 99
VMHOA v. LaPierre	Witness	Vermont Mobile Home Owners Association	Mobile home tying	Vermont	98
Re. Restructuring Plan of Virginia Electric Power	Witness	VMH Energy Services, Inc.	Consumer protection/basic generation service	Virginia	98
Mackey v. Spring Lake Mobile Home Estates	Witness	Timothy Mackey	Mobile home fees	State ct: Illinois	98
Re. Restructuring Plan of Atlantic City Electric	Witness	New Jersey Division of Ratepayer Advocate	Low-income issues	New Jersey	97-98
Re. Restructuring Plan of Jersey Central Power & Light	Witness	New Jersey Division of Ratepayer Advocate	Low-income issues	New Jersey	97-98
Re. Restructuring Plan of Public Service Electric & Gas	Witness	New Jersey Division of Ratepayer Advocate	Low-income issues	New Jersey	97-98
Re. Restructuring Plan of Rockland Electric	Witness	New Jersey Division of Ratepayer Advocate	Low-income issues	New Jersey	97-98
Appleby v. Metropolitan Dade County Housing Agency	Witness	Legal Services of Greater Miami	HUD utility allowances	Fed. court: So. Florida	97 - 98
Re. Restructuring Plan of PECO Energy Company	Witness	Energy Coordinating Agency of Philadelphia	Universal service	Pennsylvania	97
Re. Atlantic City Electric Merger	Witness	New Jersey Division of Ratepayer Advocate	Low-income issues	New Jersey	97
Re. IES Industries Merger	Witness	Iowa Community Action Association	Low-income issues	Iowa	97
Re. New Hampshire Electric Restructuring	Witness	NH Comm. Action Ass'n	Wires charge	New Hampshire	97
Re. Natural Gas Competition in Wisconsin	Witness	Wisconsin Community Action Association	Universal service	Wisconsin	96
Re. Baltimore Gas and Electric Merger	Witness	Maryland Office of Peoples Counsel	Low-income issues	Maryland	96
Re. Northern States Power Merger	Witness	Energy Cents Coalition	Low-income issues	Minnesota	96
Re. Public Service Co. of Colorado Merger	Witness	Colorado Energy Assistance Foundation	Low-income issues	Colorado	96
Re. Massachusetts Restructuring Regulations	Witness	Fisher, Sheehan & Colton	Low-income issues/energy efficiency	Massachusetts	96

CASE NAME	ROLE	CLIENT NAME	TOPIC	JURIS.	DATE
Re. FERC Merger Guidelines	Witness	National Coalition of Low-Income Groups	Low-income interests in mergers	Washington D.C.	96
Re. Joseph Keliikuli III	Witness	Joseph Keliikuli III	Damages from lack of homestead	Honolulu	96
Re. Theresa Mahaulu	Witness	Theresa Mahaulu	Damages from lack of homestead	Honolulu	95
Re. Joseph Ching, Sr.	Witness	Re. Joseph Ching, Sr.	Damages from lack of homestead	Honolulu	95
Joseph Keaulana, Jr.	Witness	Joseph Keaulana, Jr.	*Damages from lack of homestead*	Honolulu	95
Re. Utility Allowances for Section 8 Housing	Witness	National Coalition of Low-Income Groups	Fair Market Rent Setting	Washington D.C.	95
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OCA STATEMENT NO. 4S
AUG 1 3 2007

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

PPL ELECTRIC UTILITIES CORPORATION	))	DOCKET NO. R-00072155

DOCUMENT FOLDER

SURREBUTTAL TESTIMONY OF

ROGER COLTON

TOPIC ADDRESSED:
UNIVERSAL SERVICE PROGRAM
DESIGN AND RATE RECOVERY

RECEIVED
AUG 1 4 2007
PA PUBLIC UTILITY COMMISSION
SECRETARY'S BUREAU

ON BEHALF OF THE

OFFICE OF CONSUMER ADVOCATE

AUGUST 2007

Q. PLEASE STATE YOUR NAME AND ADDRESS.

A. My name is Roger Colton. My address is Fisher, Sheehan & Colton, Public Finance and General Economics, 34 Warwick Road, Belmont, MA 02478.

Q. ARE YOU THE SAME ROGER COLTON WHO HAS PREVIOUSLY FILED DIRECT TESTIMONY ON BEHALF OF THE OFFICE OF CONSUMER ADVOCATE IN THIS PROCEEDING?

A. Yes.

Q. WHAT IS THE PURPOSE OF YOUR SURREBUTTAL TESTIMONY TODAY?

A. My surrebuttal testimony will respond to the rebuttal testimony of three witnesses: (1) Company witness Timothy Dahl; (2) PPLICA witness Stephen Baron; and (3) OSBA witness Robert Knecht.

PART 1. RESPONSE TO PPL WITNESS TIMOTHY DAHL.

Q. PLEASE IDENTIFY THE TESTIMONY OF MR. DAHL TO WHICH YOU RESPOND IN YOUR DISCUSSION BELOW.

A. Mr. Dahl provides rebuttal testimony with respect to the various offsets that I propose in my Direct Testimony. I will briefly respond to each of his arguments.

Q. IS THERE ANY INITIAL OBSERVATION THAT YOU WISH TO MAKE WITH RESPECT TO THE COMPANY'S FILING BEFORE ADDRESSING YOUR

PROPOSED ADJUSTMENTS TO THE COMPANY'S UNIVERSAL SERVICE COST RECOVERY PROPOSAL?

A. Yes. I reiterate my concern about whether the Company maintains records in sufficient detail to support a periodic reconciliation of universal service program costs. Mr. Dahl asserts that the Company "tracks and retains detailed information regarding its CAP expenditures on a monthly basis" which would be "more than sufficient to support annual reconciliation of recovery of CAP expenses." (Dahl Rebuttal, at 5 – 6). Despite Mr. Dahl's broad, conclusory assertion, the actual data provided by Mr. Dahl does not support his statement.

Consider the fact that the OCA requested the Company to provide monthly expenditures on OnTrack credits, OnTrack arrearage forgiveness, and OnTrack administration for the months of January 2005 through May 2007. (OCA-XI-9). In its response, the Company confirmed that "PPL Electric does not have any other OnTrack expenditures that are not included in the above responses [relating to CAP credits, arrearage forgiveness, and administration]." (OCA-XI-9(D); see also, OCA-XI-13(D)). Schedule RDC-SR1 provides the data supplied by the Company in response to that OCA request for the 24 months of January 2005 through December 2006. Schedule RDC-SR1 further provides 2005 year end totals for both 2005 and 2006.

OCA then asked the Company what the year-end reconciliation would have been -- broken out by CAP credits, arrearage forgiveness credits, and administration-- had its proposed Universal Service Rider (USR) been in effect for the years 2004 through 2006.

The Company reported that the reconciliation process would have claimed $10,588,000 for CAP credits in 2005 and $9,802,000 for CAP credits in 2006. The Company reported further that it would have claimed $3,700,000 in arrearage forgiveness credits for both 2005 and 2006. (OCA-XI-10).

The numbers do not match up. While PPL reports spending $8,959,996 in CAP credits in 2006, as shown on Schedule RDC-SR1, line 26, the Company reports that it would have included more than $9.8 million in its 2006 reconciliation for CAP credits (OCA-XI-10). While the Company reports that it spent $4,462,296 in arrearage forgiveness credits in 2006, as shown on Schedule RDC-SR1, line 26, it reports that it would have claimed $3.7 million in its 2006 reconciliation for arrearage forgiveness. (OCA-XI-10). Similarly, while the Company reports that it spent $10,283,854 in CAP credits in 2005 (Schedule RDC-SR1, line 25), it reports in OCA-XI-10 that it would have claimed $10.6 million in its 2005 reconciliation for CAP credits. While it spent $3,341,687 in arrearage forgiveness in 2005 (Schedule RDC-SR1, line 25), it would have claimed $3.7 million in its 2005 reconciliation for arrearage forgiveness (OCA-XI-10). While in some cases, the numbers might be "close," in other cases the figures the Company reports as actual "expenditures" and the figures the Company reports it would have used in its reconciliation are different by a million dollars. The fact that the Company's report of actual "expenditures" differs significantly, and routinely, from the figures it reported it would use in its reconciliation process does not lend confidence that the Company can properly engage in cost tracking for purposes of the reconciliation process.

Q. PLEASE RESPOND TO MR. DAHL'S TESTIMONY REGARDING THE DISALLOWANCE OF CAP CREDITS THAT ARE NOT PAID DUE TO MISSED BILL PAYMENTS.

A. Under the Company's CAP program, a customer must make a timely bill payment in order to earn a CAP credit. If the OnTrack participant *misses* his or her timely bill payment, there is no "cure" provision. The opportunity to earn the CAP credit for that month is permanently forfeited.

Q. DOES THIS FORFEITURE OF THE CAP CREDIT HAVE AN IMPACT ON WHAT TOTAL CAP CREDIT COSTS WILL BE INCURRED BY THE COMPANY?

A. Yes. Each month that a customer forfeits his or her CAP credit because he or she does not make a bill payment on time will reduce the annual average CAP credit that will be paid through OnTrack and thus recoverable from other ratepayers. Assume hypothetically, for example, that we have one OnTrack participant who is eligible to receive $50 in CAP credits each month. If that customer makes 12 monthly bill payments in a full and timely fashion, the customer receives an average annual CAP credit of $600 ($50/month x 12 months). If the customer happens to miss three bill payments, however, the customer receives an average annual CAP credit of only $450 ($50/month x 9 months).

Q. HOW DOES THIS AFFECT SETTING A CAP BUDGET IN THIS PROCEEDING?

A. When it comes time to establish a CAP budget to be recovered from other ratepayers, it is necessary to take into account not only the months in which CAP credits are paid, but the months in which CAP credits are forfeited, since those forfeited months will reduce the average CAP credit per customer and thus the total CAP budget (average CAP credit per participant x number of participants = total CAP budget to be recovered from ratepayers).

Q. WHAT AVERAGE ANNUAL CAP CREDIT IS USED BY MR. DAHL TO ESTABLISH A TOTAL CAP BUDGET?

A. Mr. Dahl states in his rebuttal testimony that the average annual CAP credit in 2006 was $547 per customer. He states that application of that $547 figure to a participation rate of 22,000 to 24,000 results in an expenditure on CAP credits ranging from approximately $12.0 million to $13.1 million, supportive of the Company's proposed budget of $12.9 million for CAP credits.

Q. WHY DO YOU NOT FIND MR. DAHL'S USE OF AN AVERAGE CAP CREDIT OF $547 PER PARTICIPANT TO BE APPROPRIATE?

A. The first reason I do not believe Mr. Dahl's data to be appropriate is that the explanation he offers in his rebuttal testimony of how the Company's CAP budget was developed differs from the explanation he offered in response to OCA discovery on how the Company developed its CAP budget. In his rebuttal testimony, Mr. Dahl multiplies an average annual CAP credit ($547) times the number of expected CAP participants (either 22,000 or 24,000) to generate a CAP budget. In contrast, in response to OCA discovery asking for the derivation of the CAP budget, Mr. Dahl stated that the Company "considered the existing number of OnTrack customers at the end of 2006, data from the 2000 U.S. Census, the average monthly net enrollment and the average annual cost (approximately $850) per OnTrack customer to develop its proposed budget of $19 million." (OCA-XI-15).[1]

The Company did not separately develop a budget for CAP credits. The discovery response (OCA-XI-15) referred to the total CAP budget of $19 million, rather than the budget for CAP credits of $12.9 million.

As one can see, the $547 figure used by Mr. Dahl in his rebuttal testimony does not appear in the discovery response describing how the Company developed its OnTrack budget. Moreover, none of the factors which the discovery response reports the Company as having used to develop its CAP budget were referred to or used by Mr. Dahl in his rebuttal testimony.

Q. WHY IS THIS IMPORTANT IF THE $547 AVERAGE CAP CREDIT USED BY MR. DAHL PRESENTS ACCURATE DATA?

A. It is not clear that the $547 average CAP credit used by Mr. Dahl in his rebuttal testimony is accurate. Mr. Dahl's rebuttal testimony is not consistent with other data provided by the Company in this regard. Consider that the OCA asked for the "average annual CAP

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[1] It is not possible to examine how the Company used this data. The Company said in its discovery responses that it "does not have any work papers showing the derivation of the $19 million associated with participation in OnTrack," (OCA-XI-15). The Company further stated that "PPL Electric has no detailed work papers regarding the requested additional funding of $5.8 million for its Customer Assistance Program (known as OnTrack)." (OCA-XI-8).

credit for [the] total number of OnTrack participants" for each year 2004 to present. For 2006, the same year Mr. Dahl reports an average CAP credit of $547 in his rebuttal testimony, the Company reported a CAP credit of $527 (OCA-XI-31).

Other data provided by the Company is inconsistent with the $547 figure used by Mr. Dahl in his rebuttal testimony as well. In response to OCA discovery, the Company provided the actual "expenditures" on CAP credits by month in 2006. These monthly figures sum to an annual total of $8,959,996. (OCA-XI-9A). When those actual 2006 "expenditures" are divided by the average monthly number of actual CAP participants for 2006 (17,788 as reported in OCA-XI-11), the average actual "expenditures" on CAP credits in 2006 is $504 ($8,959,996 / 17,788 = $504).

Q. CAN YOU SUMMARIZE WHY YOU BELIEVE THAT THE $547 AVERAGE CAP CREDIT USED BY MR. DAHL IS AN INAPPROPRIATE BASIS FOR CALCULATING A TOTAL CAP BUDGET?

A. Yes. First, the $547 figure is used to develop a CAP budget through a methodology that differs from the methodology reported by the Company in its discovery responses as having been used. Second, the $547 figure differs from other "average CAP credits" reported by the Company for the same time period. Third, the $547 figure does not tie out to other data provided by the Company that should be usable in calculating an average CAP credit.

Q. CAN YOU APPLY THE METHODOLOGY USED BY MR. DAHL IN HIS REBUTTAL TESTIMONY TO CHECK THE ACCURACY OF THE ADJUSTMENT YOU RECOMMENDED IN YOUR DIRECT TESTIMONY?

A. Yes. In my Direct Testimony, I proposed reducing the Company's claimed CAP expenditure of $12.9 million by a factor of 0.71. That resulted in a cost recovery of $9,159,000 ($12,900,000 x 0.71 = $9,159,000).

It is possible to test the accuracy of that figure by multiplying an average CAP credit times the number of CAP participants.

- The Company reports an actual annual expenditure on CAP credits of $8,959,996 in 2006. (OCA-XI-9A).
- The Company reports an average CAP participation rate of 17,788 in 2006. (OCA-XI-11).
- That yields an average CAP credit of $504 ($8,959,996 / 17,788 = $504).
- The Company reports a LIHEAP offset for 2006 of $1,873,809. (OCA-XI-10). Given the average CAP participation rate of 17,788, that is an average LIHEAP offset of $105 per participant ($1,873,809 / 17,788 = $105.34).
- The net CAP credit is thus $399 ($504 - $105 = $399).

Using the same methodology employed by Mr. Dahl in his rebuttal testimony, I can then calculate a range of dollar recovery:

- Assuming 22,000 OnTrack participants, there is a CAP credit expenditure of $8,778,000 (22,000 participants x $399 per participant = $8,778,000).

- Assuming 24,000 OnTrack participants, there is a CAP credit expenditure of $9,576,000 (24,000 participants x $399 per participant = $9,576,000).

Using the data provided by the Company, and using the same methodology used by Mr. Dahl, I find a range of dollars that supports my original proposal. The proposal contained in my Direct Testimony ($9.2 million) falls squarely within the range of $8.8 million to $9.6 million determined above.

Q. WOULD THIS SAME ANALYSIS APPLY TO YOUR CALCULATION OF ARREARAGE FORGIVENESS COSTS?

A. Yes. Mr. Dahl has provided no data that would indicate that the Company uses a different methodology for its arrearage forgiveness expenditures. Indeed, when requested to provide work papers supporting its CAP budget, including arrearage forgiveness, the Company responded that it had "no detailed work papers" (or that it had no work papers at all) to provide in support of its proposed budget. (OCA-XI-8; OCA-XI-15).

Q. GIVEN THAT THESE FIGURES ARE SUBJECT TO RECONCILIATION ON AN ANNUAL BASIS, WHY DOES THIS DISCUSSION MAKE A DIFFERENCE?

A. The efficacy of annual reconciliation depends on the fundamental assumption that the data to be used in the reconciliation is known with certainty and the methodology to be used in reconciliation is transparent. Only if these two assumptions are met can the Company, the OCA and other stakeholders determine whether the reconciliation of "actual" expenditures against budgeted expenditures is accurately occurring. Based on my discussion above, as well as the observations in my Direct Testimony, I have ongoing concerns about whether these two assumptions can be met. There is data which appears to differ even though it is reported to be from the same time period. There are inconsistent methodologies advanced for determining budgets.

Should the discussion above be postponed until the time of reconciliation, I would recommend that the Company be required to regularly report CAP expenditure data to the Commission *before* the time of reconciliation occurs. It would not be appropriate to discover at the time of reconciliation that there is a data and methodology problem that could not appropriately be resolved in the time frame devoted to the reconciliation process. Should the discussion above be postponed until the time of reconciliation, I recommend that the Company provide quarterly reports (of monthly data) with the following data:

- The number of CAP participants receiving a CAP credit on their bill each month;
- The number of CAP participants with a CAP credit reversed on their bill each month for bill nonpayment or any other reason;[2]
- The number of CAP participants with an arrearage forgiveness credit on their bill each month;
- The number of CAP participants with an arrearage forgiveness credit reversed on their bill each month for nonpayment or any other reason;
- The dollars of CAP credit billed each month;
- The dollars of CAP credits reversed on bills each month;

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[2] The Company provides each CAP participant with a CAP credit each month. If the CAP participant fails to make a full and timely basis, that CAP credit is reversed on the *next* month's bill.

- The dollars of arrearage forgiveness credit billed each month; and
- The dollars of arrearage forgiveness credits reversed each month.

The data should be provided in electronic format. The account-specific data that underlies each monthly aggregated figure should be retained in accessible form so that the Company's reported data can be replicated and verified if requested.

Q. WOULD THIS DATA COLLECTION AND REPORTING RESOLVE YOUR CONCERNS?

A. No. Despite this data reporting I recommend above, I do not recommend that the reconciliation process be relied upon to correct any budgeting errors in this base rate case. It is important for the CAP budget to be set as accurately as possible in this base rate case. Even if over- or under-projections could be completely "worked out" in the reconciliation process, having large swings in over- and under-collections is not the ideal way to operate a CAP. While CAP participants may be exempt from paying the universal service surcharge, not all confirmed low-income customers are exempt. While PPL has roughly 22,000 CAP participants, it has 100,000 or more confirmed low-income customers. (OCA-XI-11). The interest paid on over-collections does not adequately compensate these confirmed low-income customers for the use of their money between the time the projected cost is paid in rates and the time any over-collection is reconciled. In addition, given the frequent mobility of low-income customers, even if all under- or over-collections were exactly captured in the reconciliation process, it is likely that different customers will be paying the under-collection (or receiving the payment back of over-collections). Accepting wide swings in over- and under-collections institutionalizes a mismatch between those customers actually paying the universal service costs and those customers that should be paying those costs.

Q. PLEASE RESPOND TO MR. DAHL'S TESTIMONY ON USING A CREDIT AND COLLECTION OFFSET TO THE CAP BUDGET.

A. Mr. Dahl provides a generalized critique of using *any* credit and collection offsets as a source of funding for the Company's OnTrack program. Despite the long-standing nature of the PPL OnTrack program, Mr. Dahl asserts that the Company has no methodology to calculate an offset for credit and collection costs. Mr. Dahl criticizes me for not providing the names of the utilities upon which I relied, but that information was provided through discovery propounded to OCA. Mr. Dahl also asserts that "savings realized at one utility may not be transferable to another utility." But the Company's *own* CAP program evaluation contained this statement: "About $30 of the OnTrack administrative cost to ratepayers per enrolled customer *is offset by savings in collection expenses*." ("Evaluation of PPL Electric's Universal Service Programs," Section 7.3.1, page 128, October 2002) (emphasis added). The Company's *own* evaluation stated that PPL Electric had an administrative cost of $177, which is "adjusted by subtracting the *avoided collection cost* of about $30 per OnTrack participant." (page 128) (emphasis added). As can be seen, Mr. Dahl's critique of my proposed credit and collections offset is unfounded. His critique is not supported by his own Company's universal service evaluation.

Q. PLEASE RESPOND TO MR. DAHL'S TESTIMONY REGARDING ADMINISTRATIVE COSTS.

A. Mr. Dahl agrees that administrative costs should be collected through base rates. He proposes, however, to collect $35,820 in administrative costs paid to outside contractors through the Rate Rider. I agree that including such variable administrative costs paid to outside contractors is an appropriate administrative expense to be included in the Rate Rider.

Q. PLEASE RESPOND TO MR. DAHL'S TESTIMONY REGARDING THE DOUBLE COLLECTION OF BAD DEBT EXPENSES.

A. Mr. Dahl does not agree that the Company's collection of 100% of its CAP credits and arrearage forgiveness for incremental OnTrack participants would result in a double recovery of CAP customer costs. He asserts that the Company does not experience a double recovery because it tracks its residential uncollectibles and its OnTrack expenses separately. Mr. Dahl errs when his analysis is applied to incremental OnTrack participants. Even if the residential uncollectibles and OnTrack expenses are separately tracked for existing OnTrack participants, the costs associated with *incremental* future participants, as I address in my testimony, will *__not__* have been segregated at the time of this rate case. The adjustment I propose is necessary to prevent the double-recovery of bad debts.

Mr. Dahl's claim that the Company would not double-recover its bad debt, both associated with CAP credits and associated with arrearage forgiveness, is inconsistent with the Company's own program evaluation as well. The Company's own evaluation states that "while the OnTrack budget shows a cost of roughly $1,000 per enrolled customer, much of this is subsidy credits reducing debts that would eventually be written off." (PPL Evaluation, at 2). The Company's evaluation states that:

> Principal Evaluator David Cross conducted a very detailed analysis of PPL's high debt low income customers in 1998, as part of an evaluation of the OnTrack program in its pilot phase. He concluded that 15% - 20% of low-income overdue debt is eventually paid off by the customers themselves, and that 80% will eventually be written off (if it is not forgiven by OnTrack).

(PPL Evaluation, at page 14, fn. 2). The PPL Evaluation stated: "It should be noted that the OnTrack budget, while it is critical to program managers and accountants, _does not fairly represent the net cost of the program to ratepayers_. We estimate that 80% of forgiveness credits and 60% to 70% of shortfall credits are dollars that would eventually be written off if OnTrack did not allow PPL to expense them now." (PPL Evaluation, at 128) (emphasis added). With respect to the incremental participants in OnTrack, as first recognized in the Company's own program evaluation, as I discussed in my Direct Testimony, there will be a double recovery of bad debt costs in the absence of the adjustment that I propose. Mr. Dahl's argument that there is no double recovery is not supported by the Company's own program evaluation. This assessment provided in the Company's own program evaluation remains equally true today. As the Company, itself, observes, "all new enrollees in OnTrack have account characteristics (e.g., overdue balances, collection notices, and defaulted payment plans) that put their accounts at risk of being uncollectible" in the absence of the program. (OCA-XI-29).